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Appendices for the
State of Arkansas
Regional Haze Rule
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Appendix 9.2D

ENVIRON Final Report

Final Report

Cumulative Modeling of Subject to Best Available Retrofit Technology (BART) Facilities as a Requirement of ADEQ's BART Modeling Protocol

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1.0 INTRODUCTION

OVERVIEW

The Clean Air Act (CAA) established 156 Federally-protected National parks, wildlife refuges and wilderness areas (Class I areas) where visibility was determined to be an important value. To meet Sections 169A and 169B of the CAA, the United States Environmental Protection Agency (EPA) promulgated the Regional Haze Rule (RHR) on July 1, 1999 (64 Federal register 35714, 40 CFR Part 51, Sections 51.3000-51.309). The RHR requires States to submit State Implementation Plans (SIPs) to address regional haze visibility impairment in 156 Class I areas. In addition, Section 169A(b)(s)(A) of the CAA required EPA to include in the final RHR a requirement for certain emission sources "that may reasonably be anticipated to cause or contribute" to visibility impairment in downwind Class I areas to install Best Available Retrofit Technology (BART) controls. Sources are potentially BART-eligible if they meet three criteria:

(a) potential emissions of at least 250 tons per year (tpy) of a visibility-impairing pollutant;
(b) in operation between August 7, 1962 and August 7, 1977; and
(c) one of 26 listed source categories in the guidance.

Potential BART-eligible sources are evaluated to determine whether they cause or contribute to visibility impairment at a Class I area. If a potential BART-eligible source is shown to contribute significantly to visibility impairment then it is subject to BART and must evaluate what constitutes BART controls for that source and whether such controls should be implemented accounting for:

(a) any pollution control equipment in use at the source which affects the availability of options and their impacts;
(b) the costs of compliance with control options;
(c) the remaining useful life of the facility;
(d) the energy and non-air-quality environmental impacts of compliance; and
(e) the degree of improvement in visibility that may reasonable be anticipated to result from the use of such technology.

On July 6, 2005 EPA published final amendments to its 1999 RHR in the Federal Register that included Appendix Y, the final guidance for BART determinations. The preamble to the rule states "…in weighing the factors set forth in the statute for determining BART, the States should consider the collective impact of BART sources on visibility." This document presents the results of the State of Arkansas cumulative analyses that were aimed to evaluate the collective contribution of all Arkansas subject-to-BART sources on visibility impairment in Class I areas.

Arkansas BART Determinations

There are two Class I areas within the State of Arkansas, Caney Creek and Upper Buffalo Wilderness Areas for which the United States Department of Agriculture (USDA) Forest Service (FS) is the Federal Land Manager (FLM). The maximum distance that BART sources visibility impacts should be assessed is not addressed in EPA's BART guidance. However, the Central Regional Planning Association (CENRAP), that includes Arkansas, has adopted a 300 km maximum distance. Three additional Class I areas are within 300 km of Arkansas and are

Hercules Glade Wilderness Area (USDA FS), Mingo National Wildlife Refuge (USDOI Fish and Wildlife Service) and Sipsey Wilderness Area (USDA FS).

The Arkansas Department of Environmental Quality (ADEQ) identified 18 potential BART-eligible sources in Arkansas. ADEQ performed single-source exemption modeling using the CALPUFF model and determined that approximately 9 units at 6 facilities are subject to BART. Therefore, these facilities are required to evaluate BART controls, install BART controls if necessary and perform post control modeling to determine the degree of visibility improvement that the BART controls provide. In accordance with Appendix Y of EPA's final guidance for BART determinations (70 FR 39104-39172), cumulative modeling needs to be performed to determine the collective impact of the Arkansas BART sources on visibility at Class I areas.

MODELING APPROACH

The EPA BART guidelines recommends that the CALPUFF modeling system, or other alternative model, be used to determine whether a potential BART-eligible source contributes significantly to visibility impairment so is subject to BART. The BART guidelines also suggests doing group BART exemption modeling using a photochemical grid model (PGM) where you model the visibility impacts due to a group of BART sources and if you can show that they do not contribute significantly to visibility impairment as a group then each individual source in the group would also not contribute significantly so can be exempt from BART. As discussed below, for cumulative BART modeling, a PGM would be a more appropriate choice than CALPUFF due to more scientifically accurate treatment of secondary particulate matter (PM) formation and long-range transport and dispersion.

EPA Guidance on Air Quality Models

The BART determination under the Regional Haze Rule seeks to quantify the impact of source emissions of SO_2, NOx, and direct PM ($PM_{2.5}$ and/or PM_{10}) on daily visibility impairment at receptors located within downwind Class I areas. Since visibility is defined in the context of light extinction, which itself is determined by atmospheric concentrations of specific fine particulate species (like sulfate, nitrate, organic carbonaceous matter, elemental carbon, other fine particles and coarse mass), logic dictates that the modeling method(s) used must be capable of simulating these components reliably.

EPA's position on recommended models for fine particulate and visibility estimation ***from single point sources*** is clearly set out in the Final BART Rule and in the BART modeling guidance (EPA, 2005). The Final BART Rule (pg 101) states, "Because the air quality model CALPUFF is currently the best application available to predict the impact of a single source on visibility in a Class I area, we proposed that CALPUFF assessment be used as the preferred approach first, for determining whether an individual source is subject to BART, and second, in the BART determination process. CALPUFF can be used to estimate not only the effects of directly emitted $PM_{2.5}$ emissions from a source, but also to predict the visibility impacts from the transport and chemical transformation of fine particle precursors." The Rule goes on to state (pg 110) that "regional scale modeling typically involves use of a photochemical grid model that is capable of simulating aerosol chemistry, transport, and deposition of airborne pollutants, including particulate matter and ozone. Regional scale air quality models are generally applied for geographic scales ranging from a multi-state to the continental scale. Because of the design and intended applications of grid models, they may not be appropriate for BART assessments, so States should consult with the appropriate EPA Regional Office prior to carrying out any such modeling."

In contrast, EPA's draft "Guidance for Demonstrating Attainment of the Air Quality Goals for $PM_{2.5}$ and Regional Haze" (EPA, 2001) sets forth the types of models that should be used for simulating secondary fine particulate and visibility for SIPs. EPA states (pg 169): "States should use a regional scale photochemical grid model to estimate the effects of a control strategy on secondary components of PM. Changes in primary components may be estimated using a numerical grid model (with no chemistry), a Lagrangian model, or in some cases a receptor model." Thus, in its Regional Haze and $PM_{2.5}$ SIP modeling guidance, EPA indicates that CALPUFF (a Lagrangian non-steady-state Gaussian puff model) should not be used for secondary PM and visibility impacts at Class I areas, but rather is relegated to the category of estimating primary species.

Thus, on the one hand, EPA maintains that CALPUFF is the "best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment" and notes, "it is the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of primary pollutants." However, only regional grid models with appropriate chemistry are to be used in developing $PM_{2.5}$ and Regional Haze SIPs. EPA has attempted to reconcile these two positions in the Final BART Rule by asserting that (a) regional models were not developed to treat individual point sources, and (b) CALPUFF's secondary aerosol chemistry is adequate for estimating relative benefits of controls on BART sources.

More recent developments in photochemical grid modeling should alleviate some of the concerns related to using them for single-source and cumulative visibility assessments. In particular, the use of finer grid spacing and new PM Plume-in-Grid (PiG) modeling techniques can extend the grid model's applicability to assess the visibility impacts of a single source and groups of sources.

CALPUFF Modeling Recommendations

To evaluate the visibility impacts of a BART-eligible source at Class I areas beyond 50 km from the source, the EPA guidance recommends the use of the CALPUFF model (Fed. Reg., 2003). For modeling the impact of a source closer than 50 km to a Class I area, EPA's BART guidance recommends that expert modeling judgment be used "giving consideration to both CALPUFF and other methods." The Plume Visibility Model (PLUVUE)-II model is mentioned as a possible model to consider in addition to CALPUFF within 50 km of a source. The EPA guidance notes that regional scale photochemical grid models may have merit, but such models are resource intensive relative to CALPUFF. Photochemical grid models are clearly more appropriate for cumulative modeling options, such as in the determination of the aggregate contribution of all-BART-eligible sources to visibility impairment, but such use should involve consultation with the appropriate EPA Regional Office.

CALPUFF is recommended for ascertaining whether a source may be exempted from BART. If a source is determined to be subject to BART, CALPUFF or another appropriate model should be used to evaluate the improvement in visibility resulting from the application of BART controls. Emissions reflecting periods of start-up, shutdown, and malfunction are not to be considered in determining the appropriate emission rates. The EPA recommends that the state use the highest 24-hour average actual emission rate for the most recent five-year period (excluding periods with start-up, shutdown, and malfunctions). Visibility improvements may be evaluated on a pollutant-specific basis. States are encouraged to account for the magnitude, frequency, and duration of the contributions to visibility impairment caused by the source when assessing whether the source is reasonably anticipated to cause or contribute to visibility impairment at a Class I area.

Alternative Models for BART Analyses

All air quality models potentially suited to BART analysis share a common foundation: the species-conservation (or atmospheric diffusion) equation. Source-oriented air quality models, including CALPUFF, derive from this equation that applies equally to one source or a million or more sources. The distinction lies in how the various terms are treated (CAMx, CMAQ) or neglected (CALPUFF) in the governing equations and the choice of coordinate system (Lagrangian or Eulerian). As shown in the next section, much of the simplicity of the CALPUFF model derives from the fact that many chemical and physical processes known to influence visibility are simply ignored or highly simplified. In contrast, comprehensive regional models treat these processes in detail, albeit at the expense of greater computer resources and data needs. EPA’s BART guidance allows for the use of alternative models on a case-by-case basis.

EPA’s dismissal of regional scale photochemical grid models ignores a very substantial body of research and model development carried out at the agency and elsewhere in the U.S. over the past 20 years. Although grid models have generally been applied at geographic scales ranging from a multi-state to the continental scale, and were not initially designed to simulate individual point sources, modern one-atmospheric regional photochemical grid models, employing nested grid (Kumar and Russell, 1996) and Plume-in-Grid techniques (Karamchandani et al., 2002; ENVIRON, 2006), are fully applicable to the analysis of point source plumes, most especially when reactive atmospheric chemistry occurs. If they were not, then they would not be reliable in simulating the combined effects of the wide array of anthropogenic and biogenic emissions that cause gas phase, particulate, secondary aerosol, and visibility air pollution problems. Furthermore, the convergence of fast commodity-based Linux computer clusters and recently-developed regional modeling emissions, meteorological, and air quality data bases make application of these modeling platforms no longer a research or academic exercise. While regional scale modeling clearly requires expertise to perform properly, the actual program costs to conduct a CMAQ or CAMx regional modeling study are quite comparable with, and often less than, a traditional Prevention of Significant Deterioration (PSD) modeling study using the Industrial Source Complex Model (ISC), CALPUFF, or American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee Model (AERMOD). Given grid nesting and Plume-in-Grid technology, modern regional models are applicable to a very broad range of scales from 10-20 km to continental scale. In fact, regional photochemical grid models have been applied with grid spacing down to hundreds of meters on occasion (Kemball-Cook, Emery and Yarwood, 2005). Regional photochemical grid models are clearly more appropriate than CALPUFF for cumulative modeling requirements such as in the determination of the aggregate contribution of all-BART-eligible sources to visibility impairment. And as confirmed in EPA's fine particulate and regional haze modeling guidance discussed previously (EPA, 2001) and clearly shown by Morris and co-workers (2003; 2005; 2006), regional photochemical grid models, such as CMAQ and CAMx, provide a much more accurate and technically correct representation of the formation of secondary PM species, such as SO_4, NO_3 and secondary organic aerosols (SOA), than CALPUFF.

Model Selection

Two photochemical grid models are used for regional haze modeling: EPA's Community Multi-scale Air Quality (CMAQ) modeling system (Byun and Ching, 1999) and the Comprehensive Air-quality Model with extensions (CAMx; ENVIRON, 2006). Both models have been set up by the Central Regional Air Planning (CENRAP) Regional Planning Organization (RPO) for annual visibility modeling of 2002 on a 36/12 km grid. With proper configuration to better simulate the impacts from point source plumes, either model would be appropriate for the Arkansas cumulative BART modeling analysis. Both models contain a "one-atmosphere" treatment of gas-phase and aerosol chemistry and both models treat the necessary PM species needed to perform the BART visibility modeling. Thus, the selection of one model over the other boils down to three main factors:

1. Which model can best treat the visibility impacts of the BART point sources in Arkansas on Class I areas in and nearby Arkansas?
2. What model and modeling approach would be most acceptable and approvable by EPA? and
3. Which modeling approach can be set up the easiest and most efficiently perform the modeling analysis required?

1. <u>Treatment of Visibility Impacts due to Arkansas BART Sources</u>: The Arkansas BART sources are point sources that have concentrated point source plumes. Currently the CENRAP modeling database finest resolution is 12 km, which is too coarse to simulate the chemistry of point source plumes. Consequently a finer grid mesh is needed and/or a Plume-in-Grid (PiG) module should be used. For CMAQ this would involve running MM5 at a finer grid resolution and using the PinG module that requires much additional work. However, in CAMx the flexi-nest feature can be used to automatically generate a finer mesh grid over Arkansas and the PiG module can be invoked through simply specifying the PiG flag in the point source file for the BART sources.

2. <u>Most Acceptable to EPA</u>: The Texas Commission of Environmental Quality (TCEQ) performed group BART exemption screening analysis modeling (ENVIRON, 2006; Morris and Nopmongcol, 2006) using the CAMx model with an enhanced CENRAP database, PiG and the PM Source Apportionment Technology (PSAT) (see: http://www.tceq.state.tx.us/implementation/air/sip/bart/haze.html). This methodology was reviewed by EPA Region 6 and the Modeling Protocol was deemed an acceptable approach.

3. <u>Efficient Model Application</u>: Because of the flexi-nest feature, full-chemistry PiG and PSAT capabilities, use of the CAMx model for the Arkansas BART group modeling would be easier and more cost-effective than using CMAQ.

Based on these criteria, the CAMx model was selected for the Arkansas BART cumulative modeling analysis.

PURPOSE

The ADEQ, Air Division, Planning and Air Quality Analysis Branch (PAQAB) has contracted with ENVIRON International Corporation and Alpine Geophysics, LLC to perform cumulative BART modeling analysis of the 6 subject-to-BART facilities in Arkansas. This analysis assessed the cumulative visibility impacts due to the Arkansas subject-to-BART sources at nearby Class I areas. The modeling was performed so that the individual visibility impacts can be obtained for each BART sources as well as for each visibility precursor (e.g., SOx). The results will be included with the Arkansas visibility SIP due December 17, 2007.

The ADEQ cumulative BART was build off the regional photochemical being conducted by CENRAP (Morris et al., 2005d). In particular, the CENRAP 2002 36 km Base F CAMx modeling database was enhanced to include a 12 km grid over Arkansas and nearby States using the CENRAP 12 km MM5 output. A 4 km grid was specified over Arkansas and portions of adjacent States. CAMx PM Source Apportionment Technology (PSAT) modeling was conducted for Arkansas BART-eligible sources' SO_2, NOx and PM emissions. Each Arkansas BART source was treated by the CAMx Plume-in Grid (PiG) module to properly simulate near-source plume chemistry and dynamics. The cumulative, individual and pollutant-specific visibility impacts at Class I areas were assessed and reported to the ADEQ. This approach is fully consistent with the CENRAP draft BART Modeling Protocol (Alpine Geophysics, 2005).

Arkansas BART Cumulative Modeling Protocol

Prior to performing the Arkansas cumulative BART modeling analysis, a Modeling Protocol was prepared that provided details on the modeling approach to be used for the cumulative modeling of subject to BART facilities (ENVIRON, 2007). The Modeling Protocol was reviewed by the ADEQ, EPA and others prior to performing the analysis. The Arkansas Cumulative BART Analysis Modeling Protocol contained a summary of the BART requirements taken from EPA's BART guidelines (EPA, 2005) and BART Modeling Protocols prepared by CENRAP (Alpine Geophysics, 2005).

2.0 MODELING APPROACH

This section describes the modeling approach and databases that were used to perform the Arkansas cumulative BART analysis of the Arkansas subject-to-BART sources.

2002 ANNUAL 36/12/4 KM MODELING DATABASE

The Arkansas cumulative BART modeling analysis was performed using the CAMx model (ENVIRON, 2006) and the 2002 annual regional photochemical modeling database developed by CENRAP (Morris et al., 2005d). CENRAP has developed a 2002 annual modeling database for CAMx on the 36 km unified national RPO grid that covers the continental United States. This database was developed following the procedures outlined in the CENRAP Modeling Protocol (Morris et al., 2004a) and CENRAP modeling Quality Assurance Program Plan (QAPP) (Morris and Tonnesen, 2004b). The CENRAP preliminary base case model performance evaluation results for the CAMx model on the national 36 km grid using the CENRAP Base A emissions is given in Morris et al., (2005d) and subsequent model performance evaluations for the 2002 Base B, C and F emission scenarios are provided on the CENRAP modeling website (http://pah.cert.ucr.edu/aqm/cenrap/cmaq.shtml). The CENRAP Modeling Protocol, QAPP, preliminary Base A evaluation reports and Base B, C and F model performance results provide details on the development of the CENRAP 2002 36 km annual modeling database. Below, additional information is provided on enhancements to the CENRAP database for use in the Arkansas cumulative BART modeling analysis.

Enhancements to the CENRAP 2002 Modeling Database

The CENRAP 2002 36 km annual CAMx evaluation using the Base A emissions and CAMx Version 4.20 is reported in Morris and co-workers (2005d) with additional model performance evaluation displays available on the CENRAP modeling Website (http://pah.cert.ucr.edu/aqm/cenrap/cmaq.shtml#camx). CENRAP is currently updating the CAMx 2002 36 km base case simulation using the Base F base case emissions and CAMx version 4.40. The Base F base case database and CAMx Version 4.40 were used as the starting point for the Arkansas cumulative BART modeling analysis.

The CENRAP Base F 2002 36 km annual CAMx photochemical modeling database was updated to include a 12 km nested-grid that covers Arkansas, Louisiana, Mississippi and Alabama and portions of Texas, Oklahoma, Kansas, Missouri, Illinois, Indiana, Ohio, Kentucky, Tennessee, North Carolina and Georgia. A 4 km grid was specified over Arkansas and portions of adjacent states including the key Hercules-Glade and Mingo class I areas in southern Missouri. Figure 2-1 displays the 36/12/4 km nested grid structure for the Arkansas CAMx cumulative BART modeling analysis. The modeling domains includes all of the primary and several secondary Class I areas of interest:

- Caney Creek, Upper Buffalo, Hercules Glade and Mingo Class I areas, of the 5 primary Class I areas of interest, would reside in the 4 km grid;
- Sipsey, the 5th primary Class I area of interest, would reside in the 12 km grid; and
- The 12 km grid would also include several Class I areas that are further than 300 km from Arkansas that are of secondary interest (Wichita Mountains, Mammoth Cave, Great Smoky Mountains, Breton and Cohutta).

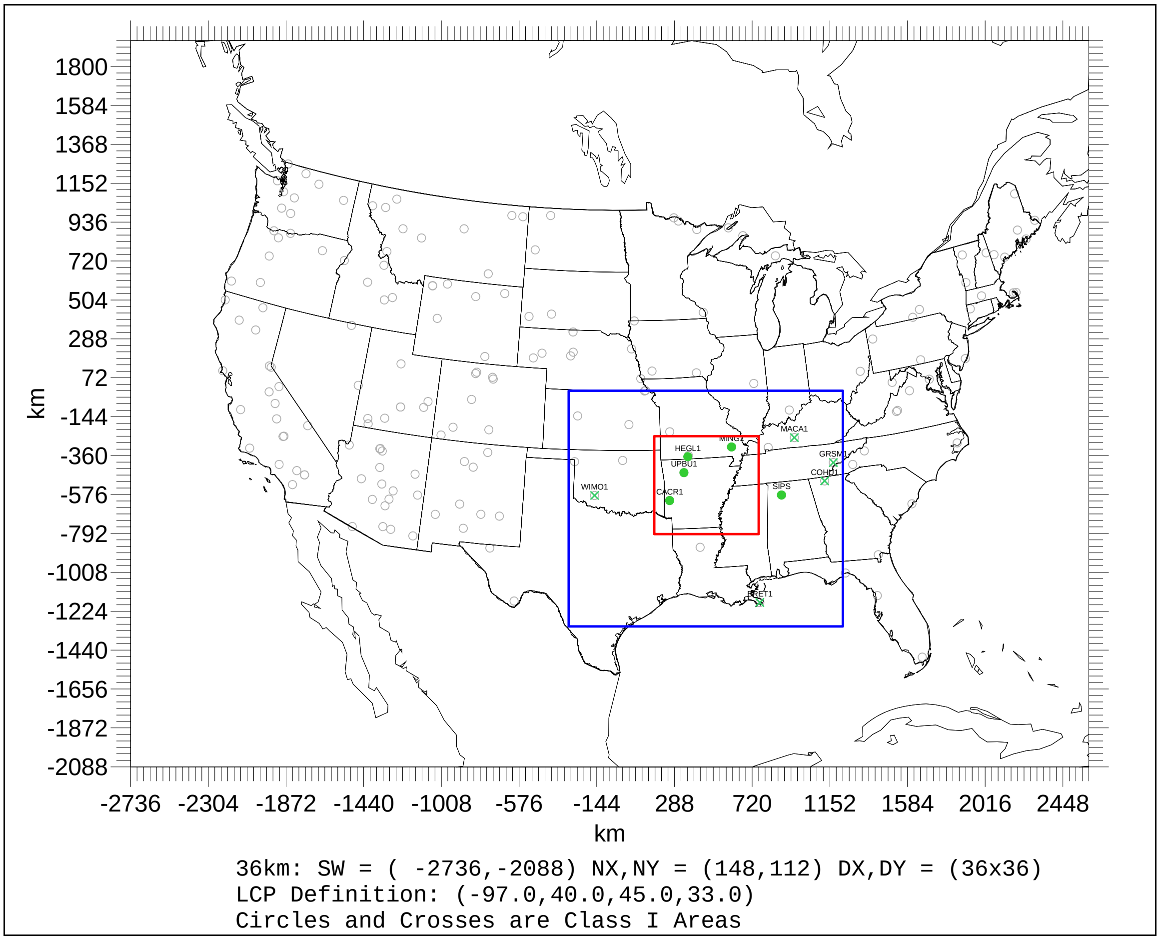


Figure 2-1. Arkansas cumulative BART modeling 36/12/4 km modeling domain and the locations of primary (green dots) and secondary (green x) Class I areas of interest.

The CENRAP 12 km MM5 outputs were processed to generate CAMx meteorological inputs for the 12 km grid. The model performance of the 12 km MM5 fields was evaluated using wind, temperature and humidity observations within the 4 km domain. The performance was deemed acceptable and comparable to the CENRAP 12km MM5 evaluation over the southern domain (available on the CENRAP modeling website http://pah.cert.ucr.edu/aqm/cenrap/ppt_files/ CENRAP_2002_36km_vs_12km_MM5_May22_2006.ppt). Thus, flexi-nesting 4 km domain using 12 km MM5 should be sufficient for Arkansas cumulative BART modeling.

The locations of the Arkansas subject-to-BART sources and Class I areas within the 12 km and 4 km modeling domains are shown in Figures 2-2 and 2-3, respectively. The original intent was to perform the CAMx modeling using two-way interactive grid nesting on the 36/12/4 km nested-grid domains depicted in Figure 2-1. However, memory requirements of the CAMx configuration on the 36/12/4 km grid were too excessive. Consequently, 36 km CAMx simulations were performed and processed to provide boundary conditions (BCs) to the 12/4 km (i.e., one-way nesting between the 36 km and 12 km grids). Area emissions were disaggregated from 36 km to 12 km resolution. The annual CAMx runs were performed on the 12/4 km grid domain using the full two-way flexi-nesting in which CAMx internally interpolates emissions, meteorological and other inputs from the 12 km grid to the 4 km grid.

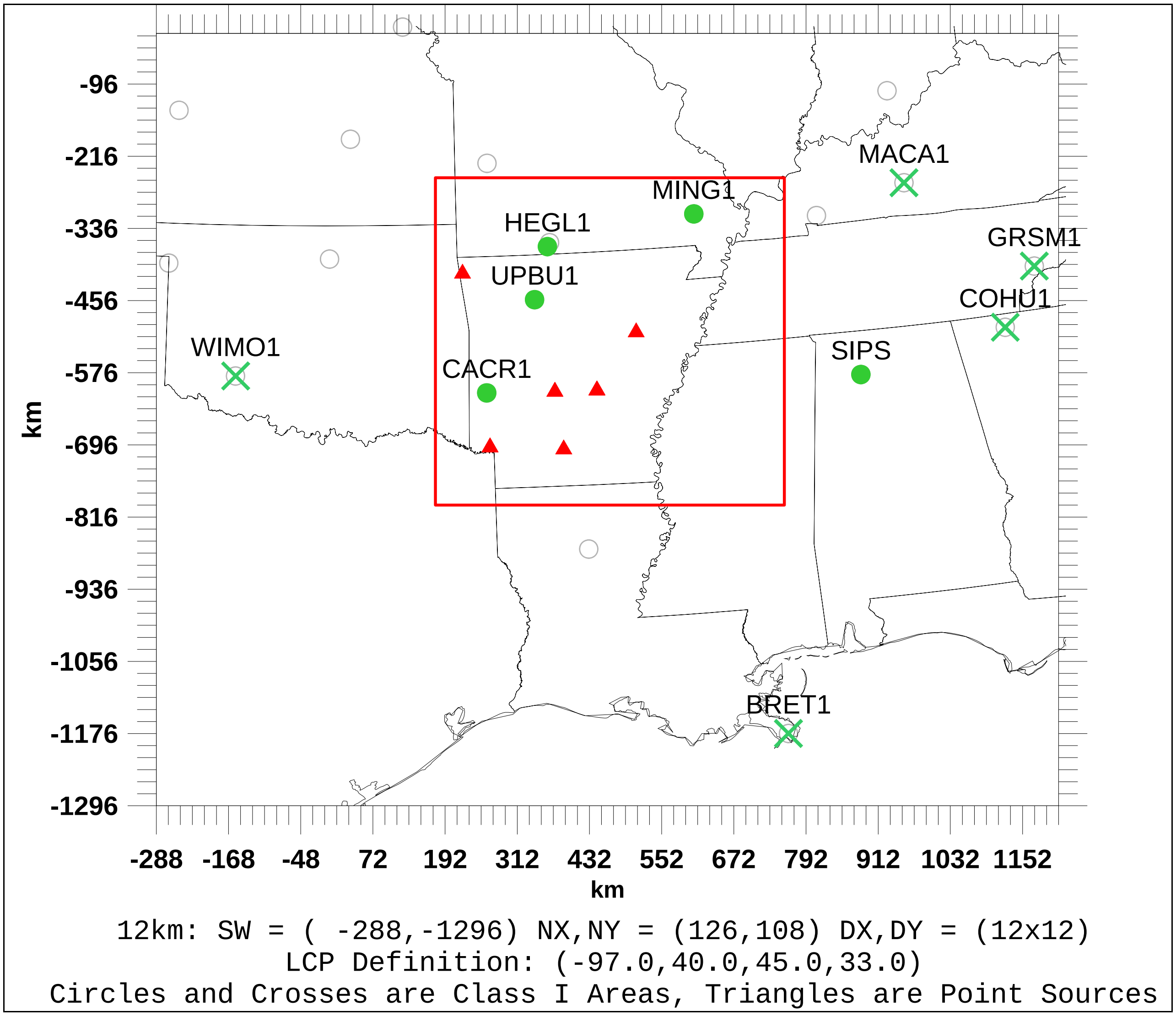
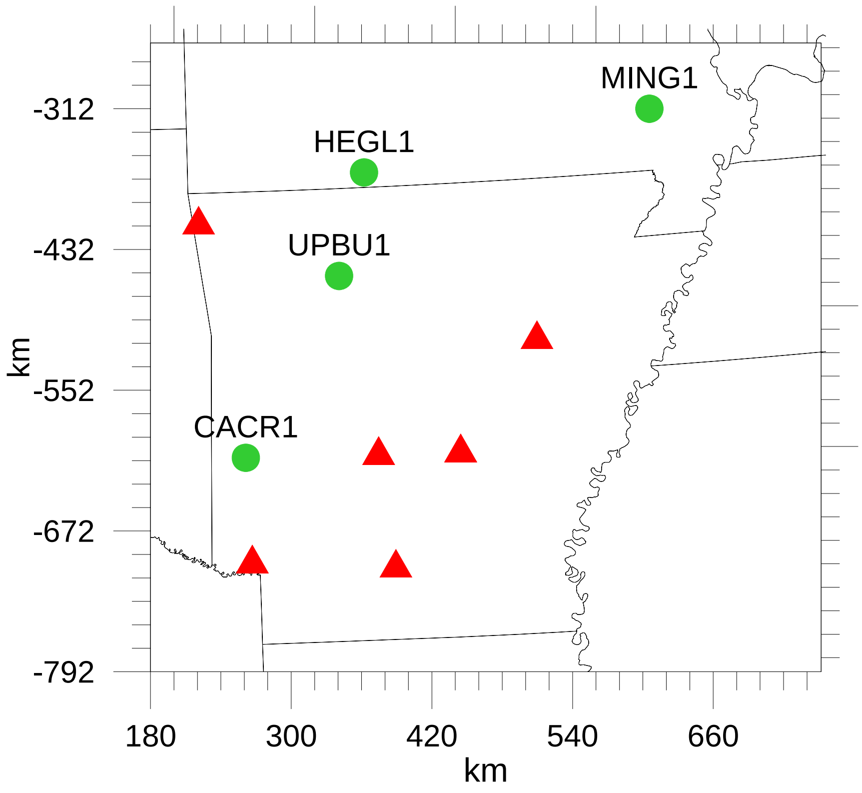


Figure 2-2. Arkansas cumulative BART modeling 12/4 km modeling domain, locations of BART-eligible sources in Arkansas (red triangles) and primary (green dots) and secondary (green x) Class I areas of interest.



`4km: SW = ( 180,-792) NX,NY = (144,135) DX,DY = (4x4)`
`LCP Definition: (-97.0,40.0,45.0,33.0)`
`Circles and Crosses are Class I Areas, Triangles are Point Sources`

Figure 2-3. Arkansas cumulative BART modeling 4 km modeling domain, locations of BART-eligible sources in Arkansas (red triangles) and primary (green dots) Class I areas of interest.

ENHANCEMENTS TO THE PM SOURCE APPORTIONMENT TECHNOLOGY

For the Arkansas cumulative BART modeling analysis, the CAMx PM Source Apportionment Technology (PSAT) was used to separately track the PM contributions of each BART facility and to provide separate visibility impacts due to each major visibility precursor (i.e., from SOx, NOx and primary PM emissions). PSAT was recently updated to be compatible with the CAMx Plume-in-Grid (PiG) module. The next section describes the technical formulation of the PSAT source apportionment technique and the enhancements to the CAMx PiG and PSAT to make them compatible with each other.

PSAT Formulation

PSAT is designed to source apportion the following PM species modeled in CAMx:

- Sulfate (SO_4)
- Particulate nitrate (NO_3)
- Ammonium (NH_4)
- Particulate mercury (Hg(p))
- Secondary organic aerosol (SOA)
- Six categories of primary particulate matter (PM)
    - Elemental carbon (EC)
    - Primary organic aerosol (POA)
    - Fine crustal PM (FCRS)
    - Fine other primary PM (FPRM)
    - Coarse crustal PM (CCRS)
    - Coarse other primary PM (CPRM)

PSAT performs PM source apportionment for each user defined source group. A source group consists of a combination of geographic regions and emissions source categories. Examples of source regions include states, nonattainment areas, and counties, whereas examples of source categories include mobile sources, biogenic sources, elevated point sources and even an individual source. The user defines a geographic source region map to specify the source regions. The user then inputs each separate source category as separate gridded low-level emission and/or elevated point source emission inputs. The model then determines each source group by overlaying the source categories on top of the source region map.

The PSAT "reactive tracers" that are added for each source category/region (*i*) are described below. In general, a single tracer can track primary PM species whereas secondary PM species require several tracers to track the relationship between gaseous precursors and the resulting PM. Particulate nitrate and secondary organics are the most complex species to apportion because the emitted precursor gases (NO, VOCs) are several steps removed from the resulting PM species (NO_3, SOA). The PSAT tracers for each type of PM are listed below. The PSAT convention is that tracer names for particulate species begin with the letter "P."

Sulfur

$SO2_i$	Primary SO_2 emissions
$PS4_i$	Particulate sulfate ion from primary emissions plus secondarily formed sulfate

Nitrogen

RGN_i	Reactive gaseous nitrogen including primary NOx (NO + NO_2) emissions plus nitrate radical (NO_3), nitrous acid (HONO) and dinitrogen pentoxide (N_2O_5).
TPN_i	Gaseous peroxyl acetyl nitrate (PAN) plus peroxy nitric acid (PNA)
NTR_i	Organic nitrates (RNO_3)
$HN3_i$	Gaseous nitric acid (HNO_3)
$PN3_i$	Particulate nitrate ion from primary emissions plus secondarily formed nitrate
$NH3_i$	Gaseous ammonia (NH_3)
$PN4_i$	Particulate ammonium (NH_4)

Secondary Organic Aerosol

ALK$_i$	Alkane/Paraffin secondary organic aerosol precursors
ARO$_i$	Aromatic (toluene and xylene) secondary organic aerosol precursors
CRE$_i$	Cresol secondary organic aerosol precursors
TRP$_i$	Biogenic olefin (terpene) secondary organic aerosol precursors
CG1$_i$	Condensable gases from toluene and xylene reactions (low volatility)
CG2$_i$	Condensable gases from toluene and xylene reactions (high volatility)
CG3$_i$	Condensable gases from alkane reactions
CG4$_i$	Condensable gases from terpene reactions
CG5$_i$	Condensable gases from cresol reactions
PO1$_i$	Particulate organic aerosol associated with CG1
PO2$_i$	Particulate organic aerosol associated with CG2
PO3$_i$	Particulate organic aerosol associated with CG3
PO4$_i$	Particulate organic aerosol associated with CG4
PO5$_i$	Particulate organic aerosol associated with CG5

Mercury

HG0$_i$	Elemental Mercury vapor
HG2$_i$	Reactive gaseous Mercury vapor
PHG$_i$	Particulate Mercury

Primary Particulate Matter

PEC$_i$	Primary Elemental Carbon
POA$_i$	Primary Organic Aerosol
PFC$_i$	Fine Crustal PM
PFN$_i$	Other Fine Particulate
PCC$_i$	Coarse Crustal PM
PCS$_i$	Other Coarse Particulate

PSAT includes a total of 32 tracers for each source group (*i*) if source apportionment is applied to all types of PM. Since source apportionment may not always be needed for all species, the PSAT implementation is flexible and allows source apportionment for any or all of the chemical classes in each CAMx simulation (i.e. the SO_4, NO_3, NH_4, SOA, Hg and primary PM classes listed above). For example, source apportionment for sulfate/nitrate/ammonium requires just nine tracers per source group.

One fundamental assumption in PSAT is that PM is apportioned to the primary precursor for each type of PM. For example, SO_4 is apportioned to SOx emissions, NO_3 is apportioned to NOx emissions, NH_4 is apportioned to NH_3 emissions, etc. As a source apportionment method, PSAT must account for all modeled sources of a PM species. Consider two model species A and B that are apportioned by reactive tracers a_i and b_i, respectively. Reactive tracers must be included for all sources of *A* and *B* including emissions, initial conditions and boundary conditions so that complete source apportionment is obtained, i.e., $A = \Sigma a_i$ and $B = \Sigma b_i$.

In PSAT, the general approach to modeling change over a model time step Δt is illustrated for a chemical reaction $A \rightarrow B$. The general equation for species destruction is:

$$a_i(t + \Delta t) \quad = \quad a_i(t) + \Delta A \frac{a_i}{\sum a_i}$$

Here, the relative apportionment of *A* is preserved as the total amount changes. This equation applies to chemical removal of *A* and also to physical removal of *A* by processes such as deposition or transport out of a specific grid cell.

The general equation for species production (e.g., chemical production by the chemical reaction $A \rightarrow B$ is:

$$b_i(t+\Delta t) \quad = \quad b_i(t) + \Delta B \frac{a_i}{\sum a_i}$$

Here, production of *B* inherits the apportionment of the precursor *A*. The same equation applies for "production" of *B* in a specific grid cell due to emissions or transport. For the case where *B* increases due to emissions, a_i is the apportionment of the emissions inventory. For the case where *B* increases due to transport, a_i is the apportionment of the upwind grid cell.

In some cases, source category specific weighting factors (w_i) must be added to the equation for species destruction:

$$a_i(t+\Delta t) \quad = \quad a_i(t) + \Delta A \frac{w_i a_i}{\sum w_i a_i}$$

An example is chemical decay of the aromatic volatile organic compound (VOC) tracers (ARO), which must be weighted by the average hydroxyl radical (OH) rate constant of each ARO_i. ARO tracers for different source groups have different average VOC reactivities because the relative amounts of toluenes and xylenes differ between source categories.

In some cases, source category specific weighting factors (w_i) must be added to the equation for species production:

$$b_i(t+\Delta t) \quad = \quad b_i(t) + \Delta B \frac{w_i a_i}{\sum w_i a_i}$$

An example is chemical production of condensable gases (CG1 or CG2) from aromatic VOC tracers, which must be weighted by aerosol yield weighting factors. The aerosol yield weighting factors depend upon the relative amounts of toluenes and xylenes in each source group.

Several aerosol reactions are treated as equilibria, $A \leftrightarrow B$. If *A* and *B* reach equilibrium at each time step, it follows that their source apportionments also reach equilibrium:

$$a_i(t+\Delta t) \quad = \quad [a_i(t)+b_i(t)]\left(\frac{A}{A+B}\right)$$

$$b_i(t+\Delta t) \quad = \quad [a_i(t)+b_i(t)]\left(\frac{B}{A+B}\right)$$

Examples are the equilibrium between gas phase nitric acid and aerosol nitrate, gas phase ammonium and aerosol ammonium, and condensable organic gases (CG) and secondary organic aerosols (SOA).

The PSAT source apportionment technique has been extensively tested and evaluated against other source apportionment techniques (e.g., ENVIRON, 2005; Morris et al., 2005; Yarwood et al., 2004).

Updates to the PSAT Formulation

The CAMx PSAT and PiG algorithms were updated to treat the near-source chemistry of secondary PM formation and to be compatible with each other. The PiG module now treats full-science aerosol chemistry and dynamics in addition to gas-phase chemistry and has been extended to PSAT and Ozone Source Apportionment Technology (OSAT.) The formulation of the full-science PiG is described below.

Modeling photochemistry is a highly non-linear problem because chemical rates for most compounds depend upon their ambient concentrations. Ambient concentrations in turn depend on how well the modeling grid resolves emissions, transport, and chemical history. Thus, grid resolution plays a vital role in the ability of the model to properly characterize photochemical conditions. Increasing resolution should, in theory, lead to a better model as the time/space discretization tends toward a continuum. However, practical and theoretical considerations suggest that the lower limit on horizontal grid spacing is approximately 1000 meters for Eulerian air quality models such as CAMx, although grid spacing on the order of a 100 m has been used . Nevertheless, even higher resolution is often necessary to adequately simulate chemistry within concentrated point source plumes.

As a result, many modern Eulerian models contain a PiG sub-model that tracks individual plume segments (or puffs) in a Lagrangian sense, accounting for plume-scale dispersion and chemical evolution, until such time as puff mass can be adequately represented within the larger grid model framework. It is important to understand that the inclusion of a Lagrangian puff model within an Eulerian grid model is a forced construct. The formulations of the two modeling approaches are fundamentally different and there is no theoretically “correct” methodology. This explains the variety of PiG methodologies that are in use today. The CAMx PiG module was recently updated in Version 4.4 of the model.

The new PiG approach in CAMx treats the full suite of gas-phase photochemistry, aqueous-phase chemistry and aerosol phase chemistry and dynamics. Chemical processes are simulated within each plume segment using an “incremental chemistry” approach, whereby puffs carry the incremental contributions of the puff relative to the grid concentrations. Incremental puff concentrations can be positive or negative, depending upon the species and stage of plume evolution. A similar chemistry approach is used in the Second-order Closure Integrated puff model (SCIPUFF) with CHEMistry (SCICHEM) Lagrangian model (EPRI, 2000). The approach lends itself to incorporating chemistry for particulates as well.

Basic Puff Structure and Diffusive Growth

The CAMx PiG releases a stream of plume segments (puffs) from a point source specified in the CAMx input file by setting the point source stack diameter to a negative value. Each puff possesses a longitudinal length and directional orientation defined by the separation of a leading and a trailing point. Initial separation of these points is determined by the wind vector at final plume rise. Each point is then subsequently and independently transported through the gridded wind fields, which directly accounts for puff stretching and changes to centerline orientation due to deforming shears. The official "position" of each puff is defined by the center point of each puff between the endpoints. This position defines the grid cell in which the puff resides for the calculation of diffusion and chemistry.

Like other puff models, the shape of each puff is characterized by a spread tensor, which is defined from a set of Gaussian standard deviations (so-called "sigmas") along the three spatial axes (σ_x, σ_y, σ_z). Diffusive growth is defined by the growth in these sigma values. The total cross-sectional width extends $\pm 1.5\sigma$ from puff centerline. The limits of $\pm 1.5\sigma$ result in an average concentration across the Gaussian distribution that nearly equals a uniformly mixed concentration across that distance. The total longitudinal length is the distance between the puff endpoints $\pm 1.5\sigma_y$. Horizontal area is calculated using the formula for an ellipse. Different vertical constructs are employed for Greatly Reduced and Simplified Dynamics (GREASD) and Incremental Reactions for Organics and NO_x (IRON) PiG, as described later in this section. Figure 2-4 presents a schematic representation of each puff in horizontal cross-section.

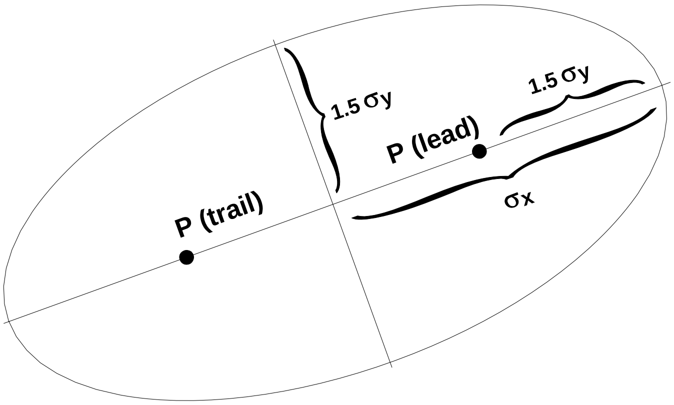


Figure 2-4. Schematic representation of CAMx PiG puff shape in the horizontal. Directional orientation of the puff is arbitrary, and evolves during the aging of the puff according to wind direction, shears and diffusive growth along its trajectory.

We have developed an explicit solution approach for puff growth that shares SCICHEM theory and concepts (EPRI, 2000), but includes some simplifications. SCICHEM solves predictive spatial moment equations with second-order closure that relate the evolution of the puff spread tensor ($\sigma_{ij}=\sigma_i \times \sigma_j$) to resolved mean shears and turbulent velocity statistics. The Reynolds-averaged second-moment transport equation is given as:

$$\frac{d\sigma_{ij}}{dt} = \sigma_{ik}\frac{\partial \overline{u}_j}{\partial x_k} + \sigma_{jk}\frac{\partial \overline{u}_i}{\partial x_k} + \frac{\left\langle x_i' \overline{u_j' c'} \right\rangle}{Q} + \frac{\left\langle x_j' \overline{u_i' c'} \right\rangle}{Q}$$

where $\overline{u}$ is the mean wind vector component, the primed values represent turbulent fluctuations from the mean, and the angle brackets denote integrals over space. The Reynolds averaging process always introduces higher-order fluctuation correlations, and this is given by the turbulent flux moments $\left\langle x'\overline{u'c'} \right\rangle$, where $\overline{u'c'}$ represents the turbulent flux of concentration. It is these last two diffusion terms that SCICHEM solves in its second-order closer scheme.

For sub-puff scale turbulence, SCICHEM employs the restriction that the only off-diagonal component of $\left\langle x'\overline{u'c'}\right\rangle$ to be considered is the symmetric horizontal term (i=x, j=y), and then only for the large-scale (meso to synoptic) contribution to puff deformation when puff scale reaches such dimensions. In CAMx, we ignore this off-diagonal flux moment term altogether since puff mass is ultimately introduced to the grid when puff size is at the grid scale (1-50 km in practically all applications), and thus puffs never reach spatial scales at which this term becomes important. SCICHEM also makes the assumption that the horizontal turbulence is isotropic, $\left\langle x'\overline{u'c'}\right\rangle = \left\langle y'\overline{v'c'}\right\rangle$. This results in a single diffusivity equation for both x and y directions, and a single diffusivity for the z direction:

$$K_x = K_y = \frac{\left\langle y'\overline{v'c'}\right\rangle}{Q}$$

$$K_z = \frac{\left\langle z'\overline{w'c'}\right\rangle}{Q}$$

In our approach for CAMx, we have adopted the SCICHEM second-order tendency equations to model the time-evolution of puff turbulent flux moments (represented by diffusivities K_x=K_y and K_z) and their contribution to the evolution of puff spread (represented by the diagonal components of the puff spread tensor, $\sigma_x^2 = \sigma_y^2$ and σ_z^2). The off-diagonal contributions to puff spread are ignored, because they are unnecessary in the context of the CAMx PiG. Puff spread is defined for puff depth (σ_z) and puff width (σ_y); the latter is also added to the longitudinal length to allow for diffusive growth along the puff centerline. We account for the effects of wind shears in the evolution of lateral spread, but assume that the evolution of vertical spread is solely the result of turbulent fluxes.

The resulting two Reynolds-averaged second-moment transport equations for CAMx PiG are

$$\frac{d\sigma_z^2}{dt} = 2K_z$$

$$\frac{d\sigma_y^2}{dt} = 2\sigma_y^2 D + 2\sigma_y\sigma_z\left(\frac{du}{dz}^2 + \frac{dv}{dz}^2\right)^{1/2} + 2K_y$$

where D is deformation of horizontal wind (see Section 2).

The SCICHEM tendency equation for the horizontal turbulent flux moment is:

$$\frac{d}{dt}\left\langle y'\overline{v'c'}\right\rangle = Qq^2 - A\frac{q}{\Lambda}\left\langle y'\overline{v'c'}\right\rangle$$

where A = 0.75, $q^2 = \overline{v'v'}$, and Λ is the horizontal turbulent length scale. Separate equations are given for two different boundary layer turbulence scales (shear- and buoyancy-produced), such that:

$$\left\langle y'\overline{v'c'}\right\rangle = \left\langle y'\overline{v'c'}\right\rangle_{shear} + \left\langle y'\overline{v'c'}\right\rangle_{buoyancy}$$

Within the surface-based boundary layer, the horizontal velocity variance is given by:

$$q^2_{buoyancy} = 0.13\, w_*^2 \left[1 + 1.5 \exp(z / z_i)\right]$$

$$q^2_{shear} = 2.5 u_*^2 (1 - z / z_i)$$

where u_* is the friction velocity, w_* is the convective velocity scale, z is height above the surface, and z_i is the height of the surface-based boundary layer. The horizontal turbulent length scale is given by:

$$\frac{1}{\Lambda^2_{shear}} = \frac{1}{(0.3\, z_i)^2} + \frac{1}{(0.65\, z)^2}$$

$$\Lambda_{buoyancy} = 0.3\, z_i$$

In the stable boundary layer, only the shear components of q^2 and Λ are applied. Above the boundary layer, SCICHEM applies rough approximations for the velocity variance and turbulent length scale: $q^2 = 0.25$ m^2/s^2, and $\Lambda = 1000$ m.

The SCICHEM tendency equation for the vertical turbulent flux moment is

$$\frac{d}{dt}\left\langle z'\overline{w'c'}\right\rangle = A \frac{q_v}{\Lambda_v}\left(Q K_z^{eq} - \left\langle z'\overline{w'c'}\right\rangle\right)$$

where $q_v^2 = \overline{w'w'}$, Λ_v is the vertical turbulent length scale, and K_z^{eq} is the equilibrium diffusivity. Whereas a specific equation for K_z^{eq} is formulated for SCICHEM, we have chosen to specify the value of this parameter from the gridded fields of vertical diffusivity in CAMx. Again SCICHEM gives separate equations for shear- and buoyancy-produced turbulence scales.

Within the surface-based boundary layer, the vertical velocity variance is given by

$$q_v^2\Big|_{shear} = 1.5\, u_*^2 (1 - z / z_i)$$

$$q_v^2\Big|_{buoyancy} = 1.1\, w_*^2 (z / z_i)^{2/3} (1.05 - z / z_i)$$

The vertical turbulent length scale for both shear and buoyancy is equal to Λ_{shear} given above for horizontal length scale. Above the boundary layer, SCICHEM again applies rough approximations for the velocity variance and turbulent length scale:

$q_v^2 = 0.01$ m^2/s^2, and $\Lambda_v = 10$ m.

The external variables needed by IRON PiG to complete the dispersion calculations include z_i, u_* and w_*. All of these are available from an internal module in CAMx that calculates these boundary layer similarity theory parameters. Thus, no additional parameters are needed to be input to the model.

Puff Transport

A fresh set of new puffs are released from all PiG point sources within the modeling domain for the duration of the smallest time step among the master and all nested grids. The length of each puff is determined by the combination of the mean total wind speed at the height of final plume rise and time step. Limits are placed on maximum extruded length based on half the finest resolution in the given simulation. If winds and time-steps are such that the maximum allowed length is violated, then several puffs are extruded from a given stack per time step. The orientation of the puff length is along the total wind vector. Total puff volume is determined by stack volumetric flow rate in conjunction with growth due to turbulent entrainment following the SCICHEM approach. Initial σ_y and σ_z are explicitly calculated from this entrainment calculation.

Effects of wind divergence on plume deformation are treated in an explicit manner within the CAMx PiG using a "chained puff" approach (Figure 2-4). Points at the leading and trailing edges of the puff centerline are individually transported through the gridded wind fields, which directly accounts for puff stretching and changes to centerline orientation due to deforming shears. Since PiG puffs can extend over multiple layers, layer density-weighted average wind components are determined for each endpoint based on the vertical coverage of the puff, and these are used for advection of those points. PiG puffs are not allowed to expand beyond the depth of the layer in which the centerpoint resides, so only the single layer wind components are used to advect the endpoints.

The "chain" aspect means that at least initially (as puffs are extruded from the stack) the trailing point of a puff emitted at time *t* will be the leading point of a puff emitted at time *t+dt*. However, as the puffs are advected downstream, the leading point of one puff will deviate from the trailing point the puff behind it due to evolving puff depth and wind fields. Puff volume is conserved in convergent/divergent wind fields. Puff endpoints may move closer together or further apart, in wind fields that are slowing or accelerating downstream. We compute puff end-point separation changes and then adjust puff widths and depths to maintain constant puff volume. The change in computed puff endpoint spacing defines puff length tendencies, then puff depth tendencies are computed from grid-resolved vertical wind shear (*dw/dz*), and finally we determine the puff width tendencies required to conserve puff volume.

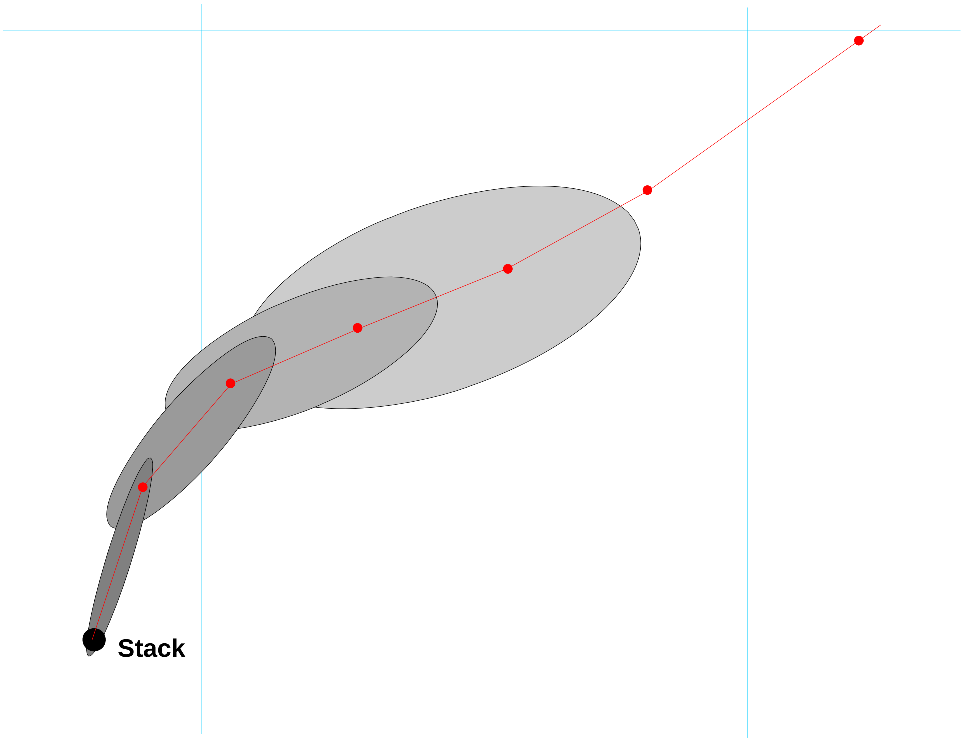


Figure 2-5. Schematic representation of a chain of PiG puffs emitted from a point source into an evolving gridded wind field. The red line connected by dots represents puff centerlines, with dots representing leading and trailing points of each puff. The CAMx computational grid is denoted by the blue lines.

The official "position" of each puff is defined by the center point of each puff between the endpoints. This position defines which grid domain and grid cell the puff resides for the calculation of diffusion and chemistry. This definition holds even if the puff is sufficiently long that the endpoints are in different grid cells (or even different grid domains if near a domain boundary). With our definition for termination when horizontal area approaches grid cell area, the extents of the puff length should not extend across more than two grid cells.

PiG Chemistry

The primary goal of the new PiG formulation in CAMx Version 4.4 was to include a more complete treatment of chemistry in point source pollutant plumes, while secondarily improving puff-grid mass exchange and adding additional features central for treating toxic pollutants not normally carried by the standard CAMx chemical mechanisms. Several approaches have been developed to treat photochemistry within point source plume models. One of the more elegant methodologies is the incremental chemistry idea embodied in the SCICHEM model (EPRI, 2000). However, we found that the implementation of incremental chemistry in SCICHEM is very complex, especially in its handling of the chemistry of overlapping puffs. In adopting this innovative approach for the new PiG, it was necessary to reformulate the physical and chemical configuration of the PiG puffs and to utilize an accurate numerical solution approach based on the Livermore Solver for Ordinary Differential Equations (LSODE) chemical solver.

The Concept of Incremental Chemistry

For a second-order reaction between puff species *A* and *B*, the total reaction rate is the following:

$$R_T = k(P_A)(P_B) \tag{1}$$

where P_A and P_B are the total puff concentrations of each species. The total puff concentrations can be expressed as the sum of the background and puff perturbation concentrations:

$$P_A = (c_A + C_A)$$

$$P_B = (c_B + C_B)$$

where C is the ambient concentration and c is the puff increment concentration. Thus the reaction rate is found to be:

$$R_T = k(c_A + C_A)(c_B + C_B)$$

or

$$R_T = k(c_A c_B + C_A c_B + c_A C_B + C_A C_B)$$

If we subtract the rate of change of the background,

$$R_{Ambient} = kC_A C_B \tag{2}$$

by assuming that it is explicitly and separately treated by the grid model, we obtain the reaction rate for the puff increments:

$$R_P = k(c_A c_B + C_A c_B + c_A C_B) \tag{3}$$

Equation 3 is the basis of SCICHEM incremental chemical kinetic solver. One problem with this approach is the mixed terms, $C_A c_B$ and $c_A C_B$. Most chemical solver packages are designed to solve rate equations for total concentration, as in Equation 1. Thus, for the new PiG we developed an alternative numerical solution scheme for puff perturbation chemistry. We note that the CAMx chemical solver can be independently applied to the rate equation for total puff concentrations, Equation 1, and to the rate equation for ambient concentrations, Equation 2. By subtraction of the two solutions, we obtain the solution to rate Equation 3. This requires no modification to, and is obviously completely self-consistent with, the CAMx chemical solvers. Once the incremental puff reaction rates are obtained they are applied to the incremental puff mass to calculate the new (adjusted for chemistry) incremental concentrations. These new puff increments are subsequently advected and dispersed by the transport portions of the PiG code.

Puff Constructs for Incremental Chemistry

The new PiG sub-model includes three new constructs designed specifically to facilitate the incremental chemistry approach:

- Treatments to handle puff-grid information exchange for puffs spanning multiple model layers;
- The concept of “virtual dumping” to handle the chemical impacts of large puffs that can overlap other puffs within a given grid column; and

- The concept of multiple puff "reactor" cells to account for the chemical effects of concentration distributions within each puff.

Each of these is described below.

Puff Layer Spanning

The new PiG is designed to chemically process point source plume mass within streams of puffs until such time that each puff can be adequately resolved on the *horizontal* grid. Unlike the previous versions of the PiG approach, where the vertical layer structure dictates puff leaking and ultimately termination, the approach in new PiG leads to the necessity that puffs be allowed to vertically span multiple grid model layers before they reach horizontal grid scales. This introduces technical implications for defining "background" concentrations and ambient conditions for puff chemistry, as well as for transferring plume incremental mass to the grid. The solution employed in the new PiG is to:

1) Assume that the vertical distribution of puff concentration is always uniform;

2) Distribute puff mass transfer (via "leaking" and "dumping") to the grid according to the puff fractional coverage across each model layer and by density-weighting; and

3) Determine mean background concentrations and other ambient conditions (e.g., temperature, humidity, etc.) over the puff vertical span via similar fractional layer-density weighting.

PiG puffs are considered to be elliptical in the horizontal, with the minor axis spanning the cross-wind puff width (defined as $\pm 1.5\sigma_y$), and the major axis spanning the along-wind puff length (defined as length $\pm 1.5\sigma_y$ on each end). This is similar to GREASD PiG. However, given the complications associated with multiple layer spanning and mass-weighting of ambient inputs and dumped mass, puffs are rectangular and uniform in the vertical, with total puff depth defined as $\pm 1.5\sigma_z$.

Horizontally, the mean background concentration and ambient conditions are taken from the single host grid column containing each puff center point, even if the puff is large and/or spans a horizontal cell interface.

Chemistry Solution

In summary, chemistry is solved for each PiG puff "reactor" in three steps:

1) The layer-mean background (grid + overlapping puff) concentrations and environmental conditions over the volume occupied by the puff are stored and then chemically updated via the LSODE gas-phase chemistry mechanism;
2) The pre-updated mean background concentrations are added to the puff increments and the total concentrations are chemically updated; and

3) The updated results from step 1 are subtracted from the updated results of step 2 to provide the updated incremental concentrations.

An important consequence of this approach is that the incremental puff mass may be positive or negative. For example, a high- NO_x puff that is destroying ambient ozone will have negative ozone increments. The puff increments are subsequently advected and dispersed by the transport portions of the IRON PiG code. The updated background concentrations, which include "virtual dumps" of mass from large puffs, are used for reference only in the puff incremental chemistry algorithm; the actual grid concentrations are updated in the grid chemistry routine.

Puff Dumping and PiG Rendering

Mass transfer from puff to grid can happen in two ways: slowly, termed "leaking," or suddenly, termed "dumping." As described earlier, all mass is transferred from the PiG to the vertical grid structure in a density-weighted fashion according to each puff's fractional layer coverage. The process of leaking ensures that puff mass is transferred to the grid continuously, rather than in discrete lumps of pollutants with very different concentrations than those in the grid. The idea behind puff leakage is to account for turbulent shearing of mass from the main plume and its subsequent dispersion to the grid scale. This rate of transfer should be directly proportional to the puff size relative to the grid scale. The user can control whether a puff is leaked or not, and for Arkansas BART cumulative modeling, we assumed the default mode in which puffs are not leaked to the grid. This will allow the full-science PiG plume model to treat the chemistry of the BART point source plumes as plume chemistry until either: (1) the plume reaches chemical maturity; or (2) the plume size is commensurate to the grid cell size.

While the mass confined to the puffs at any given time has not yet affected the grid concentrations, it will eventually, so it can be somewhat misleading to sequester this mass from visualizations of a model simulation. The puff mass can be optionally incorporated into the model average output files for visualization purposes (referred to as "PiG rendering"). Rendering employs a "virtual dump" of the puff masses into the average concentration array each time step. As described for chemistry, virtual puff mass is added as an increment over the entire grid column according to fractional layer-density weighting over puff depth, thus diluting its concentrations relative to that within the puff. The actual mass of the puff stays within the puffs over the course of their lifetimes. This visualization is available for 3-D average output files, and can produce some rather startling effects in output displays, including very narrow virtual plumes, or streaks, representing mass moving through the grid in sub-grid puffs, but not subject to grid-scale eddy diffusion.

High Resolution Puff Sampling

PiG optionally employs surface-layer puff sampling of concentration species on a user-defined grid of arbitrary horizontal resolution, similarly to the way nested grids are defined. Sampling grids are entirely passive, and intended to provide a display of the plume concentrations at scales much smaller than typically used for the finest computational grids (i.e., <1 km), primarily around and downwind of a source complex. Sampled PiG concentrations are time-averaged like the output concentrations provided on the computational grids, and are written to files with similar format so that they may be readily viewed and manipulated with CAMx post-processing software.

Given that the puffs constantly evolve via diffusive growth and reshaping due to deforming shears, the sampling procedure includes trigonometric calculations to define which sampling points are influenced by each puff. This influence is determined according to the puffs' two-dimensional horizontal Gaussian shape shown in Figure 2-4. To include a sufficiently large percentage of mass across each puff for sampling, limits of $\pm 3\sigma_y$ in both horizontal dimensions are used to define the puffs' total elliptical area coverage. Puffs are only sampled if they extend vertically into the model's surface layer.

For the Arkansas cumulative BART modeling high resolution puff sampling was not used since the Class I areas are not close to any BART sources so the puffs will be released to the grid by the time they reach the Class I areas.

EMISSIONS MODELING

The starting point for generating the 2002 emissions for the Arkansas CAMx PSAT/PiG cumulative BART modeling was the CENRAP 2002 Base F emissions modeling set up. The ADEQ has provided information on 9 BART-eligible sources at 6 facilities as listed in Table 2-1.

Table 2-1 List of Arkansas BART point sources to be used in the cumulative BART modeling analysis.

Stationary Source Name/Location	ISTEPS[1] AFIN	Unit ID	Description	UTM Coordinates North (km)	UTM Coordinates East (km)
American Elect. Power (SWEPCO) / Gentry	04-00107	SN-01	Boiler	4013.449	363.123
Ark. Elect. Coop - Bailey Plant / Augusta	74-00024	SN-01	Boiler, 1350mm	3903.072	648.831
Ark. Elect. Coop - McClellan Plant / Camden	52-00055	SN-01	Boiler	3713.898	519.310
Domtar, Inc. / Ashdown	41-00002	SN-03	#1 Power Boiler	3722.716	396.754
		SN-05	#2 Power Boiler	3722.640	396.759
Entergy - Lake Catherine / Jones Mill	30-00011	SN-03	Unit 4 Boiler	3810.324	508.781
Entergy - White Bluff / Redfield	35-00110	SN-01	Unit 1	3809.437	579.101
		SN-02	Unit 2	3809.447	579.101
		SN-05	Aux Boiler	3809.357	579.113

[1] ISTEPS; State of Arkansas Department of Environmental Quality Permitted Facility Emissions and Stack Data (www.adeq.state.ar.us/air/isteps/isteps.asp)

The procedures for performing the emissions modeling for the Arkansas cumulative BART CAMx/PSAT/PiG modeling were as follows:

- Identifying and separating of the Arkansas BART sources from the CENRAP 2002 Base F point source emissions SMOKE modeling database. Based on a review of the CENRAP emissions data base, it was determined that the CENRAP emissions database was missing the Bailey Plant and Lake Catherine emissions. Therefore, the representative records for these facilities and units were obtained from the ISTEPS data base (ISTEPS, 2007).

- Processing of the non-Arkansas BART point sources to generate a CAMx-ready point source emissions file for 2002.

- Quality Assurance (QA) of the Arkansas BART source emissions and stack parameters received from the ADEQ for the various emission scenarios (Pettyjohn, 2007a,b). The comparisons with the existing emissions and stack parameters of these sources in the CENRAP are shown in Table 2-2.

- Processing of the Arkansas BART point sources with SMOKE for the various emissions scenarios provided by ADEQ to generate CAMx-ready Arkansas BART point source emissions.

  Two sets of emissions estimates were provided: (1) base case emissions estimates (Pettyjohn, 2007b, 2007c, 2007d; Wilkinson, 2007); and (2) control case emissions estimates (Jewell et al, 2006; Cain, 2006; ENSR, 2006a, 2006b; Pettyjohn, 2007e). Table 2-3 summarizes the base case and the control case emissions rates that were used in the air quality modeling study. These emissions represent the maximum emissions rate over each day in the year; except for Lake Catherine where the emissions for natural gas are for spring, summer and fall days and the emissions for fuel oil are for winter days. Emissions estimates of CO and VOC are also included in the CENRAP and ISTEPS data bases, however, these emissions were used as-is in the air quality modeling study.

  Though modeling could have been conducted as if each source emitted at the rates specified in Table 2-3 twenty-four hours a day, seven days a week, this is not truly representative of the operating profiles for these units. Instead, the emissions rates were adjusted to match the diurnal profiles in the CENRAP emissions modeling database based on SCCs for more realistic conditions. Although the total 24-hour emissions matched the values in Table 2-3.

- Flagging of the Arkansas CAMx-ready point source emissions to be treated by PiG and PSAT.
  - Each Arkansas BART point source was treated as a separate PSAT source group by using the negative kcell value point source override PSAT source group identification.
  - Each Arkansas BART point source was also flagged for treatment by the PiG module by setting the diameter to its negative value.

- Merging of the Arkansas BART point source emissions with the remainder of the CENRAP 2002 Base F point source emissions for each emission scenario provided by ADEQ.

Table 2-4 lists the emission reductions by facility from the pre-control base case to the post-control BART control case.

During the modeling process, ADEQ was informed that the emissions provided by the Domtar Arkansas subject-to-BART source were incorrect and the actual maximum 24-hour emissions are higher. Due to schedule and budget restraints, the Domtar source was not rerun. To address this issue, a sensitivity analysis using the corrected Domtar emissions for the pre- and post-control scenarios was conducted and the results are presented in Section 3. The corrected Domtar emissions provided by ADEQ are shown in Table 2-5.

The Domtar emissions sensitivity analyses "corrected" the Domtar PM impacts at the Class I areas through linear scaling using the ratio of the corrected to modeled emissions on a species-by-species basis. For example, the Domtar (ISTEP=41-00002) modeled Base Case SO_4 impacts at a Class I area would be scaled by the ratio of the corrected (154.88 g/s) to modeled (70.95 g/s) SO_2 emissions resulting in a scaling factor of 2.18 for the Domtar sensitivity analysis.

Table 2-2. Comparison of stack parameters as they exist in the CENRAP emissions data base and as provided by ADEQ.

ISTEPS AFIN	Unit ID	Stack Parameters as supplied by ADEQ						Stack Parameters from CENRAP Emissions Data Base					
		Height (ft)	Diameter (ft)	Temperature (F)	Velocity (ft/s)	Lon (deg)	Lat (deg)	Height (ft)	Diameter (ft)	Temperature (F)	Velocity (ft/s)	Lon (deg)	Lat (deg)
04-00107	SN-01	540	20	275	112	-94.5236	36.2563	540	20	275	65.96	-94.4777	36.2382
74-00024	SN-01	167	9.83	340	92	-91.3639	35.2597	*no data exists for this facility in the CENRAP emissions data base*					
52-00055	SN-01	160	10.83	340	92	-92.7919	33.5646	160	10.83	261	47.93	-92.7933	33.5636
41-00002	SN-03	217	6.2	480	87.8	-94.1133	33.6393	217	6.2	480	87.8	-94.1127	33.6391
	SN-05	235	12	125	39.1	-94.1133	33.6386	250	12	340.4	39.1	-94.1134	33.6391
30-00011	SN-03	195	17	254	10.1	-92.9044	34.4344	*no data exists for this facility in the CENRAP emissions data base*					
35-00110	SN-01	1000	25.7	321	90	-92.1392	34.4234	1000	25.7	321	90	-92.1402	34.4392
	SN-02	1000	25.7	321	90	-92.1392	34.4235	1000	25.7	321	90	-92.1402	34.4392
	SN-05	15	3	475	65	-92.1392	34.4226	10	0.003	72	0.0003	-92.1402	34.4392

Table 2-3. Base case and Control case emissions rates for Arkansas Subject-to-BART units.

ISTEPS Plant ID	Unit ID	Fuel	Base Case				Control Case			
			SO2 (g/sec)	NOX (g/sec)	PM10 (g/sec)	PM2.5 (g/sec)	SO2 (g/sec)	NOX (g/sec)	PM10 (g/sec)	PM2.5 (g/sec)
04-00107	SN-01		595.78	245.07	12.79	5.53	119.52	183.27	12.79	5.53
74-00024	SN-01		299.34	36.93	21.73	21.73	130.42	36.93	21.73	21.73
52-00055	SN-01		346.19	47.12	28.76	28.76	123.9	47.12	28.76	28.76
41-00002	SN-03		0.77	22.62	21.35	21.35	0.77	22.62	5.12	5.12
	SN-05		70.18	52.01	7.88	7.88	70.18	36.41	7.23	7.23
30-00011	SN-03	natural gas	0.42	309.53	4.64	4.64	0.42	35.33	4.64	4.64
		fuel oil	664.89	316.43	50.12	35.75	146.54	143.81	15.37	10.96
35-00110	SN-01		978.16	550.82	15.59	11.8	176.5	170.49	15.59	11.8
	SN-02		985.93	596.08	16.65	12.91	193.18	184.49	16.65	12.91
	SN-05		4.1	3.81	0.37	0.25	0.47	0.44	0.04	0.03

Table 2-4. Percent emission reductions between the pre-control base case and post-control case for each of the six Arkansas subject-to-BART facilities.

ISTEPS Plant ID	Plant Name	SO2 (%)	NOx (%)	PM10 (%)	PM2.5 (%)
04-00107	American Electric Power – Gentry Plant	80%	25%	0%	0%
74-00024	Arkansas Electric Cooperative —Bailey Plant	56%	0%	0%	0%
52-00055	Arkansas Electric Coop. McClellan Plant	64%	0%	0%	0%
41-00002	Domtar Inc.	0%	21%*	58%**	58%**
30-00011	Entergy – Lake Catherine (Natural Gas)	0%	89%	0%	0%
30-00011	Entergy – Lake Catherine (Fuel Oil)	78%	55%	69%	69%
35-00110	Entergy – White Bluff	81%	69%	0%	0%

* Domtar corrected NOx emissions exhibit a 22% emissions reduction from pre- to post-control cases.

** Domtar correct PM10 and PM2.5 emissions exhibit a 61% emissions reduction from pre- to post-control cases.

Table 2-5. Corrected Domtar 24-hour average maximum emissions.

ISTEPS Plant ID	Unit ID	Base Case SO2 (g/sec)	Base Case NOX (g/sec)	Base Case PM10 (g/sec)	Base Case PM2.5 (g/sec)	Control Case SO2 (g/sec)	Control Case NOX (g/sec)	Control Case PM10 (g/sec)	Control Case PM2.5 (g/sec)
41-00002	SN-03	55.57	22.62	21.35	21.35	55.57	22.62	5.12	5.12
	SN-05	99.31	66.38	10.29	10.29	99.31	46.46	7.23	7.23

3.0 CUMULATIVE BART MODELING ANALYSIS

Visibility impacts were calculated at each Class I area using 24-hour PM concentration estimates produced by Comprehensive Air-quality Model with extensions (CAMx) PM Source Apportionment Technology (PSAT) for each Arkansas BART source and at each Class I area. The maximum 24-hour PM concentrations at any receptor in the Class I area were used to represent that day's visibility impacts. Visibility impairment was calculated from the daily maximum PM concentration estimates following the procedures given in EPA's BART modeling guidance (EPA, 2005) and in the Federal Land Managers Air Quality Related Values Workgroup report (FLAG, 2000). The FLAG (2000) procedures were developed to estimate visibility impacts at Class I areas from proposed new sources as part of the Prevention of Significant Deterioration (PSD) and New Source Review (NSR) process and were adapted for BART applications. These procedures use the original[1] Interagency Monitoring of Protected Visual Environments (IMPROVE) reconstructed mass extinction equation (Malm et al., 2000), only instead of using measured PM concentrations from an IMPROVE monitor, PM concentrations from the CAMx PSAT estimates were utilized in the equation.

The IMPROVE reconstructed mass extinction equation (Malm et al., 2000) is used to estimate visibility at Class I areas using IMPROVE monitoring data and has also been used for evaluating visibility impacts at Class I areas due to new sources using modeling output of a single source or group of sources. The total light extinction due to a source (b_{source}), in units of inverse Megameters (Mm^{-1}), is assumed to be the sum of the light extinction due to the source's individual PM species concentration impacts times an extinction efficiency coefficient:

$$\mathbf{b_{source} = b_{SO4} + b_{NO3} + b_{OC} + b_{EC} + b_{soil} + b_{coarse}}$$

$$b_{SO4} = 3\,[(NH_4)_2SO_4]f(RH)$$
$$b_{NO3} = 3\,[NH_4NO_3]f(RH)$$
$$b_{OC} = 4\,[OMC]$$
$$b_{EC} = 10\,[EC]$$
$$b_{Soil} = 1\,[Soil]$$
$$b_{coarse} = 0.6\,[Coarse\ Mass]$$

Here f(RH) are relative humidity adjustment factors. EPA BART modeling guidance recommends that Class I area specific monthly average f(RH) values be used (EPA, 2005; 2003a), which was used in this study. The concentrations in the square brackets are in $\mu g/m^3$ and are based on the concentrations from the CAMx PSAT modeling. Although CAMx explicitly models ammonia and ammonium, the IMPROVE extinction equation assumes that SO_4 and NO_3 are completely neutralized by ammonium (this is because the IMPROVE monitors do not measure ammonium). That is, the ammonium sulfate and ammonium nitrate concentrations are obtained from the CAMx sulfate and nitrate estimates assuming they are fully neutralized by ammonium using the following equations:

$$[(NH_4)_2SO_4] = 1.375 \times [SO4]$$
$$[NH_4NO_3] = 1.290 \times [NO3]$$

---

[1] A new revised IMPROVE equation has been developed and is being used for 2018 regional haze projections, but most BART modeling is still based on the original IMPROVE equation.

Thus, the CAMx PSAT source apportionment for ammonium is actually not used and the effect of ammonium on visibility will instead be traced back to the SO_2 and NOx sources that produced SO_4 and NO_3, respectively.

The OMC in the above equation is Organic Matter Carbon. When using IMPROVE measurements that measure Organic Carbon (OC), the original IMPROVE extinction equation assumed an OMC/OC ratio of 1.4 (i.e., the IMPROVE OC measurement is multiplied by 1.4 to obtain OMC). Since CAMx directly models OMC, the 1.4 factor is not needed. The following species mappings were used to map the CAMx species to those used in the IMPROVE reconstructed mass extinction equation given above:

$$
\begin{aligned}
[(NH_4)_2SO_4] &= 1.375 \text{ x PSO4} \\
[NH_4NO_3] &= 1.290 \text{ x PNO3} \\
[\text{OMC}] &= \text{POA + SOA1 + SOA2 + SOA3 + SOA4} \\
[\text{EC}] &= \text{PEC} \\
[\text{Soil}] &= \text{FPRM + FCRS} \\
[\text{Coarse Mass}] &= \text{CPRM + CCRS}
\end{aligned}
$$

Here PSO4 and PNO3 are the CAMx particulate sulfate and nitrate species. POA is the CAMx primary Particulate Organic Aerosol species, whereas SOA1-4 is the four Secondary Organic Aerosol species carried in CAMx. Note that for the Arkansas BART modeling, VOC emissions were not included, thus there were no contributions due to the SOA1-4 species in the above equation.[2] Primary Elemental Carbon is represented by PEC in CAMx. CAMx carries two species that represent the other $PM_{2.5}$ components (i.e., fine particles that are not SO4, NO3, EC or OC), one for the crustal material (FCRS) and the other for the remainder of the primary emitted $PM_{2.5}$ species (FPRM). Similarly, CAMx carries two species to represent Coarse Mass ($PM_{2.5-10}$), one for crustal material (CCRS) and one for other coarse PM (CPRM).

The Haze Index (HI) for the source is calculated in deciviews (dv) from the source's extinction plus natural background using the following formula:

$$HI_{source} = 10 \ln[(b_{source} + b_{natural})/10]$$

The source's HI is compared against natural conditions to assess the significance of the source's visibility impact. EPA guidance lists natural conditions ($b_{natural}$) by Class I areas in terms of extinction in units of Mm^{-1} (EPA, 2003b) and assumes clean conditions with no man-made or weather interference. EPA has defined Natural Conditions for the Best 20% days, Worst 20% days and annual average. The EPA BART guidance suggested that Natural Conditions for the Best 20% days be used (EPA, 2005). However, under challenge EPA now allows the use of annual average Natural Conditions (Paise, 2006a,b). For most BART modeling performed to date, the annual average Natural Conditions has been used. Thus, the EPA default (EPA, 2003a) annual average Natural Conditions were used in the Arkansas cumulative BART modeling.

The visibility significance metric for evaluating BART sources is the change in deciview (del-dv) from the source's and natural conditions haze indices (HIs):

---

[2] Note that CENRAP performed a VOC point source sensitivity analysis that demonstrated that the visibility impacts due to VOC emissions from all point sources did not contribute significantly to visibility impairment at any Class I area.

$$\begin{aligned} \text{del-dv} &= HI_{source} - HI_{natural} = 10\ln[(b_{source} + b_{natural})/10] - 10\ln[b_{natural}/10] \\ &= 10\ln[(b_{source} + b_{natural})/b_{natural}] \end{aligned}$$

The visibility impacts at the Class I areas of interest are given below for two emission scenarios:

- Scenario#1 pre-control actual maximum 24-hour emissions; and
- Scenario#2 post-control emissions.

Arkansas BART sources' emissions were provided by ADEQ who in turn were provided with the emission estimates from each of the Arkansas BART sources. The visibility impacts are presented first due to all Arkansas BART sources (cumulative) and pollutants, cumulative impacts are also presented separately for each visibility precursor (i.e., SOx, NOx, and primary PM emissions). The eight highest maximum visibility impacts at any Class I area are reported along with separate visibility impacts of each of the BART sources at the five primary Class I areas. The EPA BART guidance (EPA, 2005) recommends looking at the 98th percentile highest visibility impact and recommends a significance threshold for contributing to visibility impact at a Class I area of a 0.5 change in deciview (del-dv). As we are modeling one year of data (2002), then the 98th percentile corresponds to the 8th highest value. However, the Federal Land Managers (FLMs) have also requested that the maximum del-dv impact (1st highest) be used when looking at one year of data. We believe that looking at the very highest value may be misleading as it increases the likelihood that the result may be due to model uncertainties or artifacts. Thus, we present the 8 highest values and have higher confidence in the highest values that are "bunched together" rather than focus on a single day in an annual simulation.

CUMULATIVE BART MODELING RESULTS

This section presents the estimated visibility impacts at the Class I areas of interest due to all Arkansas BART sources. Note that the Domtar emissions used in the modeling analysis do not represent actual maximum 24-hour emissions as are supposed to be used in a BART analysis. The emissions provided by the Domtar source understate actual maximum 24-hour emissions and the corrected emissions were provided too late to include in the modeling. In order to address the understated Domtar source emissions, a sensitivity analysis was conducted whereby the model-estimated SO4, NO3 and primary PM concentrations impacts at the Class I areas due to the understated emissions were scaled by the ratio of the corrected to understated SOx, NOx and primary PM emissions, respectively. This scaling assumed linear relationship between PM concentration impacts and the primary precursor, which ranges from accurate for primary PM emissions to much less accurate for the NOx emissions to secondary particle NO3 impacts. The Domtar sensitivity analysis with the revised Domtar emissions is presented at the end of this chapter. Here the results are reported in terms of change of deciview (del-dv) from the sources to natural conditions haze indices ranked 1st to 8th high compared to a threshold of 0.5 and 1 del-dv. The annual average matural conditions were used as allowed by the EPA (Paize, 2006a,b). The impacts due to the total PM (thus, are based on all visibility precursors including SOx, NOx, and primary PM) of the pre-control base case, the post-control case and difference between these two scenarios are shown in Figures 3-1a, 3-1b and 3-1c, respectively.

The highest cumulative visibility impacts due to the current pre-control base case Arkansas subject-to-BART sources range from 4 to 11 del-dv (Figure 3-1a), whereas the post-control case the cumulative impacts range from 1 to 7 del-dv (Figure 3-1b). Visibility is estimated to improve significantly at all the Class I areas of interest due to the Arkansas BART controls with the greatest improvement of 5 del-dv at Mingo (MING) for the highest impact event during the year (Figure 3-1c). In fact the Arkansas BART controls reduce visibility impacts at the MING, HEGL, CACR, UPBU and WICA Class I areas by over 2 del-dv, and the controls result in reductions in the visibility impacts at all Class I areas studied by over the 0.5 del-dv significance threshold for the top 8 (top 98th percentile) impact days during 2002. However, the visibility impacts of the Arkansas subject-to-BART sources post-control case still exceed 1 del-dv at most Class I areas of interest (Figure 3-1b).

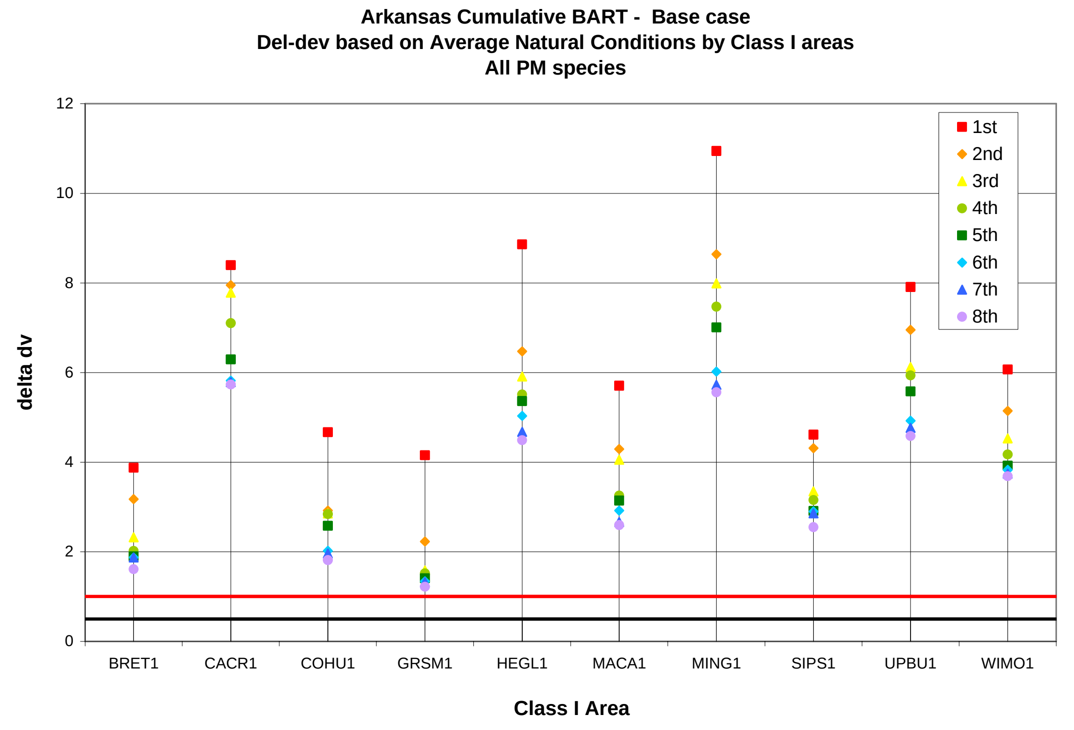


Figure 3-1a. Base case (pre-control) visibility impacts (del-dv) based on total PM from all Arkansas subject-to-BART sources. Red and black lines represent 1 del-dv and 0.5 del-dv, respectively.

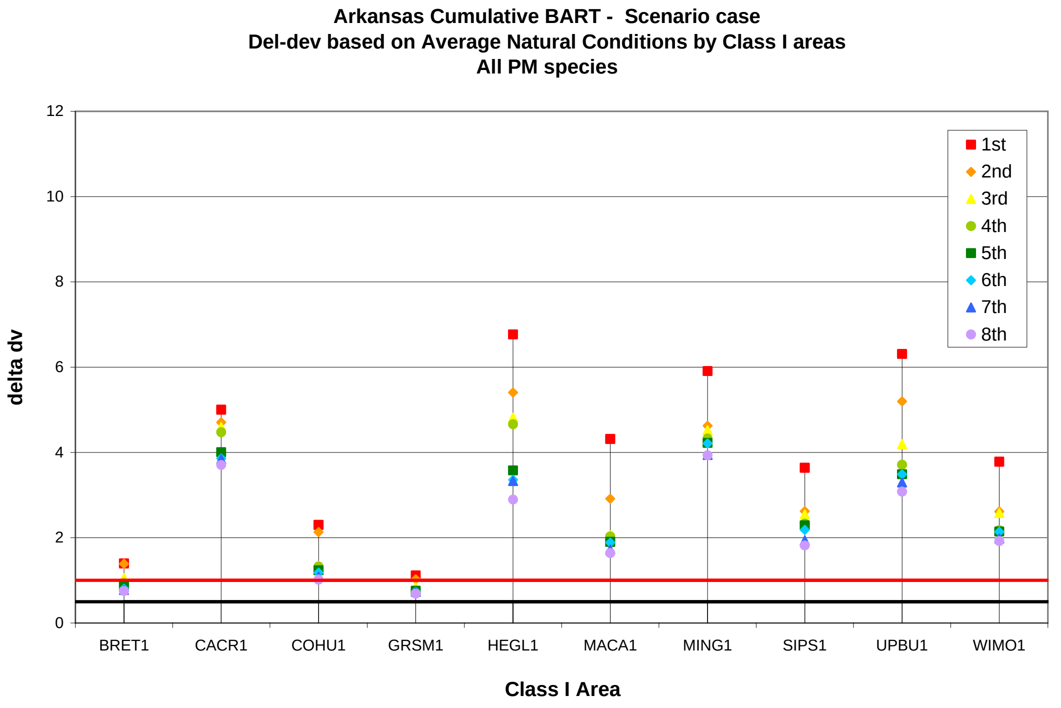


Figure 3-1b. Post-control case visibility impacts (del-dv) based on total PM from all Arkansas subject-to-BART sources.

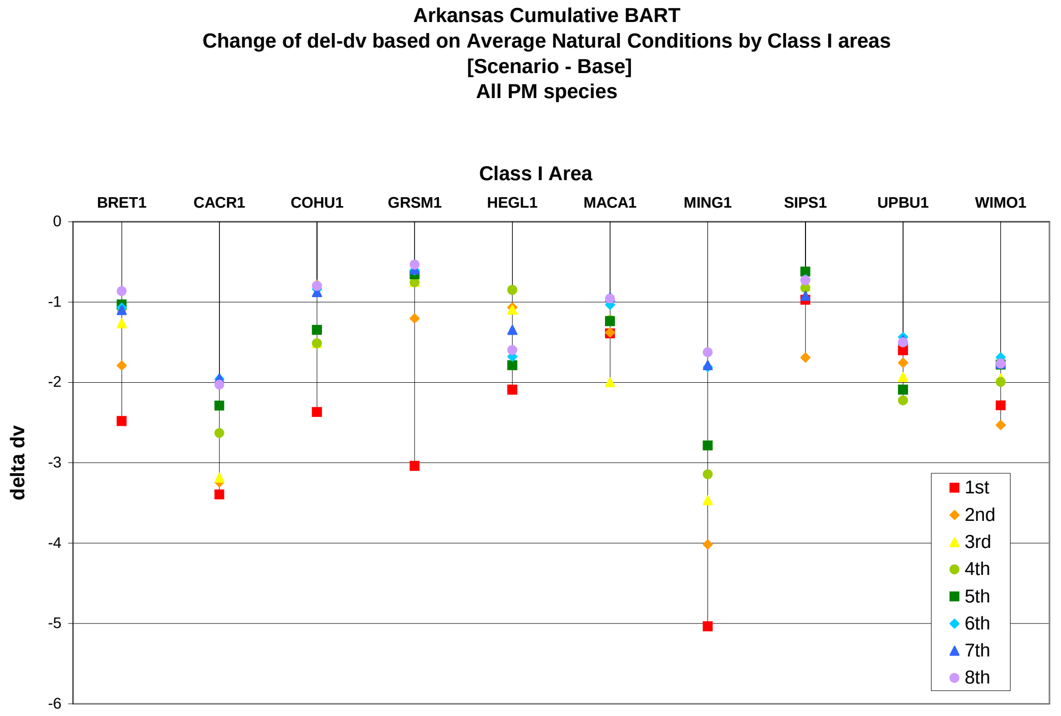


Figure 3-1c. Visibility improvement (del-dv) [post-control – base] of total PM from all Arkansas subject-to-BART sources for 8 highest impact days in 2002.

Figure 3-2 displays the Arkansas subject-to-BART sources visibility impacts due to just primary PM emissions[3], which is defined here as the sum of Organic Mass Carbon (OMC), Elemental Carbon (EC), Soil (or other $PM_{2.5}$) and Coarse Matter (CM). The Arkansas BART sources cumulative visibility impacts due to just primary PM emissions do not have a high contribution to visibility impairment at Class I areas, with most daily impacts in the pre- and post-control scenarios less than the 0.5 del-dv significance threshold. The primary PM emissions of Lake Catherine facility, which is located closest to Caney Creek (CACR), were reduced significantly. As a result, visibility improvement due to the primary PM is evident at the CACR Class I area with reductions in the 8 highest visibility impact days due to the Arkansas subject-to-BART primary PM emission controls ranging from -0.25 to -0.45 del-dv.

As shown in Table 3-1, on the days of high visibility impacts due to the Arkansas subject-to-BART sources, the impacts under the pre-control base case are dominated by sulfate (SO4), whereas under the post-control case the visibility impacts are more dominated by nitrate (NO3 or combined SO4 and NO3). SO_2 emissions are reduced significantly in the post-control case, therefore the visibility impacts decrease substantially at all Class I areas of interest (as shown in Table 3-1 and Figure 3-3). The visibility improvement due to sulfate reduction alone is as high as 6.7 del-dv at Mingo. Similar to SO_2, overall NOx emissions are considerably reduced in the post-control case but to a less extent than SO2. As shown in Figure 3-4, the visibility improvement due to nitrate alone is less than 1 del-dv. This implies that although both SO_2 and NOx emissions are reduced considerably due to the Arkansas BART controls, the visibility benefit is obtained mainly from the SO4 reduction rather than nitrate reduction. This is due to the fact that the decrease in SO4 concentrations releases ammonium (NH4) that is bound to the SO4 [$SO_4(NH_4)_2$] that allows more ammonia to become available that can become bound with nitric acid to form particle NO3 [NO_3NH_4]. This phenomena has been termed “nitrate replacement” whereby the SOx controls reduce particle SO4 but the SO4 is replaced by particle NO3. This relationship is based on sulfate-nitrate-ammonium equilibrium which is non-linear. In theory, since the reduction in SO4 can release two ammonias that have the potential to result in two particle NO3 formed nitrate replacement could result in more PM due to the SO4 reductions. However, the non-linear nature of this equilibrium typically results in smaller amounts of NO3 formed due to “nitrate replacement”.

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[3] Note that primary PM emissions also include SO4 and NO3, but those contributions are included with the impacts from PSAT SO2/SO4 and NOx/NO3 families of tracers and can not be separated without an additional simulation.

Table 3-1. Contribution of visibility degradation (del-dv) from SO_4 and NO_3 on the 8 highest visibility degradation days at Class I areas contributed by total PM from all Arkansas subject-to-BART sources.

Class I Areas	SO_4^{2-}															
	Base case del-dv								Post-control case del-dv							
	1st	2nd	3rd	4th	5th	6th	7th	8th	1st	2nd	3rd	4th	5th	6th	7th	8th
BRET1	3.8	3.2	2.3	1.8	1.9	1.8	1.8	1.6	0.0	1.4	0.2	0.1	0.3	0.8	0.5	0.0
CACR1	8.3	7.9	6.5	6.6	4.7	5.7	5.7	5.3	0.1	2.6	0.4	4.4	0.4	3.8	3.7	1.6
COHU1	4.5	0.8	2.8	2.6	0.5	2.0	0.8	1.6	0.2	0.2	1.1	0.2	0.1	0.1	0.1	0.4
GRSM1	4.1	2.2	1.3	1.5	1.4	1.3	1.3	1.2	0.0	1.0	0.1	0.2	0.1	0.3	0.1	0.0
HEGL1	4.0	1.8	2.6	5.5	2.9	0.6	4.6	4.2	1.3	0.5	0.4	0.6	0.1	1.0	0.3	0.1
MACA1	1.5	4.2	3.9	3.2	0.2	2.3	2.6	0.2	0.4	0.0	0.1	0.1	0.0	0.0	0.1	0.1
MING1	10.6	8.3	4.4	6.6	6.8	3.2	5.6	3.1	1.8	1.3	3.2	0.3	0.6	3.9	1.5	0.3
SIPS1	4.6	0.7	3.3	1.8	2.9	0.7	0.9	0.1	0.2	0.0	0.2	0.0	0.3	0.0	0.1	0.2
UPBU1	2.5	3.2	5.8	4.8	5.5	4.8	3.6	0.4	0.7	1.1	0.1	0.0	0.1	0.5	0.2	1.1
WIMO1	6.0	4.4	3.9	0.9	3.8	3.6	3.3	2.3	0.2	0.3	1.6	0.2	0.7	1.3	0.7	1.7
Class I Areas	NO_3^-															
	Base case del-dv								Post-control case del-dv							
	1st	2nd	3rd	4th	5th	6th	7th	8th	1st	2nd	3rd	4th	5th	6th	7th	8th
BRET1	0.0	0.0	0.0	0.2	0.0	0.0	0.1	0.0	1.4	0.0	0.9	0.9	0.5	0.0	0.3	0.7
CACR1	0.0	0.1	2.3	0.8	2.4	0.1	0.2	0.6	4.9	2.5	4.3	0.0	3.7	0.0	0.0	2.3
COHU1	0.2	2.3	0.0	0.3	2.1	0.1	1.3	0.2	2.2	1.9	0.2	1.1	1.1	1.1	1.0	0.7
GRSM1	0.0	0.0	0.3	0.0	0.1	0.0	0.0	0.0	1.1	0.0	0.7	0.6	0.7	0.4	0.6	0.7
HEGL1	6.5	5.4	4.1	0.0	3.1	4.6	0.1	0.5	6.0	5.1	4.5	4.2	3.5	2.6	3.1	2.8
MACA1	4.7	0.1	0.3	0.0	3.0	0.7	0.0	2.4	4.1	2.9	1.9	1.9	1.9	1.9	1.6	1.6
MING1	1.0	0.6	5.0	1.4	0.3	3.6	0.2	3.1	4.7	3.7	1.6	4.0	3.8	0.3	2.6	3.7
SIPS1	0.0	3.8	0.0	1.6	0.0	2.3	2.1	2.5	3.5	2.6	2.4	2.3	2.1	2.2	1.9	1.7
UPBU1	6.5	4.7	0.4	1.7	0.0	0.2	1.6	4.3	5.9	4.5	4.1	3.7	3.4	3.0	3.1	2.1
WIMO1	0.1	1.0	0.9	3.5	0.1	0.3	0.6	1.7	3.6	2.3	1.1	2.0	1.5	0.9	1.4	0.3

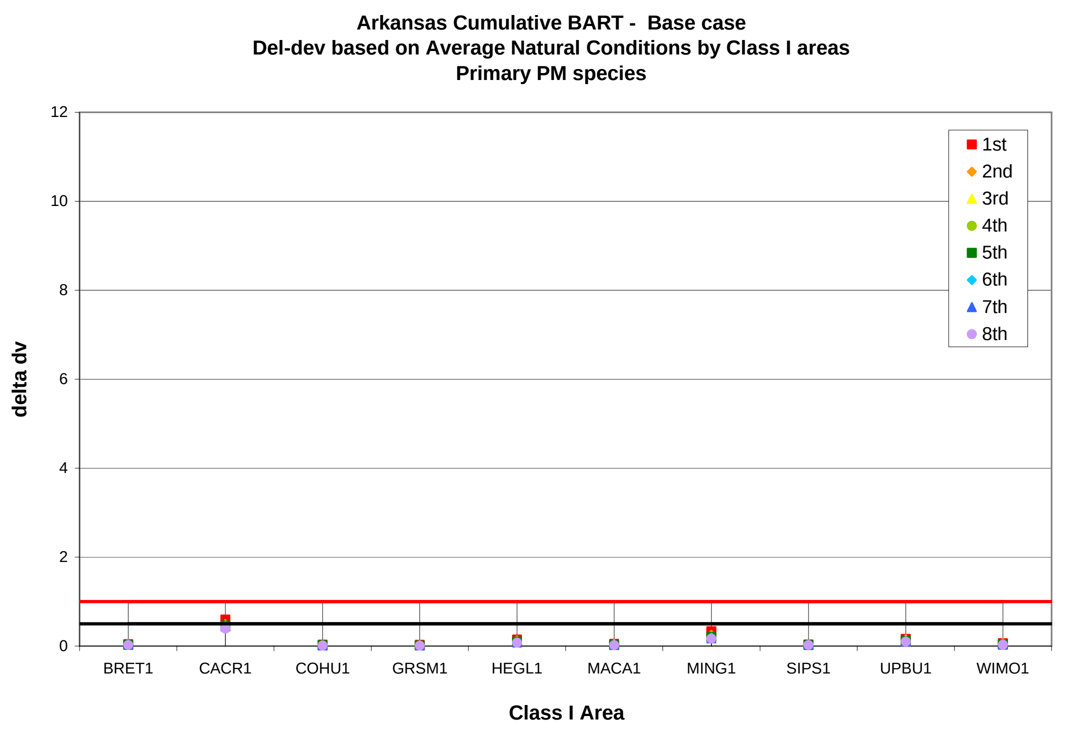

Figure 3-2a. Base case visibility impacts (del-dv) based on primary PM emissions (OMC, EC, Soil and CM) from all Arkansas subject-to-BART sources.

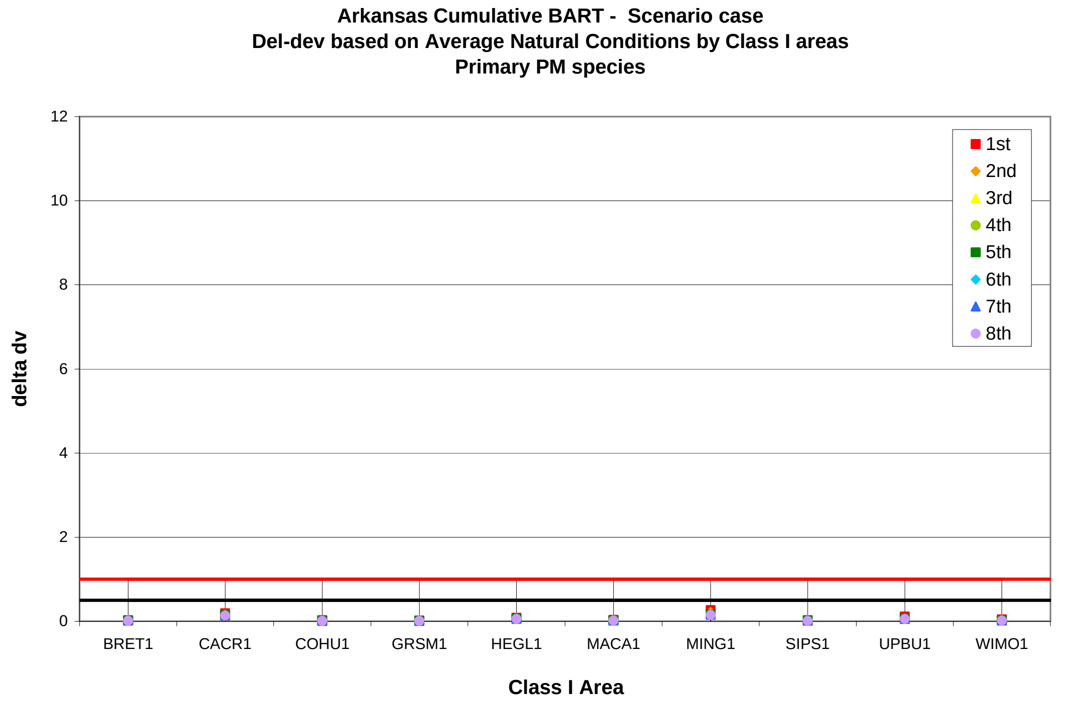

Figure 3-2b. Post-control case visibility impacts (del-dv) based on primary PM emissions (OMC, EC, Soil and CM) from all Arkansas subject-to-BART sources.

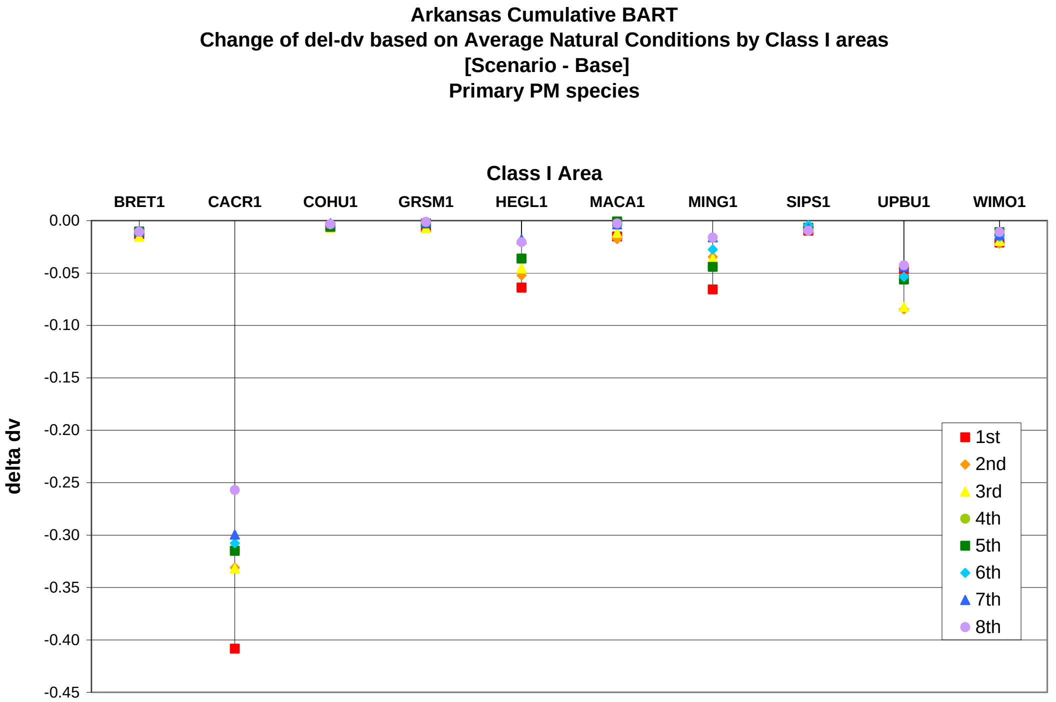

Figure 3-2c. Visibility improvement (del-dv) [Post-control – Base] based on primary PM emissions (OMC, EC, Soil and CM) from all Arkansas subject-to-BART sources.

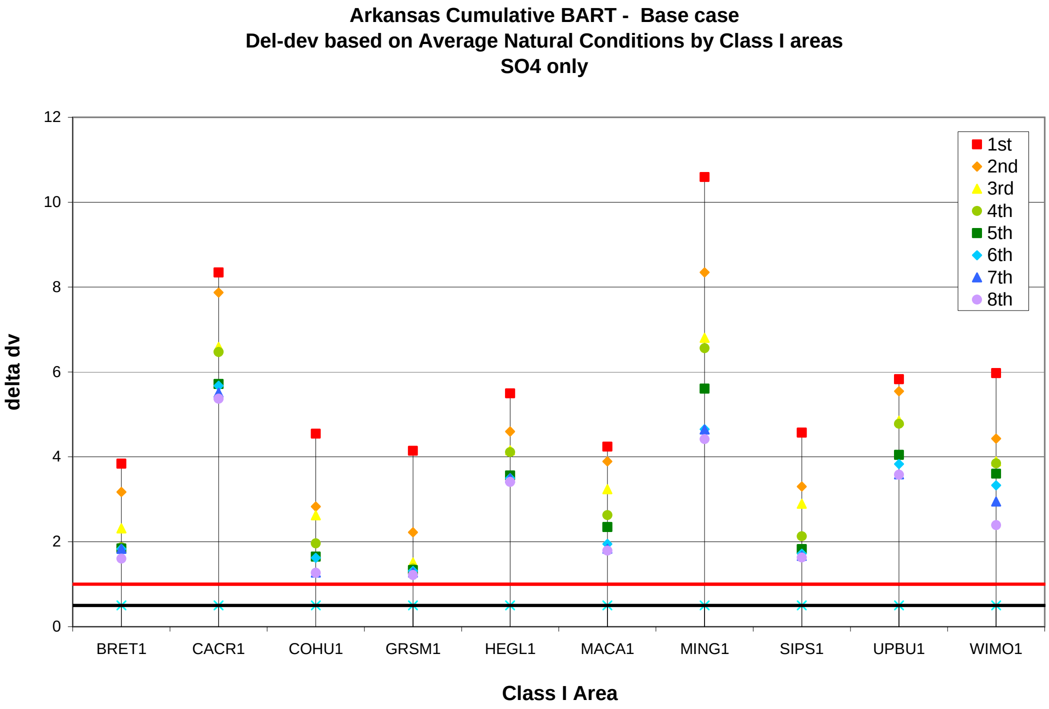

Figure 3-3a. Base case visibility impacts (del-dv) based on sulfate (SO4) due to SOx emissions (SO2 and SO4) from all Arkansas subject-to-BART sources.

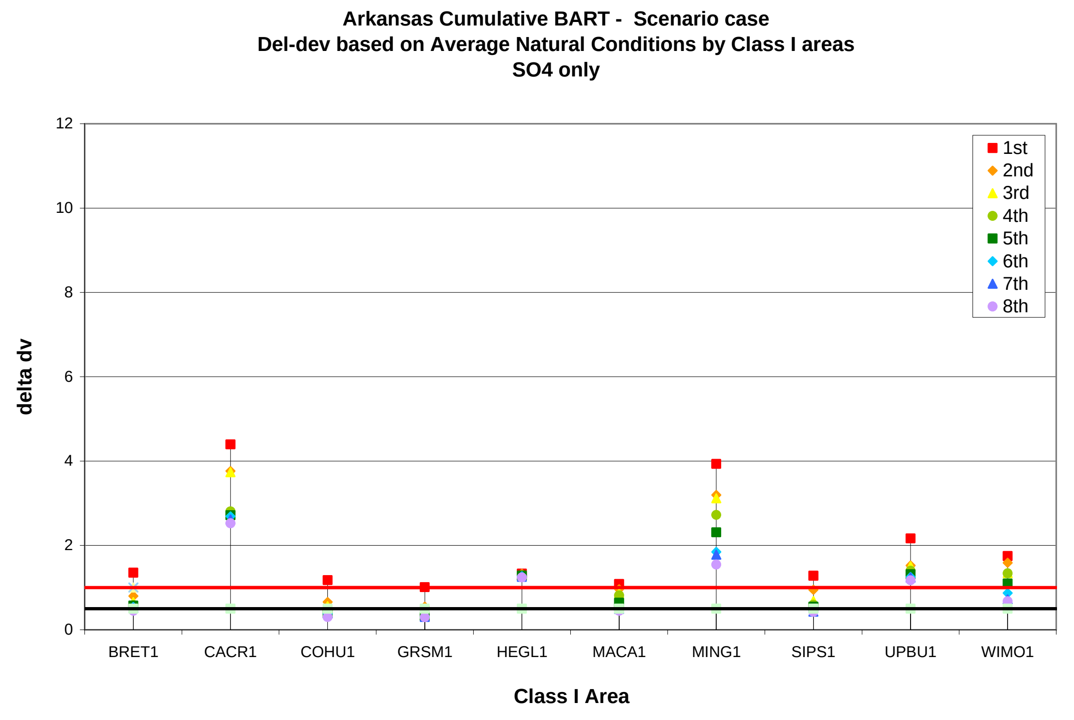

Figure 3-3b. Post-control case visibility impacts (del-dv) based on sulfate (SO4) due to SOx emissions (SO2 and SO4) from all Arkansas subject-to-BART sources.

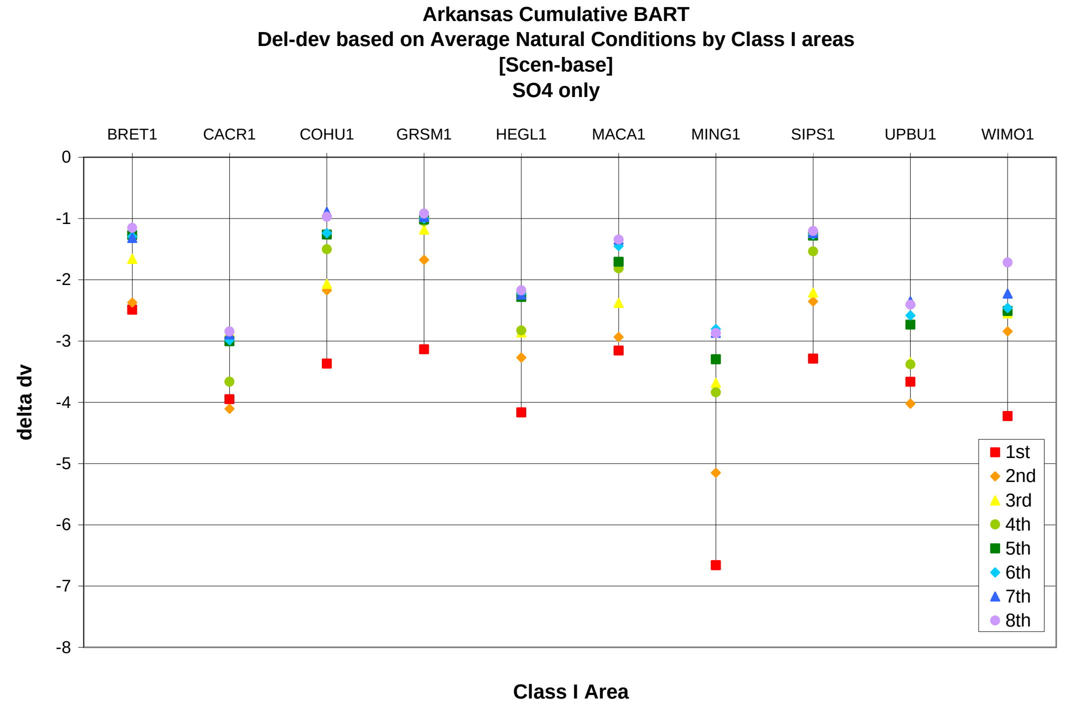

Figure 3-3c. Visibility improvement (del-dv) [Post-control – Base] based on sulfate (SO4) due to SOx emissions (SO2 and SO4) from all Arkansas subject-to-BART sources.

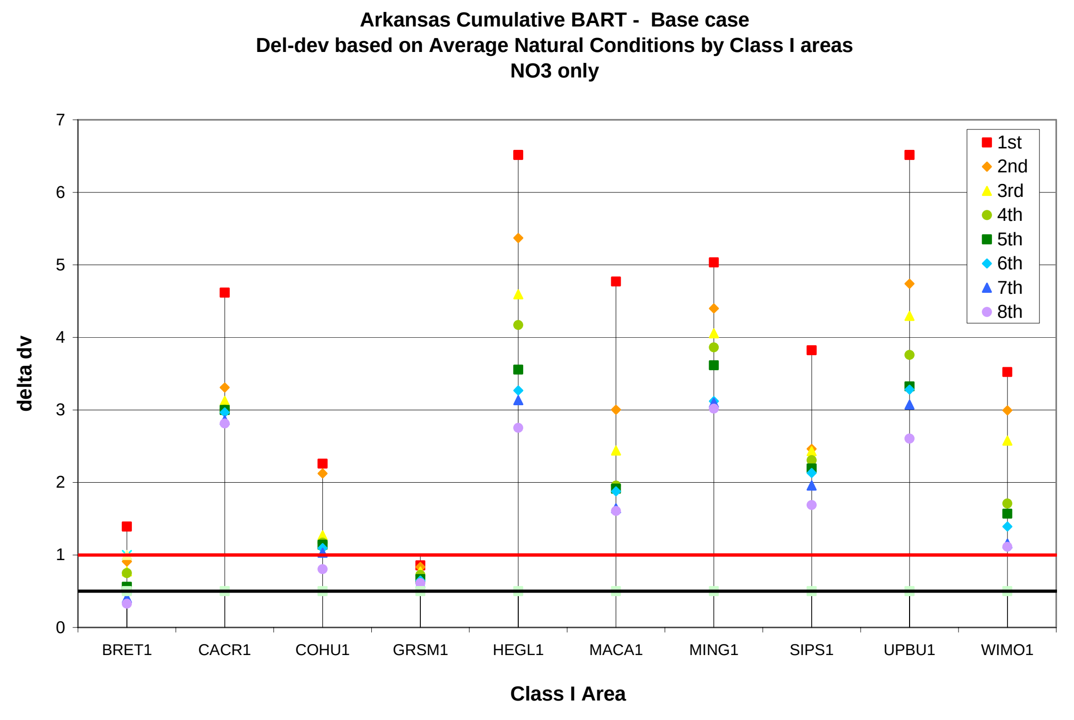

Figure 3-4a. Base case visibility impacts (del-dv) based on nitrate (NO3) due to NOx emissions (NO, NO2, HNO3 and NO3) from all Arkansas subject-to-BART sources.

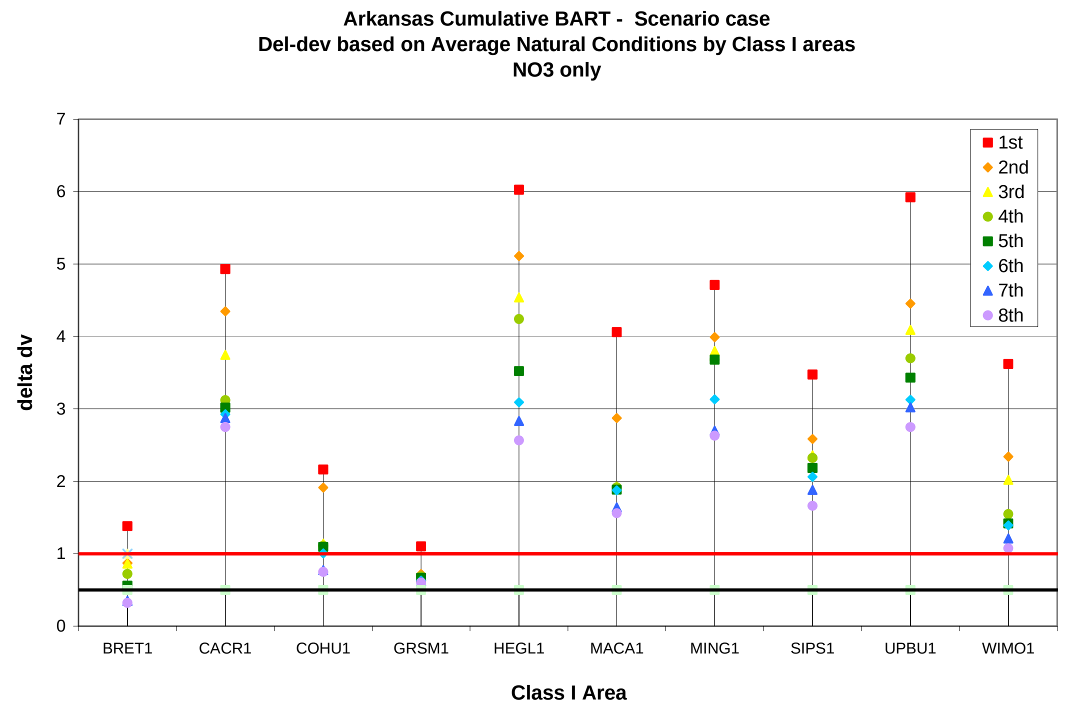

Figure 3-4b. Post-control case visibility impacts (del-dv) based on nitrate (NO3) due to NOx emissions (NO, NO2, HNO3 and NO3) from all Arkansas subject-to-BART sources.

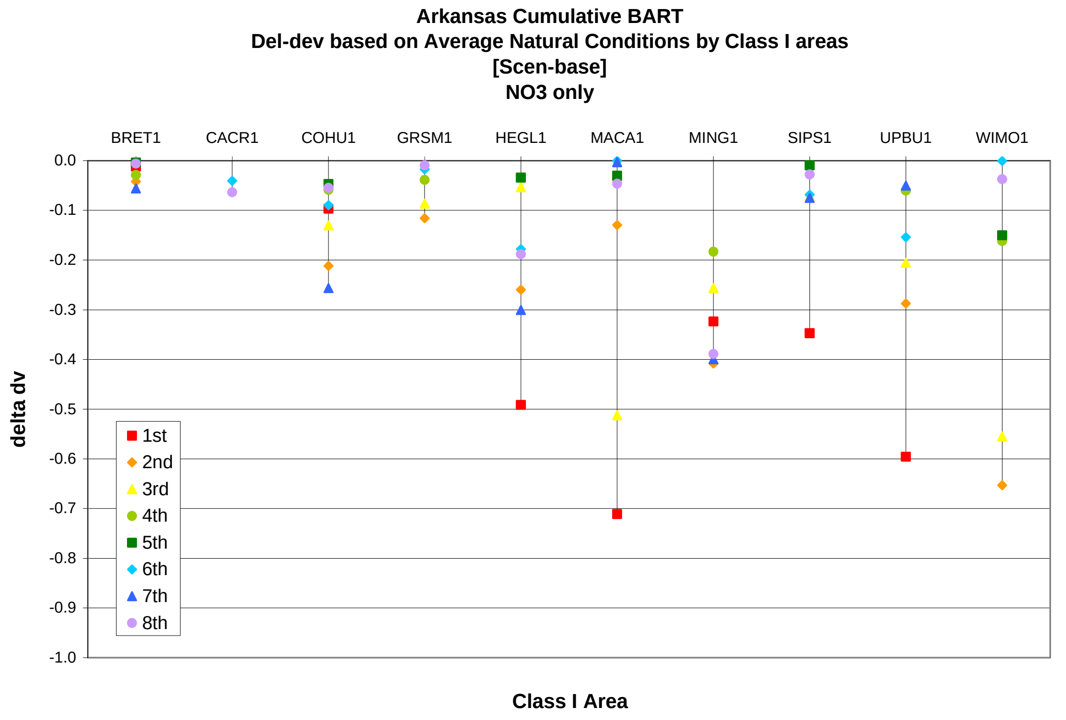

Figure 3-4c. Visibility improvement (del-dv) [Post-control – Base] based on nitrate (NO3) due to NOx emissions (NO, NO2, HNO3 and NO3) from all Arkansas subject-to-BART sources.

INDIVIDUAL ARKANSAS SUBJECT-TO-BART SOURCE VISIBILITY IMPACTS

This section presents the visibility impacts across the 5 primary Class I areas of interest (i.e., CACR, HEGL, MING, UPBU and SIPS) based on the total PM impacts from each individual Arkansas subject-to-BART source. Figure 3-5a displays the 8 highest daily visibility impacts across the 5 Class I areas for each individual Arkansas subject-to-BART source for the base case (pre-control). These results are qualitatively consistent with the ADEQ subject-to-BART CALPUFF modeling that estimated the visibility impacts from each of the 6 Arkansas subject-to-BART sources exceed the 0.5 del-dv significant threshold that led to the ADEQ determination that they are subject-to-BART. The source-specific visibility impacts improve considerably in the post-control case as shown in Figures 3-5b and 3-5c. However, the post-control visibility impacts from each Arkansas BART source are still estimated to exceed 0.5 del-dv (Figure 3-5b). Table 3-2 displays the visibility impacts (del-dv) from total PM at each of the 5 primary Class I areas by BART sources. A brief summary of individual source's visibility impacts follows:

American Electric Power (Gentry Plant): The base case visibility impact for this source is dominated by sulfate with the highest impacts occurring at CACR. After controls, the visibility improvement is as high as 3.3 del-dv. SO_2 and NOx emissions are reduced by 80% and 25%, respectively, due to the BART controls. With a much greater extent of SO_2 reduction, the replacement of sulfate by nitrate is possible. An apparent example is seen here as the 1st high visibility impact at MING is higher in the post-control case (2.2 del-dv) than in the pre-control base case (2.1 del-dv). However, in most cases and always in the very largest visibility impacts, the post-control extinction is less than the pre-control values.

Arkansas Electric Cooperative (Bailey Plant): The highest visibility impact due to this source is estimated at MING. This source reduced SO_2 emissions by 56% without any NOx emission reduction. However, the NOx emissions are relatively small compared to other sources. Thus, visibility impacts in both the base case and post-control case are sulfate dominated.

Arkansas Electric Cooperative (McClellan Plant): The highest visibility impact is estimated at CACR. After controls, the visibility improvement is as high as 4 del-dv. This source reduced SO_2 emissions by 64% without any NOx emission reduction. However, the NOx emissions are relatively small compared to other sources. Thus, both base case and post-control case are sulfate dominated.

Domtar: As noted previously, the emissions provided for the Domtar source were understated when compared to the actual maximum 24-hour emissions that are supposed to be used in a BART analysis. Corrected emissions were provided when the model simulations were almost completed and the rerunning of the Domtar analysis would have compromised the study's schedule and budget. Consequently, a sensitivity analysis of the corrected emissions to the visibility impacts is presented in the next section. Using the understated Domtar emissions we see that the BART controls on the Domtar source has the least benefits of any of the 6 Arkansas subject-to-BART facilities.

Lake Catherine: The highest impact due to the Lake Catherine source is estimated at the UPBU and MING Class I areas for the base case and post-control case, respectively. The base case is dominated by sulfate but the post-control case is dominated by both sulfate and nitrate. This source has a significant reduction of primary emissions which plays a major role in visibility improvement at CACR due to primary PM reduction as shown in Figure 3-2c.

Entergy/White Bluff: This source reduces SO_2 and NOx emissions by 81% and 69%, respectively due to the BART controls. These are major reductions in these two precursors among the 6 Arkansas subject-to-BART sources. The visibility improvements are evident in all five of the Class I areas of interest with the largest visibility improvement of 6.6 del-dv at MING. The base case is dominated by sulfate; however the post-control is dominated by both sulfate and nitrate.

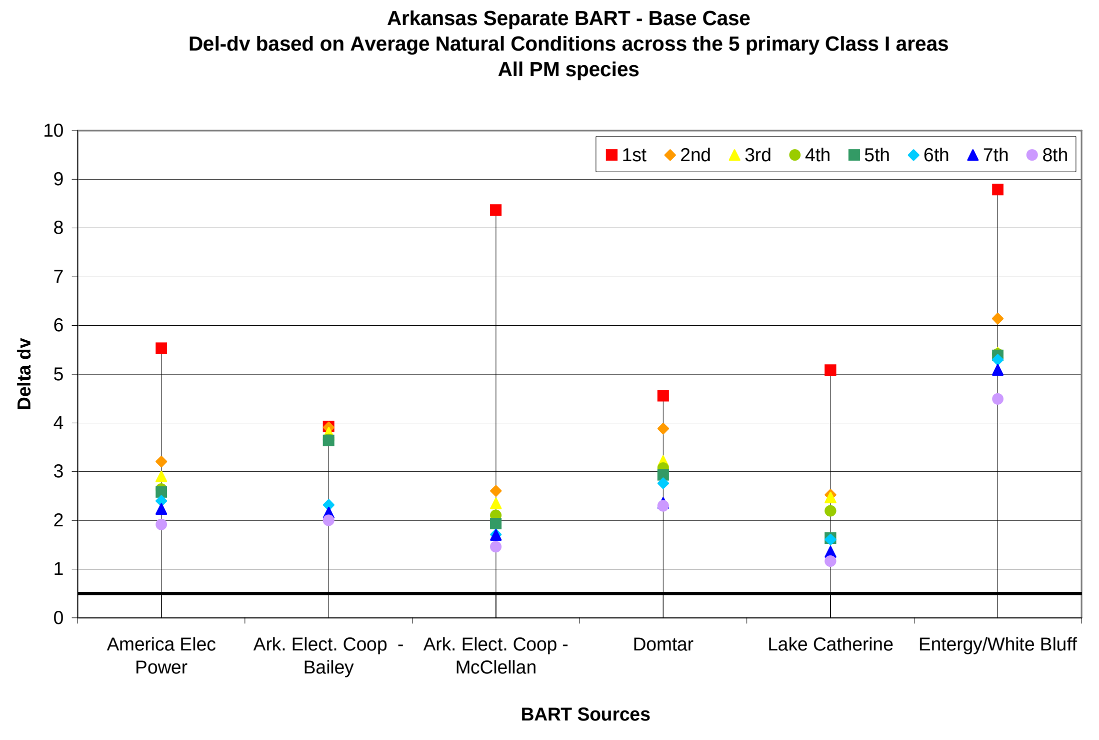

Figure 3-5a. Base case visibility impacts (del-dv) across the 5 primary Class I areas based on total PM from all emissions for each Arkansas subject-to-BART source.

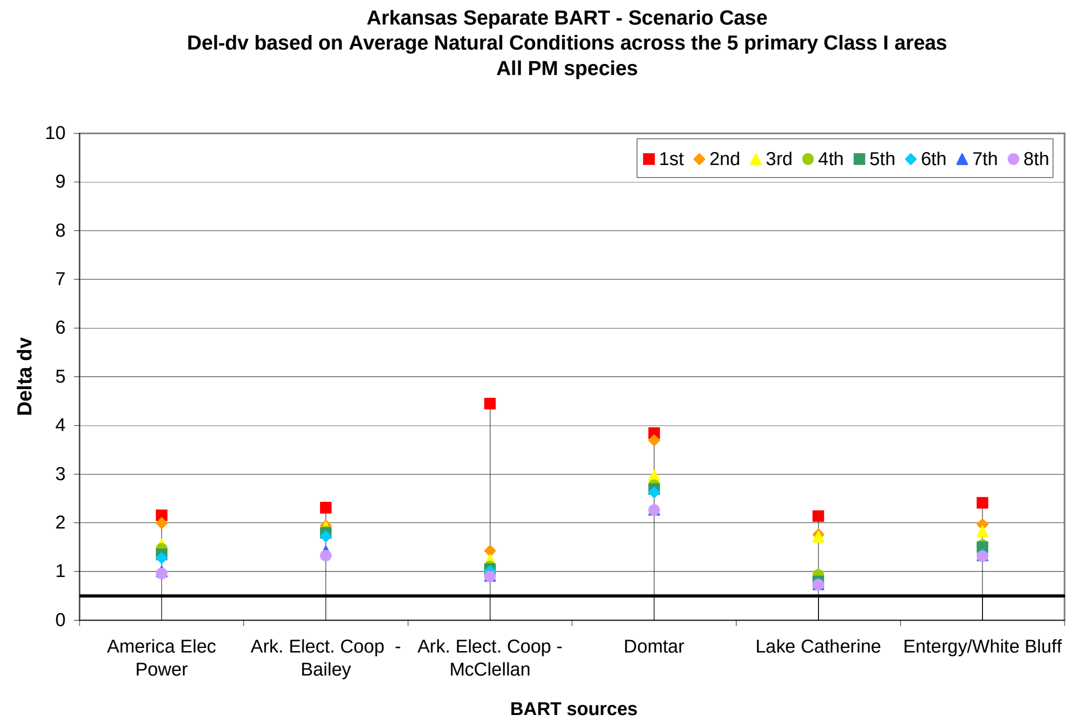

Figure 3-5b. Post-control case visibility impacts (del-dv) across the 5 primary Class I areas based on total PM from all emissions for each Arkansas subject-to-BART source.

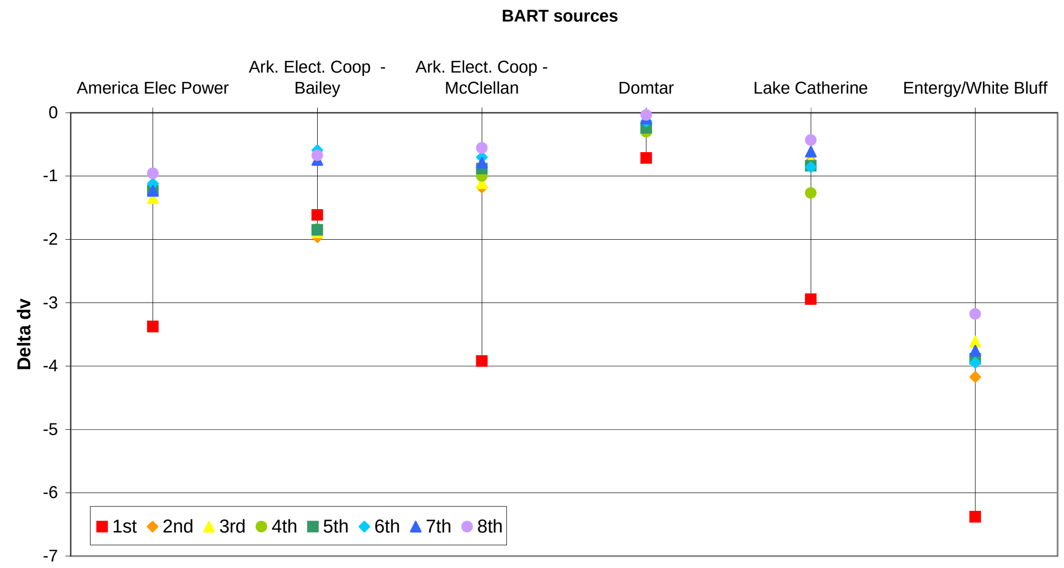

Figure 3-5c. Visibility improvement (del-dv) [Post-control – Base] across the 5 primary Class I areas based on total PM from all emissions for each Arkansas subject-to-BART source.

Table 3-2. Visibility impacts (del-dv) from total PM at 5 primary Class I areas from all emissions for each Arkansas subject-to-BART source.

BART source	Rank	CACR		HEGL		MING		SIPS		UPBU	
		base	control	base	control	base	control	base	control	base	control
America Elec Power	1st	5.5	1.6	3.8	1.9	2.1	2.2	1.0	0.8	3.3	1.9
	8th	1.9	1.0	1.5	0.7	1.0	0.8	0.5	0.4	1.3	0.9
Ark. Elect. Coop - Bailey	1st	2.0	1.3	1.9	1.5	3.9	2.3	1.0	0.6	1.5	1.7
	8th	0.9	0.8	0.8	0.7	2.0	1.3	0.4	0.4	0.9	0.6
Ark. Elect. Coop - McClellan	1st	8.4	4.4	1.9	1.7	1.9	1.1	1.2	1.2	1.9	1.4
	8th	1.5	0.9	1.1	0.6	1.0	0.6	0.4	0.2	1.0	0.7
Domtar	1st	4.6	3.8	1.9	1.1	1.5	1.1	0.7	0.6	1.7	1.5
	8th	2.3	2.3	0.5	0.6	0.6	0.5	0.4	0.3	0.6	0.6
Lake Catherine	1st	1.6	1.3	2.5	2.1	3.7	1.7	0.9	0.7	5.1	1.8
	8th	0.8	0.6	0.7	0.6	0.7	0.7	0.4	0.4	1.2	0.6
Entergy/White Bluff	1st	7.4	2.4	5.3	1.7	8.8	2.4	4.1	1.0	5.2	1.4
	8th	4.5	1.3	2.4	1.0	2.6	0.9	1.4	0.5	2.9	1.1

DOMTAR SENSITIVITY ANALYSIS

During the modeling process, ADEQ informed that the emissions provided for the Domtar Arkansas subject-to-BART source were incorrect. To address this issue, a sensitivity analysis was conducted using the revised Domtar emissions for both the pre-control and post-control emission scenarios. The approach in the sensitivity was to scale each of the PM components based on the emissions ratio of the primary PM precursor species for the corrected to modeled emission rates.. For instance, sulfate concentrations would be scaled by a ratio between the revised SO_2 emissions and the SO_2 emissions used in the modeling: $[SO_4]_{revised} = [SO_4]_{old} \times [SO_2]_{revised}/[SO_2]_{old}$. Similarly, nitrate and primary PM concentrations would be scaled based on NOx and primary PM emissions ratio, respectively. This approach implies that the relationship between the PM species and the primary PM precursor emissions is linear, which is valid for primary PM but likely would overstate the impacts for secondary sulfate and especially secondary nitrate. The atmosphere is not always ammonium limited and both sulfate and nitrate can increase, thus, it should be considered conservative. Table 3-3 lists the ratio of the revised to modeled emissions used to scale the Domtar modeled SO4, NO3 and primary PM concentration impacts in the Class I areas for the Domtar sensitivity analysis.

Table 3-3. Ratio of Domtar revised to modeled SO_2, NO_x and PM_{10} emissions used to scale the Domtar modeled SO4, NO3 and PM concentration impacts in the Domtar sensitivity analysis.

Scenario	SO_4^{2-}	NO_3^-	PM
Pre-Control Base Case	2.18	1.00	1,08
Post-Control Case	2.18	1.17	1.00

The highest impact from this source (as listed in Table 3-2) is estimated at CACR due to its close proximity of Domtar to this Class I area. The results of the Domtar sensitivity analysis for the cumulative visibility impacts due to all Arkansas subject-to-BART sources by Class I area is shown in Figure 3-6a. These results are very similar to the cumulative results shown previously with the understated Domtar emissions (Figure 3-1a), which implies that the Domtar visibility contributions are a small component of the maximum cumulative Arkansas BART sources' impacts. This is because of the fact that the base case Domtar emissions are relatively small compared to other Arkansas subject-to-BART sources. However, emissions from Domtar are only slightly reduced due to the BART controls relative to the other Arkansas BART sources so that its emissions are a more substantial component of the cumulative emissions in the post-control case. As a result, the revised emissions worsen the cumulative visibility impacts to some extent, specifically by about 2 del-dv at CACR. The separate visibility impacts across the 5 primary Class I areas shown in Figure 3-7a suggests that the revised emissions increase the impacts as high as 3.5 del-dv for both scenarios. In addition, Figure 3-7b suggests that the emission reduction of this source only improves the visibility by less than 1 del-dv in both the modeled and revised emissions cases.

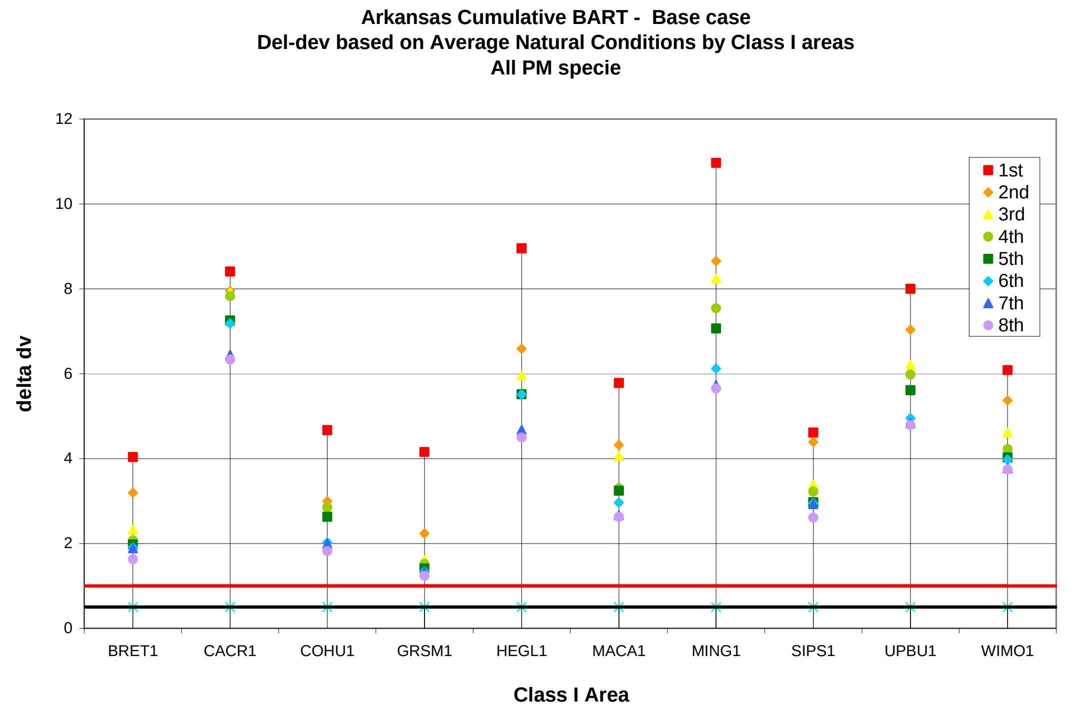

Figure 3-6a. Estimated base case visibility impacts (del-dv) based on total PM from all Arkansas BART sources with revised Domtar emissions.

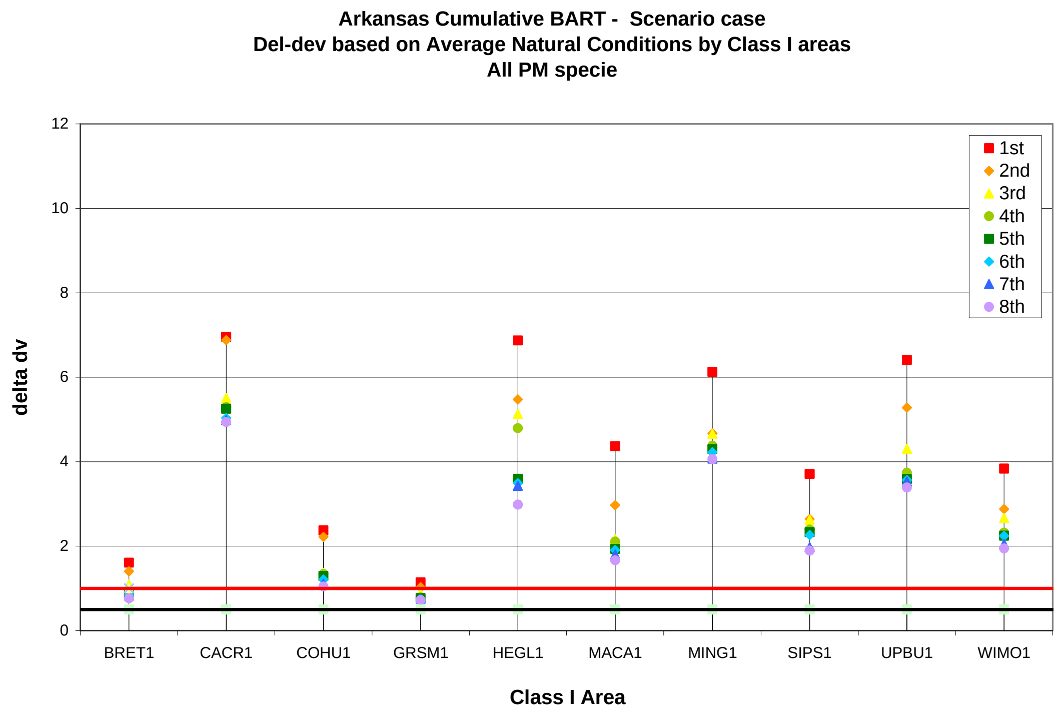

Figure 3-6b. Estimated post-control case visibility impacts (del-dv) based on total PM from all Arkansas BART sources with revised Domtar emissions.

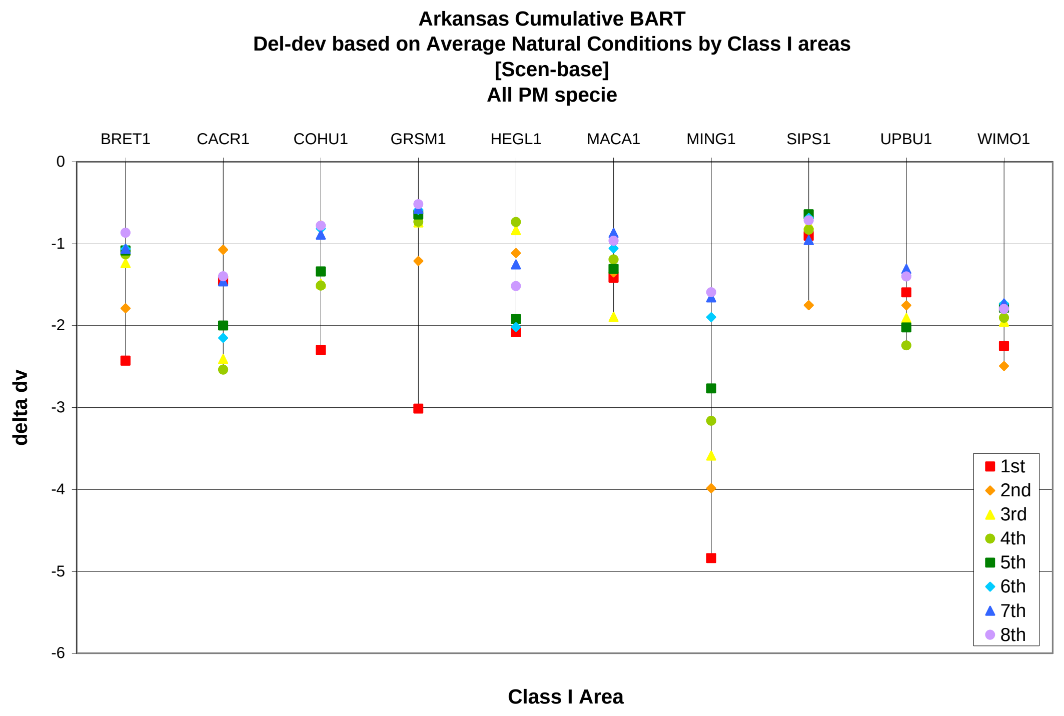

Figure 3-6c. Estimated visibility improvement (del-dv) [Post-control – Base] of total PM from all Arkansas BART sources with revised Domtar emissions.

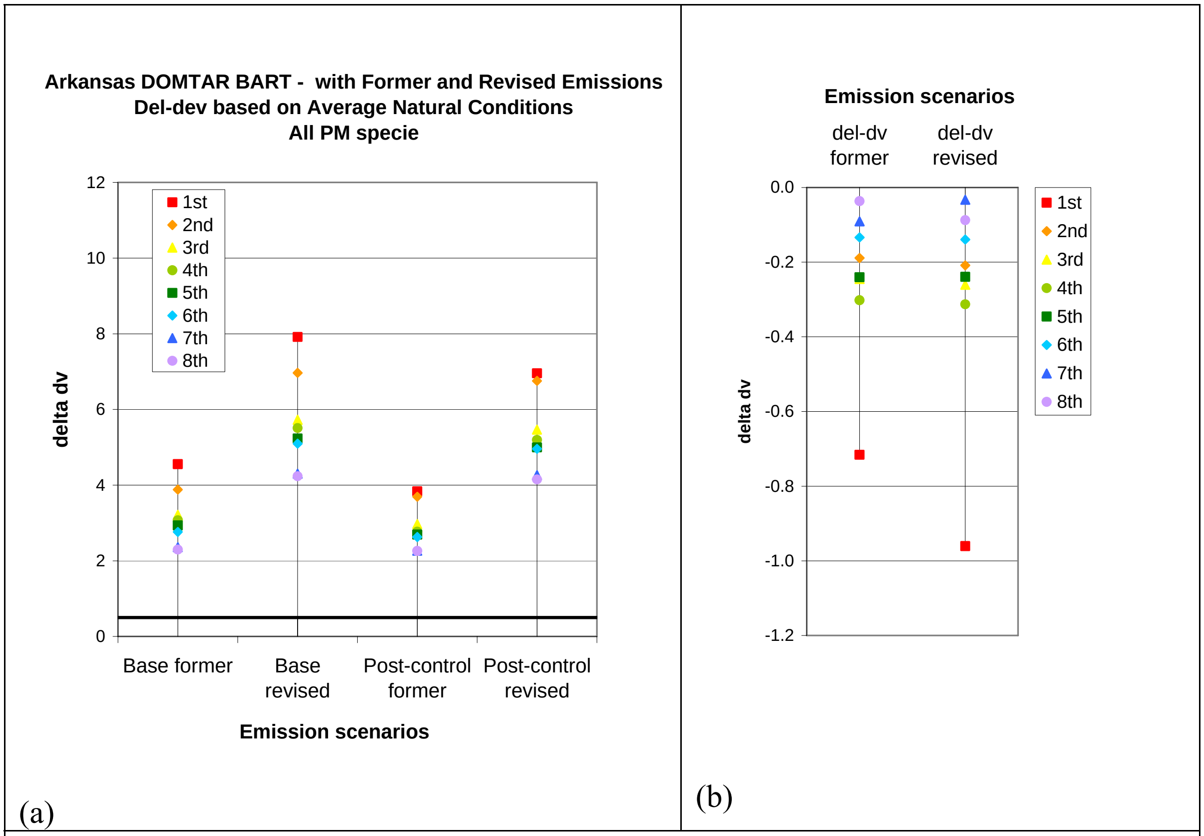

Figure 3-7. Comparison of the visibility impacts with the understated (former) and with the revised emissions: (a) base case and post-control visibility impacts; and (b) visibility improvement (del-dv) [Post-control – Base] across the 5 primary Class I areas based on total PM.

4.0 SUMMARY AND CONCLUSIONS

The Arkansas Department of Environmental Quality (ADEQ) performed single-source BART exemption modeling using the CALPUFF model and determined that approximately 9 units at 6 facilities in Arkansas are subject-to-BART. Therefore, these facilities are required to evaluate BART controls, install BART controls if necessary and perform post control modeling to determine the degree of visibility improvement that the BART controls provide. In accordance with the EPA's guidance for BART determinations, cumulative modeling needs to be performed to determine the collective impact of the Arkansas subject-to-BART sources on visibility at Class I areas.

Visibility impacts were calculated at each Class I area using the 24-hour PM concentration estimates produced by Comprehensive Air-quality Model with extensions (CAMx) PM Source Apportionment Technology (PSAT) for each Arkansas BART facility at each Class I area. A new 2002 CAMx 12/4 km modeling database was developed from the 2002 modeling performed by the Central Regional Air Partnership (CENRAP). The 4 km domain covered Arkansas and adjacent areas including the Arkansas subject-to-BART sources and most of the key Class I areas of interest. In order to properly represent the near-source plume dynamics and chemistry, the CAMx Plume-in-Grid (PiG) subgrid-scale plume model was invoked for the Arkansas subject-to-BART sources. The maximum 24-hour visibility estimates at any receptor representing the Class I area was used to represent the visibility impact for that day. The following section summarizes the visibility improvement at the Class I area of interest after applying BART controls at 6 Arkansas subject-to-BART facilities.

CUMULATIVE BART ANALYSIS

The application of BART controls on the 6 Arkansas subject-to-BART facilities is estimated to result in substantial improvements in visibility all 10 Class I areas studies, with the largest visibility improvement of 5 del-dv at Mingo. The highest cumulative visibility impacts due to all PM species in the pre-control base case ranged from 4 to 11 del-dv across the Class I areas, whereas the highest visibility impacts in the post-control case ranged from 1 to 7 del-dv. Despite these apparent visibility improvements, the cumulative visibility impacts due to all Arkansas BART sources in the post-control case still exceed 1 del-dv at most Class I areas of interest.

The Arkansas BART cumulative visibility impacts were also separately analyzed by each visibility precursor (SOx, NOx, and primary PM). The analysis suggested that the visibility impacts from the primary PM emissions (i.e., due to OMC, EC, Soil and CM emissions) do not significantly contribute to visibility impairment at Class I areas compared to sulfate (SO4) and nitrate (NO3). Visibility improvement due to reduction in SOx emissions, thus, reduction in sulfate, is most effective. Although NOx emissions are also reduced in the post-control case, there is not as much improvement gain from corresponding particle nitrate (NO3) reductions as seen for SO4. This is due to the fact that the decrease in SO4 concentrations due to the SO2 controls releases ammonium that becomes available to convert gaseous nitric acid to particle NO3 (i.e., "nitrate replacement").

During the modeling process, ADEQ was informed that the emissions provided for the Domtar Arkansas subject-to-BART source were understated. To address this issue, a sensitivity analysis was performed using the corrected Domtar emissions for both the pre- and post-control scenarios was conducted. The analysis suggested that the revised (higher) Domtar emissions worsen the visibility improvement in the post-control case, specifically at by 2 del-dv at Caney Creek.

INDIVIDUAL BART SOURCE ANALYSIS

The CAMx/PSAT results were analyzed separately for each of the 6 Arkansas subject-to-BART facilities. The visibility impacts for the pre-control base case exceeded the 0.5 del-dv significant threshold for each Arkansas subject-to-BART source. Which is consistent with the ADEQ CALPUFF BART modeling that determined that these 6 sources are reasonably anticipated to contribute significantly to visibility impairment at a Class I area and therefore were determined to be subject-to-BART. The effects of the BART controls are to show some visibility improvements across the 5 primary Class I areas of interest. However, the post-control visibility impacts from each individual Arkansas BART source still exceed 0.5 del-dv threshold.

SENSITIVITY ANALYSIS TO THE DOMTAR EMISSIONS

Emissions used in the modeling for the Domtar Arkansas subject-to-BART sources were understated and revised emissions were provide too late in the process too include in the modeling. Revision of Domtar emissions negligibly change the cumulative pre-control base case visibility impacts because the Domtar base case emissions are relatively small compared to the other Arkansas BART sources. However, the revised emissions worsen the cumulative visibility impacts to some extent, specifically by about 2 del-dv at CACR. This is because the level of emissions control at Domtar is less than for the other Arkansas BART sources so the Domtar emissions are relatively more important in the post-control case than pre-control base case.

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Appendix 9.3A
BART Analyses for the Subject-to-BART Sources

Arkansas Electric Cooperative Corporation
Best Available Retrofit Technology
Engineering Analysis

October 20, 2006

Prepared by:
Stephen Cain
Senior Environmental Engineer
AECC

AECC BART Engineering Analysis

Arkansas Electric Cooperative Corporation (AECC) has two electric generating units (EGUs) subject to best available retrofit technology (BART) regulations. They are two main boilers – one at Carl E. Bailey Generating Station (Bailey) near Augusta, Arkansas and the other at John L. McClellan Generating Station (McClellan) near Camden, Arkansas.

Both boilers are currently permitted to burn both natural gas and fuel oil. The fuel oil burned at the plants is subject to sulfur content limits: 2.3% by weight at Bailey and 2.8% by weight at McClellan.

During the BART determination process, the Arkansas Department of Environmental Quality (ADEQ) performed CALPUFF modeling that showed SO2 to be the contributing pollutant to visibility impacts at nearby Class I areas. Both NOx and particulate matter (PM) were shown not to cause or contribute to visibility impacts.

CALPUFF was used to determine the pre-control visibility impacts and the post-control visibility impacts. Constant source specific input data for the two units are as follows:

Unit	Bailey Unit 1	McClellan Unit 1
Stack Height	50.9 m	48.8 m
Base Elevation	61.3 m	33.5 m
Stack Diameter	3.0 m	3.3 m
Exit Velocity	28.04 m/s	28.04 m/s
Exit Temperature	444.0 K	444.0 K

Pre-Control Modeling

Emission rates for the pre-control visibility impacts are as follows:

Unit	Bailey Unit 1	McClellan Unit 1
SO2 Emission Rate	299.34 g/s	346.19 g/s
NOx Emission Rate	36.93 g/s	47.12 g/s
PM Emission Rate	21.73 g/s	28.76 g/s

These worst-case rates were determined by taking the highest 24-hour emission rate during one day during operating years 2001 through 2003. The SO2 and NOx emissions are measured, and the PM emissions are calculated. The modeling assumed that the units emitted these emission rates constantly at a 100% capacity factor for those three years. (In reality, the units operate at only a 20% capacity factor at emission rates usually much less than those listed above – especially when burning natural gas where the SO2 and PM emissions are much lower.)

The initial modeling was cumulative emissions modeling. Cumulative emission modeling is when individual emission rates are added into one aggregate total emission rate.

The cumulative emission modeling results are shown on the next page. The numbers in the table show the number of days that the Class I areas were impacted in the given year. Impacts of equal to or greater than 1 deciview are said to ‘cause’ visibility impacts, and impacts of equal to or greater than 0.5 deciviews are said to ‘contribute’ to visibility impacts.

The results of the cumulative modeling indicate that both units cause and contribute to visibility impacts at one or more Class I areas. Since that is the case, both units are subject to BART.

Pre-Control CALPUFF Modeling Results for Cumulative Emissions

Facility Name/Location (BART File Name)	Class I Area*	No of days with Δ-dv =>0.50 for 2001	No of days with Δ-dv =>1.00 for 2001	Maximum Δdv	No of days with Δ-dv =>0.50 for 2002	No of days with Δ-dv =>1.00 for 2002	Maximum Δdv	No of days with Δ-dv =>0.50 for 2003	No of days with Δ-dv =>1.00 for 2003	Maximum Δdv
Ark. Elect. Coop - Bailey Plant / Augusta (ARAU)	CACR	6	1	1.059	14	2	1.726	10	4	1.841
	HEGL	8	0	0.961	11	1	1.594	13	2	1.311
	MING	8	1	1.464	19	7	1.558	21	2	1.660
	SIPS	4	0	0.916	6	1	1.054	3	0	0.944
	UPBU	5	0	0.981	8	0	0.688	14	2	1.601
Ark. Elect. Coop - McClellan Plant / Camden (ARCA)	CACR	23	7	2.081	20	3	2.197	24	6	1.460
	HEGL	12	1	1.411	2	1	2.247	4	1	1.209
	MING	9	2	1.179	4	0	0.687	5	0	0.700
	SIPS	5	0	0.817	7	2	1.312	7	0	0.729
	UPBU	13	3	1.196	5	0	0.773	7	0	0.898

Note: Δdv = change in deciview

* CACR = Caney Creek Wilderness Area, AR; HEGL = Hercules-Glade Wilderness Area, MO; MING = Mingo Wilderness, MO; SIPS = Sipsey Wilderness Area, AL; UPBU = Upper Buffalo Wilderness Area, AR

ADEQ then performed pollutant specific modeling. This modeling determined which of the three pollutants – SO2, NOx, and/or PM – was impacting visibility.

The table on the next page shows the results of the NOx modeling. Notice that NOx does not cause or contribute to visibility impacts. Since the PM emissions were less than NOx, it was assumed that PM also does not cause or contribute to visibility impacts. Therefore, the impacts are caused by SO2 emissions.

As a result, AECC must perform and submit to ADEQ a five-factor engineering analysis to determine the appropriate level of BART for SO2 control for both plants. Those five factors are:

1. Identify all available retrofit control technologies;
2. Eliminate technically infeasible options;
3. Evaluate control effectiveness of remaining control technologies;
4. Evaluate impacts and document the results; and
5. Evaluate visibility impacts.

CALPUFF Modeling Results for NOx Emissions

Facility Name/Location (BART File Name)	Class I Area*	No of days with ➂-dv =>0.50 for 2001	No of days with ➂-dv =>1.00 for 2001	Maximum ➂dv	No of days with ➂-dv =>0.50 for 2002	No of days with ➂-dv =>1.00 for 2002	Maximum ➂dv	No of days with ➂-dv =>0.50 for 2003	No of days with ➂-dv =>1.00 for 2003	Maximum ➂dv
Ark. Elect. Coop - Bailey Plant / Augusta (ARAU)	CACR	0	0	0.112	0	0	0.150	0	0	0.153
	HEGL	0	0	0.146	0	0	0.161	0	0	0.107
	MING	0	0	0.133	0	0	0.347	0	0	0.233
	SIPS	0	0	0.062	0	0	0.036	0	0	0.069
	UPBU	0	0	0.149	0	0	0.075	0	0	0.122
Ark. Elect. Coop - McClellan Plant / Camden (ARCA)	CACR	0	0	0.421	0	0	0.278	0	0	0.310
	HEGL	0	0	0.087	0	0	0.300	0	0	0.128
	MING	0	0	0.094	0	0	0.134	0	0	0.097
	SIPS	0	0	0.088	0	0	0.087	0	0	0.066
	UPBU	0	0	0.011	0	0	0.095	0	0	0.174

1. Identify All Available Retrofit Control Technologies

There are two types of control technologies: add-on control technologies and pollution prevention technologies. Add-on technologies are post-combustion processes such as scrubbers. Pollution prevention technologies are pre-combustion practices such as fuel changing.

The only existing control technologies at these EGUs are the sulfur limits of the fuel oil listed in their air permits. These limits are 2.3% sulfur by weight at Bailey and 2.8% sulfur by weight at McClellan.

Due to the dates of installation of these two EGUs, they are grandfathered from being subject to New Source Performance Standards (NSPS) for utility boilers codified in 40 CFR Part 60.

For SO2 reductions at the two plants, AECC identified the following two retrofit controls:

SO2 Control Option	Technology Type
Scrubber	Add-On
Lower Sulfur Content of Fuel	Pollution Prevention

2. Eliminate Technically Infeasible Options

Neither of the two control options listed is considered technically infeasible for these two units.

3. Evaluate Control Effectiveness of Remaining Control Technologies

In the tables below, the control effectiveness is given for each control technology. The technologies are listed as most effective to least effective for each pollutant.

SO2 Control Option	Technology Type	Control Effectiveness
Scrubber	Add-On	95%
Lower Sulfur Content of Fuel	Pollution Prevention	55% (Bailey); 65% (McClellan)

4. Evaluate Impacts and Document the Results

EPA requires a four-part impact evaluation of the control options. The four parts are:

1. Costs of compliance;
2. energy impacts;
3. non-air quality environmental impacts; and
4. remaining useful life.

4.1 Cost of Compliance

The costs for the SO2 scrubbers were estimated using the Integrated Environmental Control (IEC) cost model provided by the Electric Power Research Institute (EPRI).

The financial requirement for an SO2 scrubber at each of the two units is noted in the table below. The output of the IEC calculations and design assumptions can be seen in Appendix A. Note that all of the estimates are based on a capacity factor of 20%.

Scrubber Costs

Unit	Capital Requirement	Annualized Costs	$/ton Removed
Bailey Unit 1	$54,405,825	$8,106,900	$2,108.25
McClellan Unit 1	$57,050,462	$8,563,940	$1,658.32

The financial requirement for changing to lower-sulfur fuel oil is noted in the table below. The calculations are shown in Appendix B.

Lower-Sulfur Fuel Oil Costs

Unit	Capital Requirement	Annualized Costs	$/ton Removed
Bailey Unit 1	$0	$59,524	$54.90
McClellan Unit 1	$0	$238,095	$158.60

Combusting a lower-sulfur fuel oil is much more cost effective than installing and operating scrubbers.

4.2 Energy Impacts

The use of an SO2 scrubber at either of the two units will have energy impacts. The estimated impacts are listed in the table below. The results of the IEC calculations for energy impacts are shown in Appendix A.

Unit	Energy Impact	Cost of Energy	Annual Cost*
Bailey Unit 1	1.688 MWH	$55/MWH	$162,656
McClellan Unit 1	1.894 MWH	$55/MWH	$182,506

*At 20% capacity factor.

There are no energy impacts from using a lower-sulfur fuel oil.

4.3 Non-Air Quality Environmental Impacts

SO2 scrubbers consume water and require sludge disposal. The estimates listed in the table below are taken from the IEC results in Appendix A.

Unit	Water Consumed	Sludge Disposed
Bailey Unit 1	119 gpm	12,427 lbs/hr
McClellan Unit 1	133 gpm	16,750 lbs/hr

Changing to a lower-sulfur fuel oil has no non-air quality environmental impacts.

4.4 Remaining Useful Life

The Bailey plant began operation in 1968, and the McClellan plant began operation in 1971. These plants are 38 and 35 years old, respectively. AECC does not intend to shut down either of these plants in the near future. However, any requirement to install and operate a high capital cost control – such as an SO2 scrubber – may cause the retirement of these units.

5. Evaluate Visibility Impacts

The next step was to perform post-control modeling. Since both AECC and ADEQ agreed that the most cost effective control would be to reduce the sulfur in the fuel oil, ADEQ performed the modeling with updated emission rates. Those rates are as follows:

Unit	Bailey Unit 1	McClellan Unit 1
SO2 Emission Rate	130.42 g/s	123.90 g/s
NOx Emission Rate	36.93 g/s	47.12 g/s
PM Emission Rate	21.73 g/s	28.76 g/s

The NOx and PM emission rates are unchanged, but the SO2 emission rates are much lower due to the proposed fuel oil limit of 1% sulfur by weight.

The modeling results for cumulative modeling with the lower SO2 emission rates are shown on Page 11.

As shown, the impacts are drastically reduced. In fact, the modeling shows that the Bailey plant has no days of impact equal to or greater than 1 deciview. The McClellan plant has only two days of impact – one at Caney Creek and one at Hercules-Glades and the maximum impact is only 1.011 dv and 1.042 dv respectively.

The differences between pre- and post-control impacts for the years 2001-2003 are shown in the following tables:

Bailey

	# of ≥0.5 dv	# of ≥1.0 dv
Pre-Control	150	23
Post-Control	22	0
Difference	128	23
% of Impacts Eliminated	85.3%	100.0%

McClellan

	# of ≥0.5 dv	# of ≥1.0 dv
Pre-Control	143	26
Post-Control	13	2
Difference	130	24
% of Impacts Eliminated	90.9%	92.3%

Post-Control CALPUFF Modeling Results

Facility Name/Location (BART File Name)	Class I Area*	No of days with ✆-dv =>0.50 for 2001	No of days with ✆-dv =>1.00 for 2001	Maximum ✆dv	No of days with ✆-dv =>0.50 for 2002	No of days with ✆-dv =>1.00 for 2002	Maximum ✆dv	No of days with ✆-dv =>0.50 for 2003	No of days with ✆-dv =>1.00 for 2003	Maximum ✆dv
Ark. Elect. Coop - Bailey Plant / Augusta (ARAU)	CACR	1	0	0.515	2	0	0.864	4	0	0.920
	HEGL	0	0	0.475	1	0	0.809	1	0	0.624
	MING	1	0	0.694	8	0	0.871	3	0	0.766
	SIPS	0	0	0.421	0	0	0.482	0	0	0.435
	UPBU	0	0	0.473	0	0	0.309	2	0	0.758
Ark. Elect. Coop - McClellan Plant / Camden (ARCA)	CACR	4	0	0.838	3	1	1.011	4	0	0.625
	HEGL	1	0	0.561	1	1	1.042	0	0	0.455
	MING	0	0	0.448	0	0	0.299	0	0	0.318
	SIPS	0	0	0.318	0	0	0.493	0	0	0.285
	UPBU	0	0	0.487	0	0	0.325	0	0	0.392

Control was switching to 1% sulfur fuel

Summary

AECC believes that burning a lower-sulfur fuel oil at these units should be considered as BART. ADEQ agreed with AECC during a meeting at ADEQ on August 15, 2006. This belief is supported by the fact that burning a lower-sulfur fuel is cost-effective, has no energy impact, has no non-air quality impacts, and greatly improves the visibility impacts on nearby Class I areas.

Appendix A
EPRI IEC Results for SO2 Scrubber Installations

			Bailey	McClellan
Inputs:				
Absorber Technology			Absorber	Absorber
Plant's Net Rating	MW		121.7	134.2
Plant Capacity Factor	%		20%	20%
Plant Location	State		AR	AR
Retrofit Factor			1.30	1.30
Fuel	Type		FUEL OIL	FUEL OIL
Percent Sulfur	%		2.30%	2.80%
SO2 Removal	%		95%	95%
Ca/S Removed Molar Ratio	Integer		1.03	1.03
Reagent Type			Limestone	Limestone
Reagent Cost	$/ton		$12.30	$12.30
Outputs:				
Reagent Required	tons/hr		3.75	5.05
Dibasic Acid Required	tons/hr		0.03	0.04
FGD Sludge, dry	tons/hr		6.21	8.37
FGD Byproduct	tons/hr		0.00	0.00
Boiler Efficiency	%		91.59%	91.59%
FGD Power Consumption	kW		1,688	1,894
Capital Costs:				
Cost Basis Year			2006	2006
Total Process Capital				
Area 10: Reagent Feed System	$		$11,378,335	$11,789,456
Area 20: SO2 Removal System	$		$14,067,992	$14,903,851
Area 30: Flue Gas System	$		$6,676,847	$7,064,533
Area 40: Regeneration	$		$0	$0
Area 50: Byproduct Handling	$		$0	$0
Area 60: Solids Handling	$		$2,300,186	$2,361,058
Area 70: General Support Equipment	$		$955,957	$971,809
Area 80: Miscellaneous Equipment	$		$1,519,499	$1,564,580
TOTAL	$		$36,898,815	$38,655,288
	$/kW		$303.13	$288.07
General Facilities	$		$3,689,882	$3,865,529
Engineering and Home Office Fees	$		$3,689,882	$3,865,529
Process Contingency	$		$885,572	$927,727
Project Contingency	$		$6,774,622	$7,097,111
Total Plant Cost (TPC)	$		$51,938,772	$54,411,183
	$/kW		$426.69	$405.49
Total Cash Expended (TCE)	$		$51,182,382	$53,618,787
	$/kW		$420.47	$399.59
Allowance for Funds (AFDC)	$		$1,512,780	$1,584,792
Total Plant Investment (TPI)	$		$52,695,162	$55,203,579
	$/kW		$432.90	$411.40
Preproduction Costs	$		$1,459,763	$1,564,100
Inventory Capital	$		$66,406	$89,506
Initial Catalyst and Chemicals	$		$0	$0
Prepaid Royalties	$		$184,494	$193,276
Total Capital Requirement (TCR)	$		$54,405,825	$57,050,462
	$/kW		$446.96	$425.16
Market Demand Escalation	$		$0	$0
Power Outage Penalty	$		$0	$0
Land Cost	$		$0	$0
TCR w/ Market Dem., Power Outage, & Land $	$		$54,405,825	$57,050,462
	$/kW		$446.96	$425.16

First-Year and Levelized Costs:			Bailey	McClellan
First-Year Costs:				
Fixed O&M:	$		$2,970,148	$3,092,642
	$/kW-Yr		$24.40	$23.05
	Mills/KWh		13.93	13.15
	$/ton SO2 removed		$774.10	$598.00
Variable O&M:	$		$380,035	$485,541
	$/kW-Yr		$3.12	$3.62
	Mills/KWh		1.78	2.07
	$/ton SO2 removed		$99.05	$93.89
Fixed Charges:	$		$3,264,350	$3,423,028
	$/kW-Yr		$26.82	$25.51
	Mills/KWh		15.31	14.56
	$/ton SO2 removed		$850.77	$661.88
Total:	$		$6,614,532	$7,001,210
	$/kW-Yr		$54.34	$52.18
	Mills/KWh		31.02	29.78
	$/ton SO2 removed		$1,723.92	$1,353.77
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr		$35.14	$33.19
	Mills/KWh		20.06	18.95
	$/ton SO2 removed		$1,114.83	$861.22
Variable O&M:	$/kW-Yr		$4.50	$5.21
	Mills/KWh		2.57	2.97
	$/ton SO2 removed		$142.64	$135.21
Fixed Charges:	$/kW-Yr		$26.82	$25.51
	Mills/KWh		15.31	14.56
	$/ton SO2 removed		$850.77	$661.88
Total:	$/kW-Yr		$66.45	$63.91
	Mills/KWh		37.93	36.48
	$/ton SO2 removed		$2,108.25	$1,658.32

LSFO Operating Cost Summary			Bailey	McClellan
Cost Basis Year			2006	2006
Important Operating Parameters				
Reagent Required:	lbs/hr		7,498.43	10,106.85
	tons/hr		3.75	5.05
	lbs/MMBtu		6.22	7.60
% SO2 Removal	%		95%	95%
SO2 Removed:	lbs/MMBtu		3.63	4.44
	lbs/hr		4,380.05	5,903.70
	tons/hr		2.19	2.95
	tons/year		3,836.92	5,171.64
SO2 Emitted:	lbs/MMBtu		0.19	0.23
	tons/year		201.94	272.19
Dibasic Acid Required:	lbs/hr		65.70	88.56
	tons/hr		0.033	0.044
	tons/year		57.55	77.57
SO2 Credits	tons/year		n/a	n/a
FGD Sludge to Disposal (dry, w/o flyash)	lbs/hr		12,426.83	16,749.65
	tons/hr		6.21	8.37
Water Makeup to FGD System	K gpm		0.119	0.133
	gpm/net MW		0.975	0.992
Steam to FGD System	K lbs/hr		0.00	0.00
Total FGD Power Consumption	kW		1,688	1,894
FGD Byproduct	lbs/hr		-	-

Appendix B
Lower-Sulfur Fuel Oil Calculations

Lower-Sulfur Fuel Oil Costs Calculations

Estimates based on 10 million gallons of fuel oil burned per year

Bailey

O&M Costs

Fuel	$/bbl	$/gal	$/year
1.0% fuel oil	$38.75	$0.9226	$9,226,190
2.3% fuel oil	$38.50	$0.9167	$9,166,667
		Diff	$59,524

Tons of SO2 Removed

oil gal/yr	oil lb/gal	Sulfur %	SO2 factor	SO2 lb/yr	SO2 tpy
10,000,000	8.34	2.30%	2	3,836,400.0	1,918.2
10,000,000	8.34	1.00%	2	1,668,000.0	834.0
				Tons Removed	1,084.2

$/ton SO2 Removed

O&M Cost	SO2 tpy Rem	$/ton Rem
$59,524	1,084.2	**$54.90**

McClellan

Fuel	$/bbl	$/gal	$/year
1.0% fuel oil	$38.75	$0.9226	$9,226,190
2.8% fuel oil	$37.75	$0.8988	$8,988,095
		Diff	$238,095

Tons of SO2 Removed

oil gal/yr	oil lb/gal	Sulfur %	SO2 factor	SO2 lb/yr	SO2 tpy
10,000,000	8.34	2.80%	2	4,670,400.0	2,335.2
10,000,000	8.34	1.00%	2	1,668,000.0	834.0
				Tons Removed	1,501.2

$/ton SO2 Removed

O&M Cost	SO2 tpy Rem	$/ton Rem
$238,095	1,501.2	**$158.60**

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October 26, 2006

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Arkansas Department of Environmental Quality
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Post Office Box 8913
Little Rock, Arkansas 72219-8913

**RE: AEP Southwestern Electric Power Company
Flint Creek Power Plant and BART Analysis
October 13, 2006 Meeting**

Dear Mr. Bates,

AEP Southwestern Electric Power Company (SWEPCO) representatives met with your staff on October 13, 2006 to discuss the results of the air modeling conducted by ADEQ in conjunction with the Flint Creek BART analysis. SWEPCO requested the meeting in order to make sure that we have a common understanding of the BART requirements, specifically as it relates to how modeling results are to be interpreted. As the result of our discussions, we are requesting ADEQ concurrence on the following issues:

1. ADEQ performed modeling results for primary particulate matter (PM) impacts indicates that the Flint Creek PM emissions do not trip the BART impact threshold values at Class 1 areas of interest to the ADEQ. Consequently, existing electrostatic precipitators at Flint Creek are BART for PM.
2. In meeting the presumptive limits of 0.15 lbs/mmBTU for SO2 and 0.23 lbs/mmBTU for NOx, SWEPCO is not required to undertake the five-factor analysis specified in the BART rulemaking. As we indicated at the meeting, it was our belief that in developing the presumptive limits, EPA may have gone through such an analysis. We can now reconfirm our beliefs based on the following language reflected in the preamble to the final regional haze rules and BART determinations (F.R. Vol. 70, No. 128, July 6, 2005 at 39131). To cite the specifics, the language in preamble section "6). What should be the presumptive limits for SO2 and NOx for utility boilers?" reads: "In addition, while States are not required to follow guidelines ("presumptive limits" - AEP amplification) for EGUs located at power plants with generating capacity of <u>less than 750 MW</u> (emphasis added), based on our analysis detailed below, we believe that States will find that these <u>same</u>

presumptive controls (emphasis added) to be highly cost effective and to result in a significant degree of visibility improvement, for most EGUs greater than 200 MW (emphasis added), regardless of the size of the plant at which they are located……. Nevertheless, our analysis indicates that these controls are likely to be among the most cost effective controls available for any source subject to BART and that they are likely to result in a significant degree of visibility improvement."

3. ADEQ's post-control CALPUFF modeling for cumulative and individual emissions of SO2, NOx, PM10 and PM2.5 indicate that visibility improvements should be realized at the Class I areas modeled. However, as we indicated at the meeting, BART is a site-specific control program and would be deemed to be satisfied if presumptive limits are met. Our BART offerings will satisfy such presumptive limits. We would also like to restate that BART and the reasonable progress goal glide slope analysis are on separate regulatory tracks and individual source BART limits are not set with the intent to solely help meet the glide slope for a Class 1 area. Achievement of reasonable progress goals for a given Class 1 area specified under the Regional Haze Rule is predicated on a cumulative effect of emissions reductions from other utility and non-utility sources covering several states.

We appreciate the effort that your staff is putting forth to meet the aggressive timelines required to implement BART. SWEPCO looks forward to your response to the above items. Should you have any questions or comments, please do not hesitate to call me at (318) 673-3595.

Sincerely,

T. Brian Bond
External Affairs Vice President

cc: Curtis Warner – AECC
Steve Cain – AECC
N.N. Dharmarajan-AEP
Mark McCorkle-ADEQ
Mary Pettyjohn-ADEQ

CFD-based Development, Design, and Installation of Cost-effective NOx Control Strategies for Coal-fired Boilers

Paper #

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ABSTRACT

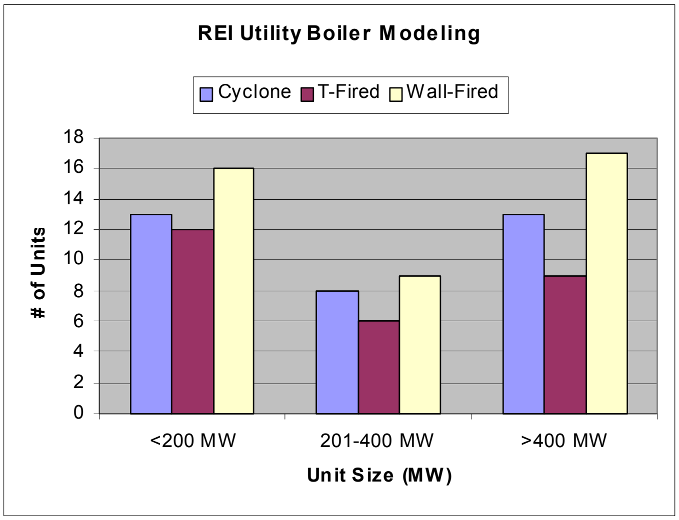
CFD modeling has found increasing use among combustion engineers in the design and evaluation of utility boiler retrofits, combustion optimization and NOx reduction technologies. This paper reviews three recent examples of combustion engineers using CFD modeling in the design and implementation of NOx reduction technologies. All three examples involve the staging of furnace combustion through the use of overfire air (OFA) to reduce NOx emissions. The first is for a 265 MW_g B&W opposed-wall pulverized coal furnace, the second for a 530 MW_g B&W opposed wall cyclone-fired boiler, and the third for a 500 MW_g B&W supercritical pulverized coal furnace fired with burners on all four walls. Furnace simulations identified locations of highest flue gas mass flows and highest CO and O_2 concentrations and were used by the combustion engineers to identify OFA port placement for maximum NOx reduction with lowest increases in unburned carbon in fly ash and CO emission. For the first two units, simulations with OFA additions predicted 34% and 80% reductions in NOx emissions, respectively, with minimal changes in CO concentration and unburned carbon. Plant CEM data for these units confirmed the accuracy of the modeling results for pre-retrofit and post-retrofit operation. For the third unit, potential overfire air configurations resulting in NOx reductions ranging from 24% to 43% are presented and impacts on CO emissions and carbon-in-fly ash are discussed.

INTRODUCTION

The electric utility industry is facing aggressive NOx reduction requirements in coal-fired furnaces. Proven NOx control technologies are available that provide a range of performance over a range of operating and capital costs. For example, Selective Catalytic Reduction (SCR) has been proven to reliably achieve 75-85% NOx reduction in a substantial number of coal fired units. However, these reductions come at high capital and operating cost. In many existing units, application of SCR is cost prohibitive and, as a result, utilities are keenly interested in more cost-effective technologies. Often the selection and application of NOx control technologies requires careful consideration of the specific unit and system-wide objectives.

CFD modeling has found increasing use in the design and evaluation of utility boiler retrofits, combustion optimization and NOx reduction technologies. For example, over the past eight years Reaction Engineering International (REI) has used in-house software created specifically for fossil-fired boilers to perform CFD simulations of more than 100 utility boilers. Engineering evaluations have been completed to describe the performance and impact of NOx reduction technologies such as staging and overfire air, low NOx burners, visciated air and air preheating, co-firing of opportunity fuels, fuel blending, Rich Reagent Injection (RRI), Selective Non-catalytic Reduction (SNCR), gas reburning, and Fuel Lean Gas Reburning (FLGR). Boilers modeled range in size from 34 MW to 1300 MW and include cyclone, tangential, wall, vertical and stoker firing systems. Figure 1 shows the unit size distribution of cyclone, tangential and wall-fired units modeled by REI over the past eight years. The majority of these units were coal-fired, requiring modeling software capable of accounting for turbulent two-phase mixing, equilibrium (e.g., CO_2, O_2) and finite-rate (e.g., NOx) gas-phase chemical reactions, heterogeneous coal particle reactions (devolatilization and char oxidation) and radiant and convective heat transfer.

Figure 1. Distribution of utility boilers modeled by REI.



AEP Pro Serv has had experience in the design and installation of over 30 NOx reduction retrofits in various types of coal fired furnaces. These NOx reduction systems include OFA, burner alterations, and water injection schemes. AEP has developed a strong experience base with CFD analysis and has found it to be an effective tool in evaluating vendor claims, guiding system design and equipment integration, as well as for unit troubleshooting.

In the hands of experienced combustion and CFD engineers, CFD modeling provides a valuable tool to evaluate impacts of potential burner and furnace alterations on NOx emissions, unburned carbon in fly ash, CO emissions and waterwall corrosion. It is particularly useful in the evaluation of “one-of-a-kind” systems in which the experience base is limited. This paper describes how CFD modeling has been utilized in this manner to evaluate and design cost effective NOx reduction strategies applied to three coal-fired utility boilers.

Approach

The evaluation described here requires the construction of a CFD model description of a unit under “baseline” operation, representative of typical full load operating conditions. Confidence in input descriptions and model validity is achieved by comparing these results with observations of unit performance that can include NOx and CO emissions, unburned carbon in ash, steam-side heat transfer, local temperatures and deposition patterns. Parametric simulations are then completed to evaluate impacts of burner alterations, combustion air optimization, and water injection. The simulations were carried out in series so that simulation results could be utilized to make incremental improvements to the designs. Based on the results of all simulations, specific burner modifications, OFA port arrangements, and water injection designs are recommended. The following two sections describe this approach in additional detail. A description of the CFD model is first given followed by a discussion of the approach used to develop a CFD model of each unit.

CFD Model

The REI combustion models[1] employ a combination of Eulerian and Lagrangian reference frames. The flow field is assumed to be a steady-state, turbulent, reacting continuum field that can be described locally by general conservation equations. The governing equations for gas-phase fluid mechanics, heat transfer, thermal radiation and scalar transport are solved in an Eulerian framework. The governing equations for particle-phase mechanics are solved in a Lagrangian reference frame. The overall solution scheme is based on a particle-in-cell approach.[2]

Gas properties are determined through local mixing calculations and are assumed to fluctuate randomly according to a statistical probability density function (PDF), which is characteristic of the turbulence. Turbulence is typically modeled with a two-equation k-ε model.[3] Gas-phase reactions involving major species are assumed to be controlled by mixing rates and local chemical equilibrium - as opposed to pollutant species such as NOx and CO, which require appropriate descriptions of finite rate chemistry.

Particle mechanics are computed by following the mean path for a discretized group of particles, or particle cloud, in a Lagrangian reference frame. Particle reaction processes include coal devolatilization, char oxidation, and gas-particle interchange. The dispersion of particles within the cloud and cloud expansion are based on statistics gathered from the turbulent flow field. Heat, mass, and momentum transfer effects are included for each particle cloud. The properties of the particle cloud are computed from a statistical average over the particles within the cloud. The properties of the local gas field are computed with an analogous ensemble averaging procedure. Particle mass and momentum sources are converted from a Lagrangian to an Eulerian reference frame by considering the residence time of each particle cloud within the computational cells.

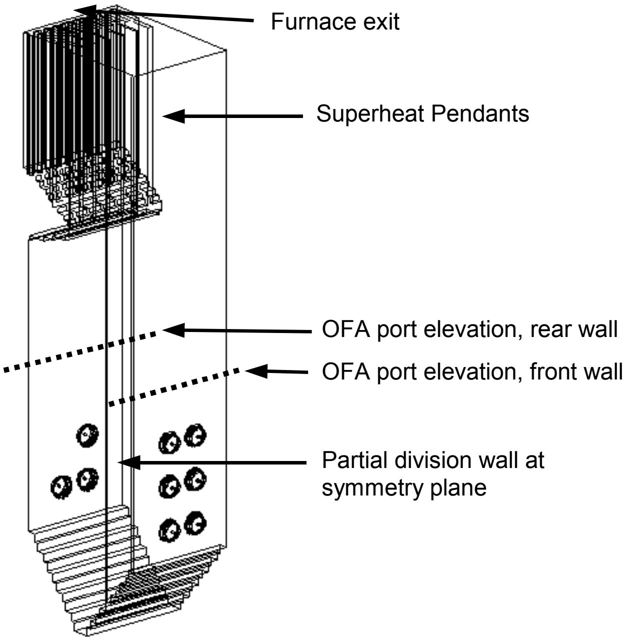
The radiative intensity field and surface heat fluxes are calculated using the discrete ordinates method. Effects of variable surface properties and participating media (gas, soot and particles) are included.

This paper reviews three recent examples of CFD modeling used in the design and implementation of OFA systems for an opposed-wall PC unit, a cyclone-fired unit, and a four-wall-fired PC unit.

OPPOSED WALL-FIRED PC-FIRED BOILER OFA STUDY

CFD modeling was used to provide a conceptual design and to evaluate NOx reduction performance of an overfire air (OFA) system in a 265 MWg B&W, subcritical, opposed-wall, pulverized coal-fired furnace. The furnace is fitted with eighteen Babcock Power (formerly Riley Stoker) CCV low NOx burners and baseline NOx emissions are approximately 0.6 lb/MMBtu. It was expected that OFA ports would be installed on both the furnace front and rear walls. Making use of symmetry, a 650,000 computational cell half-furnace model was developed. Basic features of the model are shown in Figure 2. Only three of the six front wall burners (for the half furnace model) are directly opposed by rear wall burners.

Figure 2. Schematic of half furnace model for opposed wall fired boiler showing OFA port elevations.



The goal of the CFD modeling study was the optimization of the overall OFA system design to minimize NOx emissions without increasing CO emissions or carbon in fly ash.

OFA system design considerations were the horizontal plane OFA port placement, port geometry, air jet velocity, appropriate burner size adjustments, and the level of furnace staging. Before beginning modeling evaluations, AEP Pro Serv engineering worked with modeling engineers to identify feasible locations for the OFA ports on the unit.

An initial baseline simulation was performed to model the current operating condition and to verify the accuracy of the model. The baseline simulation predicted a furnace full load NOx emission of 0.58 lb/MMBtu, unburned carbon in fly ash (UBC) of 8%, and a model exit CO of 85 ppm. The CO level can be expected to decrease through the convective pass. With the exception of the unburned carbon level, which was a few percent higher than plant measurements, these values compared favorably with observed furnace operation.

Based on consideration of residence time and construction constraints, an elevation ten feet above the top row of burners was selected for an initial OFA height. AEP Pro Serv engineers then examined simulation descriptions of CO concentration and upward flue gas flow to arrive at an effective port configuration. In this evaluation, the placement of the ports was the only variable used to bias the air injection and effectively target the pockets of fuel rich flow above the burner. Although practical limitations prevented a more involved analysis in this situation, port geometry and flowrate are also options for tailoring OFA implementations.

Figure 3 shows the location of high CO concentrations and upward flue gas mass flux, respectively, at the proposed OFA port elevation ten feet above top burners. High CO is present near the rear wall and near the furnace center. The two lobes nearest the front wall originate from the top front wall burners below. The upward flue gas flow is highest in the rear half of the furnace, at least partially since there are no upper rear wall burners opposing the upper front wall burners. In the region above the upper front wall burners, the burner swirl results in downward mass flow at this elevation. Although the flow field shown in Figure 3 is for an unstaged furnace and could be expected to change somewhat with furnace staging, it provides a reasonable basis for locating OFA ports.

Based on the predicted flow field information above, AEP Pro Serv engineers determined a preliminary OFA port layout. The preliminary design is shown in Figure 4. Since high CO regions are nearer the rear wall than the front wall and the upward mass flow is higher in the rear half of the furnace than in the front half, more ports were located on the rear wall than on the front. In addition, it was felt that no OFA port was necessary in the center of the front wall where the predicted flue gas flow is downward, as this would result in the introduction of oxygen rich air into the burner zone. Ports were sized for an OFA jet velocity of 170 ft/s with the lower furnace staged to 0.9. Interlaced ports as in Figure 4 rather than directly opposed OFA jets often help penetration.

Figure 3. Plots of CO concentration (left) and upward flue gas mass flux (right) at proposed OFA elevation.

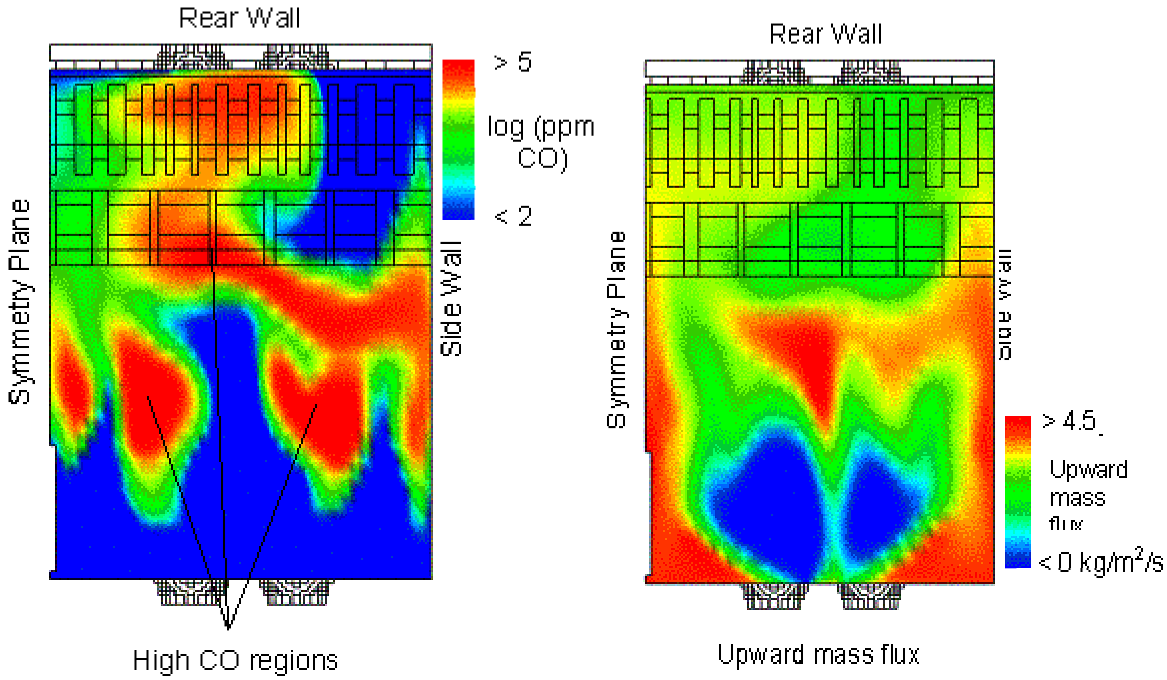
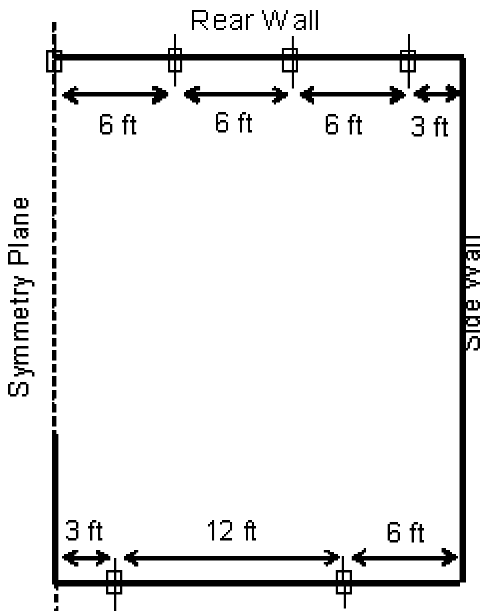


Figure 4. Schematic of proposed OFA port locations on front and rear walls.



A portion of the secondary burner air was diverted to the OFA ports and consequently, the diameters of the primary coal pipe and secondary air inlet were altered to achieve a specific OEM-recommended secondary to primary air velocity ratio for the CCV burners in this furnace. A summary of predicted results for the baseline and initial OFA cases is shown in Table 1. Key parameters included are the level of furnace staging in the burner zone, burner alterations made to retain recommended air velocity ratios, and predicted NOx, UBC and CO concentrations. NOx reductions greater than 30% were predicted with OFA, but UBC and CO concentrations also increased significantly. Note that the NOx, UBC and CO concentrations are at the exit of the computational model, approximately after the first section of superheat pendants and directly above the rear wall of the radiant furnace. NOx chemistry is substantially frozen beyond this point due to the low flue gas temperature and unburned carbon will decrease very little. However, CO concentrations can be expected to decrease significantly through the back pass of the boiler.

A second OFA simulation was performed in order to find a configuration that would produce less of an increase in carbon in fly ash. In the second OFA configuration, the level of furnace staging was decreased to a stoichiometric ratio of 0.95 from 0.90 in the initial OFA simulation. This time only the primary burner diameter was altered to maintain the recommended secondary to primary air velocity ratio and the OFA ports were downsized to maintain a velocity of 170 ft/s. Predicted NOx remained low, at 0.38 lb/MMBtu, with only a moderate increase in carbon in fly ash - from 8% in the baseline simulation up to 13%. Although the simulations indicated that implementation of this configuration in the actual furnace would result in an increase in unburned carbon, the baseline UBC prediction appeared somewhat high suggesting that the final level could be lower than the prediction also, allowing the UBC to remain within acceptable levels.

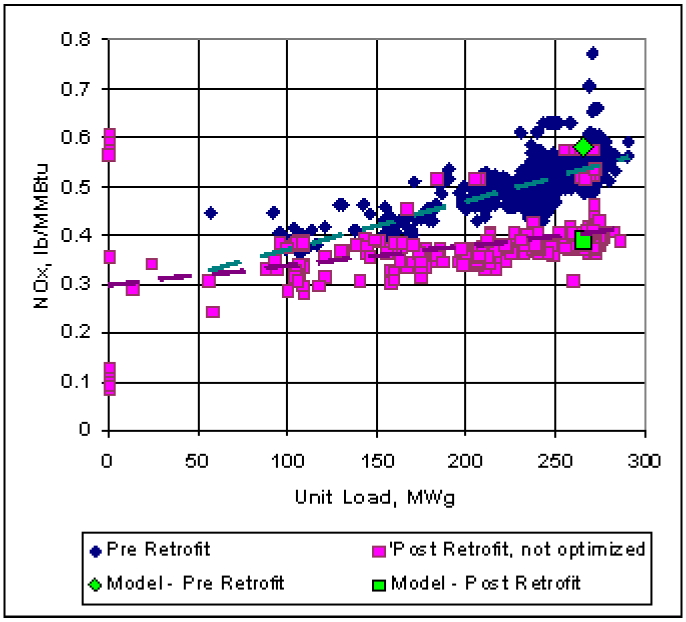
Results from these three CFD simulations of this furnace were used by AEP Pro Serv engineering to select an appropriate OFA system design. An overall summary of the simulations is shown in Table 1. Although NOx is reduced to the same level for both OFA configurations, the increase in carbon in fly ash is less severe for the revised OFA configuration. The furnace is less deeply staged in the revised OFA configuration, but burner alterations also have some impact on NOx. Although CO increased for both OFA configurations, much of the CO can be expected to burn to completion in the convective pass.

Table 1. Summary of simulation results showing the effect of different OFA designs.

	Baseline	**Initial OFA**	**Revised OFA**
Furnace Staging	None	0.90	0.95
Burner Alterations	None	Prim. & Sec.	Primary
Predicted NOx (lb/MMBtu)	0.58	0.39	0.38
Predicted Carbon in Fly Ash	8%	20%	13%
Predicted CO (furnace exit)	85 ppm	801 ppm	1000 ppm

The installation of the OFA design, as modeled, was completed in the Spring of 2002. Although AEP Pro Serv has not yet fully optimized the system, the NOx emission rates are in agreement with the modeling effort and both stack CO emissions (<50 ppm) and unburned carbon in flyash levels (5-10%) are within acceptable ranges. A comparison of the NOx emission rates, prior to and after the OFA retrofit is illustrated in Figure 5.

Figure 5. Comparison of predicted and reported NOx emission rates before and after OFA retrofit.



CYCLONE FURNACE OFA STUDY

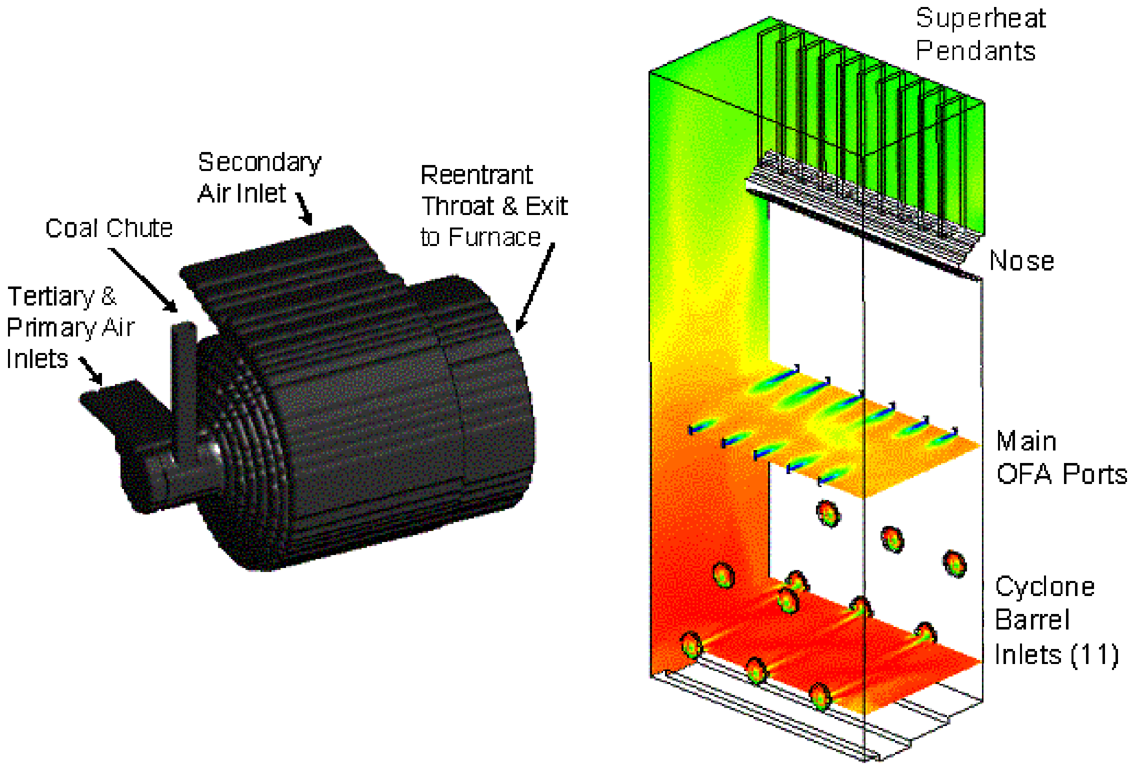
CFD modeling was used by AEP Pro Serv engineering to provide a conceptual design and to evaluate NOx reduction performance of an overfire air (OFA) system in a 530 MWg B&W, supercritical, opposed-wall, cyclone-fired furnace. The furnace is fitted with eleven 10-foot diameter cyclones with radial primary burners. The cyclones are oriented 2 over 3 on the furnace front wall and 3 over 3 on the rear wall. The baseline NOx emissions were dependent upon the fuel source and the usage of water injection within the cyclone barrels. The CFD modeling effort was performed utilizing a current typical coal blend of 60% sub-bituminous PRB coal and 40% eastern bituminous coal. The baseline full load NOx emission for this fuel blend is approximately 1.8 to 1.9 lb/MMBtu. Prior to the application of OFA, this unit utilized water injection in the cyclone barrels to control visible opacity levels otherwise due to elevated NO_2 levels at the stack. Limited data was available with the specified fuel blend and without water injection.

The range of OFA elevation options were significantly greater than those limiting the OFA application for the previously discussed pulverized coal fired boiler, while still having sufficient residence times to achieve burnout above the OFA level. The selection of modeled OFA options was determined by practical limitations created by buckstay elevations. Two OFA elevation options, approximately nineteen and twenty-six feet above the top cyclone centerlines, were considered. These options would provide adequate residence time above the ports for completion of combustion.

Normal operation of a cyclone furnace results in a layer of slag on the cyclone's barrel surfaces and the burning of nearly all of the coal on the surface of the slag layer. As such, the model study was conducted in two phases. First, the cyclone barrels were modeled with combusting particles. The cyclone barrel model consisted of ~350,000 computational cells. Secondly, the output of the cyclone barrel model, which included negligible organic solids, was applied to a full furnace model as 100% gas phase. A 750,000 computational cell full-furnace model was developed. Basic features of the models are shown in Figure 6.

The goal of the CFD modeling study was the optimization of the overall OFA system design to maximize the reduction in furnace NOx emission while minimizing adverse effects such as increased CO emissions and increased carbon in fly ash. OFA system design considerations were the horizontal plane OFA port placement, port geometry, air jet velocity, appropriate cyclone combustion airflow distribution adjustments, and the level of staging within the cyclone barrels.

Figure 6. Illustrations of cyclone barrel and full furnace models.



An initial baseline simulation was performed to model the current operating condition and to verify the accuracy of the model. The baseline simulation predicted a furnace full load NOx emission of 1.96 lb/MMBtu and a model exit CO of 217 ppm. The CO level can be expected to decrease through the convective pass. Because the furnace model considers only gas phase flows, no unburned carbon in ash predictions were provided. The predicted emission values were in line with observed furnace operation.

The staged cyclone barrel simulations were performed at a stoichiometric combustion air ratio of 0.9, while maintaining the flow in the primary burner at the same rates used under normal baseline, unstaged conditions. A comparison of the barrel model results is illustrated in Table 2. Notable are the predicted 13% reduction in the cyclone barrel NOx production and the 97% increase in the CO concentration at the barrel exit plane. These results were then applied to the furnace model under each of three OFA port arrangements and OFA jet velocities of 300 ft/sec. The baseline furnace model mass flow distributions actually suggested that this front to rear wall port arrangement should be reversed; however, furnace structural concerns with such a configuration resulted in the ports being located above the cyclone barrel centerlines. The staggered OFA pattern was also incorporated to achieve deeper jet penetrations and improved mixing patterns.

Table 2. Cyclone Barrel Model Results for Baseline and Staged Operation.

	Baseline	**Staged (SR = 0.9)**
Barrel Exit Temperature (^oF)	2897	2930
Barrel Exit CO (ppm)	36,680	72,214
O_2 (%, wet)	5.49	4.01
Burnout (%)	98	98
NO ppm @ 3% O_2	508	440
lb NOx / MMBtu	0.68	0.59

The results of the baseline and the staged furnace firing OFA options are presented in Table 3. The predicted average furnace exit NOx concentration for the baseline case was 1.96 lb-NOx/MMBtu. The initial staged furnace case (OFA Case1) resulted in a significant decrease in NOx emissions (~80%), but also a two-order of magnitude increase in predicted furnace exit CO concentrations. Note that this is not the expected furnace CO emission as the CO will continue to oxidize through the boiler backpass, but is significantly higher than the predicted baseline furnace CO levels. Staging also resulted in a predicted decrease in average flue gas temperature at the furnace exit.

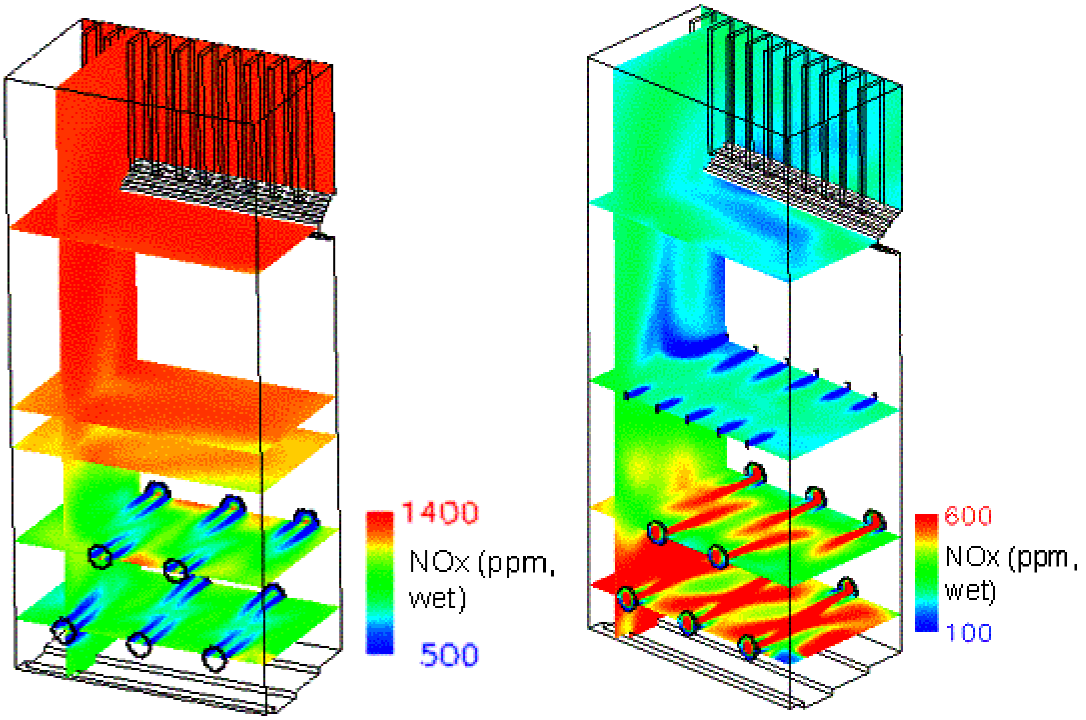
Table 3. Cyclone Furnace Model Exit Predictions

	Baseline	**OFA Case1**	**OFA Case 2**	**OFA Case 3**
Temperature (^{o}F)	2438	2299	2340	2364
CO (dry, ppm)	217	2093	413	324
O_2 (dry, %)	2.79	2.93	2.80	2.80
NO @ 3% O_2 (ppm)	1467	264	277	355
lb NOx / MMBtu	1.96	0.35	0.37	0.47

Figure 7 shows NOx concentration profiles in the furnace for the baseline and initial OFA (OFA Case 1) operations. Under the unstaged baseline conditions, NOx concentration continues to increase as a function of furnace height from the barrel inlet region in the lower furnace to the nose region. This is due to the continued formation of thermal NO as the fuel lean, high temperature combustion products mix in the lower furnace. The highly stratified species concentrations present at the barrel exit mix in the lower furnace, providing a flue gas with more uniform characteristics, although some species concentration gradients continue to exist due to non-uniform flow patterns in the furnace. NOx formation rates are greatest in the lower regions of the furnace where temperatures are highest. As heat is extracted through the furnace walls, gas temperatures decrease resulting in lower thermal NO formation rates.

In the NOx concentration profiles for OFA Case 1 in Figure 7, high NOx concentrations are evident in the lower portion of the boiler consistent with the concentrations exiting the cyclone barrels. However unlike the baseline case where NOx concentrations increased in the furnace, NOx concentrations in the staged case drop rapidly in the lower furnace. This is due to two factors. The first is that the fuel rich environment in the lower furnace inhibits NOx formation. The second is that the fuel rich environment also allows for reburning conditions to exist that reduce NOx formed in the cyclone barrels. The combination of these two effects results in a significant drop in NOx concentrations at the furnace exit. It is interesting to note that the same high temperatures that contribute to NOx formation under fuel lean conditions also enhance the high NOx reduction rates under fuel rich conditions.

Figure 7. Predicted NOx concentration profiles for the baseline case and OFA Case 1.

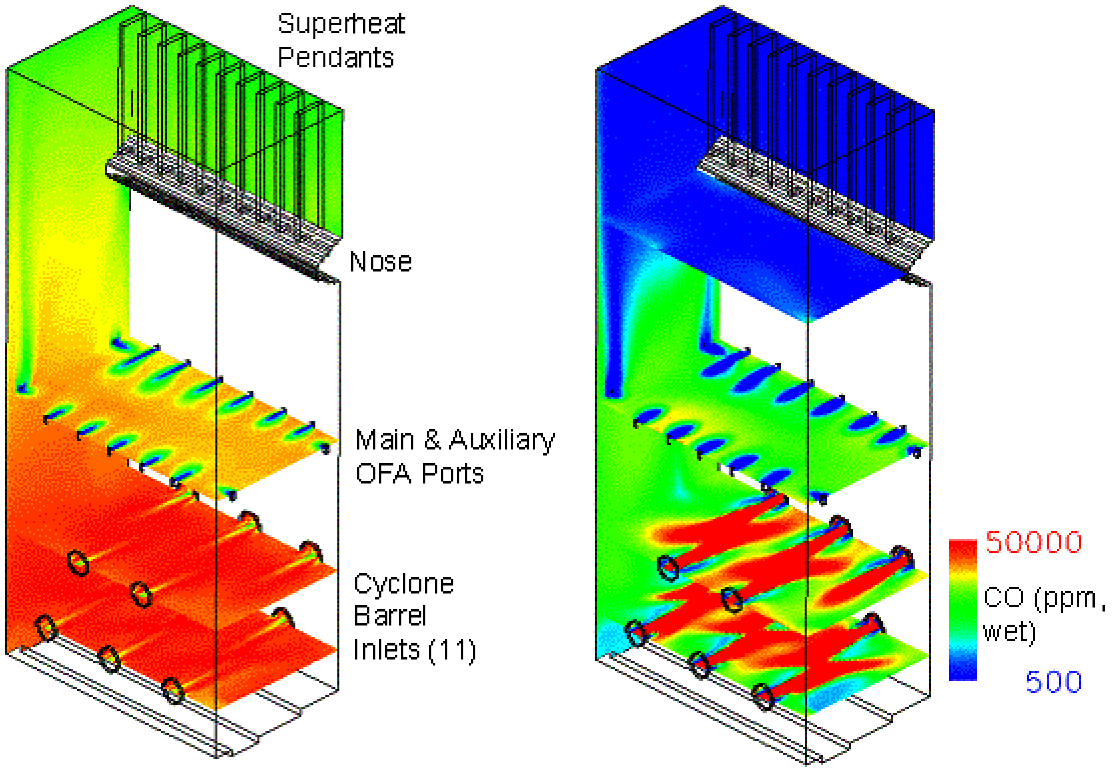


Baseline **OFA Case 1**

The simulation results of OFA Case 1 indicated that there were CO pockets in the corners of the furnace that persisted through the furnace exit. As a result, the OFA injection scheme was changed to include four auxiliary ports near the corners on the side walls of the furnace (see Figure 8). The amount of flow introduced through the auxiliary OFA ports equated to 16% of the total OFA flow, 4% per port. The jet velocity through these ports was at a significantly lower velocity, 100 ft/sec, by utilizing different style port geometry. This produced reduced OFA jet penetrations from these ports in order to effectively reduce the predicted CO concentrations in the corners of the furnace. The front and rear wall jet velocities were proportionately reduced to 254 ft/sec (from 300 ft/sec).

The results of the OFA Case 2 simulation are shown in Table 3 and indicate a significant reduction in predicted furnace exit CO concentration (2093 versus 413 ppm at the model's exit plane) with only a minimal change in NOx levels (0.35 versus 0.37 lb/MMBtu). The highest CO pockets still remained in the corners of the furnace (see Figure 12). These results were considered to be very positive and became the basis of the AEP Pro Serv OFA design that was installed in the Spring of 2002.

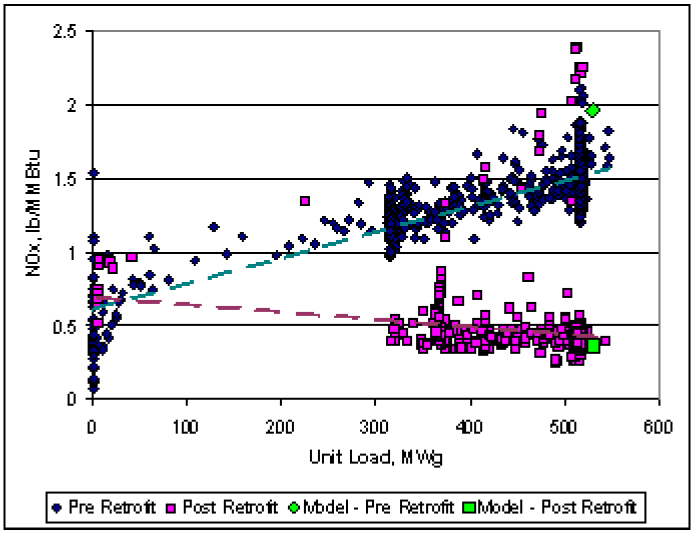
Figure 8. Schematic of OFA Case 2 showing main and auxiliary OFA ports (left) and predicted CO concentration (left).



In order to assess the sensitivity of the unit CO and NOx concentrations, a third OFA design was also modeled. In OFA Case 3, the same OFA configuration used in OFA Case 2 was implemented at a lower elevation. The results summarized in Table 3 indicate that the lower port configuration did further reduce furnace exit CO levels (413 versus 324 ppm), but at the expense of increased NOx levels (0.37 versus 0.47 lb/MMBtu). AEP Pro Serv engineering determined not to pursue this design in favor of the OFA Case2 design.

Figure 9 illustrates CEM data representative of operation before and after the installation of the OFA system. While the modeling results had indicated surprisingly good performance for the OFA design, the resultant full load NOx emissions on the unit under design conditions have validated the model predictions. This design has also resulted in stack CO concentrations of generally less than 50 ppm and average carbon in flyash levels on the order of 10% or less.

Figure 9. Comparison of predicted and reported NOx emission rates before and after OFA retrofit.



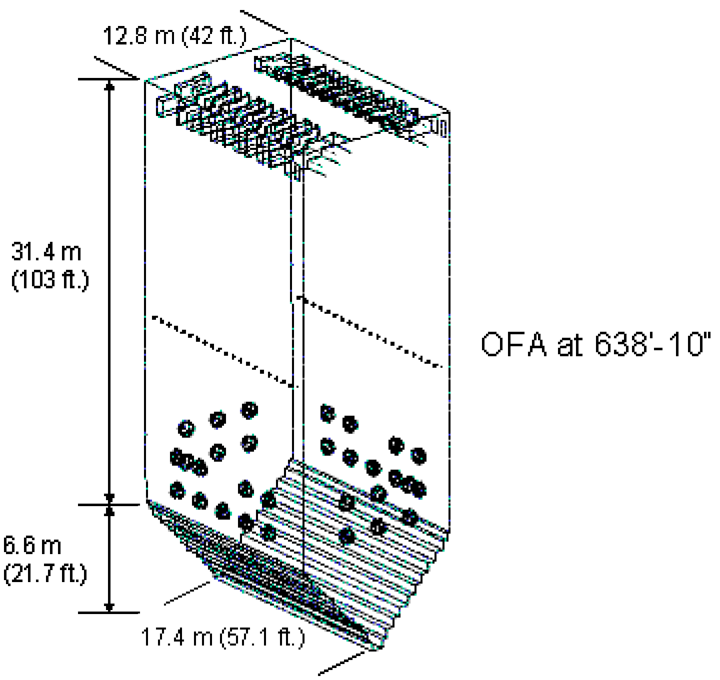
The actual OFA system was designed to achieve slightly deeper staging levels than the modeled 0.9 stoichiometric combustion air ratio. Firing under such conditions in the field has demonstrated some additional NOx control without adverse CO or carbon in ash effects.

FOUR WALL FIRED PC-FIRED BOILER OFA STUDY

This four-wall-fired furnace is a 500 MW, B&W, supercritical, double reheat steam generator. The unit has a total of thirty circular burners, distributed among all four furnace walls, utilizing Babcock Power CCV low NOx burner technology. The original secondary air diverters have been replaced with Babcock Power's updated flame stabilizing rings. The burners are distributed symmetrically between the front and rear walls with nine burners on both walls (4 over 5). Similarly there are six burners on each side wall (3 over 3). The unit was designed with flue gas recirculation (FGR). A schematic of the lower furnace with the proposed OFA port elevation is shown in Figure 10. Baseline NOx emissions and CO emissions are approximately 0.37 lb/MMBtu and 3,630 ppm, respectively.

The goal of the CFD modeling study was the optimization of an OFA system design to maximize the reduction in furnace NOx emission while minimizing adverse effects such as increased CO emissions and increased carbon in fly ash. OFA system design considerations included the horizontal plane OFA port placement, port geometry, and air jet velocity. Before beginning modeling evaluations, AEP Pro Serv and SAVvy Engineering worked with modeling engineers to identify feasible locations for the OFA ports on the unit.

Figure 10: Schematic of the four-wall-fired boiler showing proposed OFA elevation.

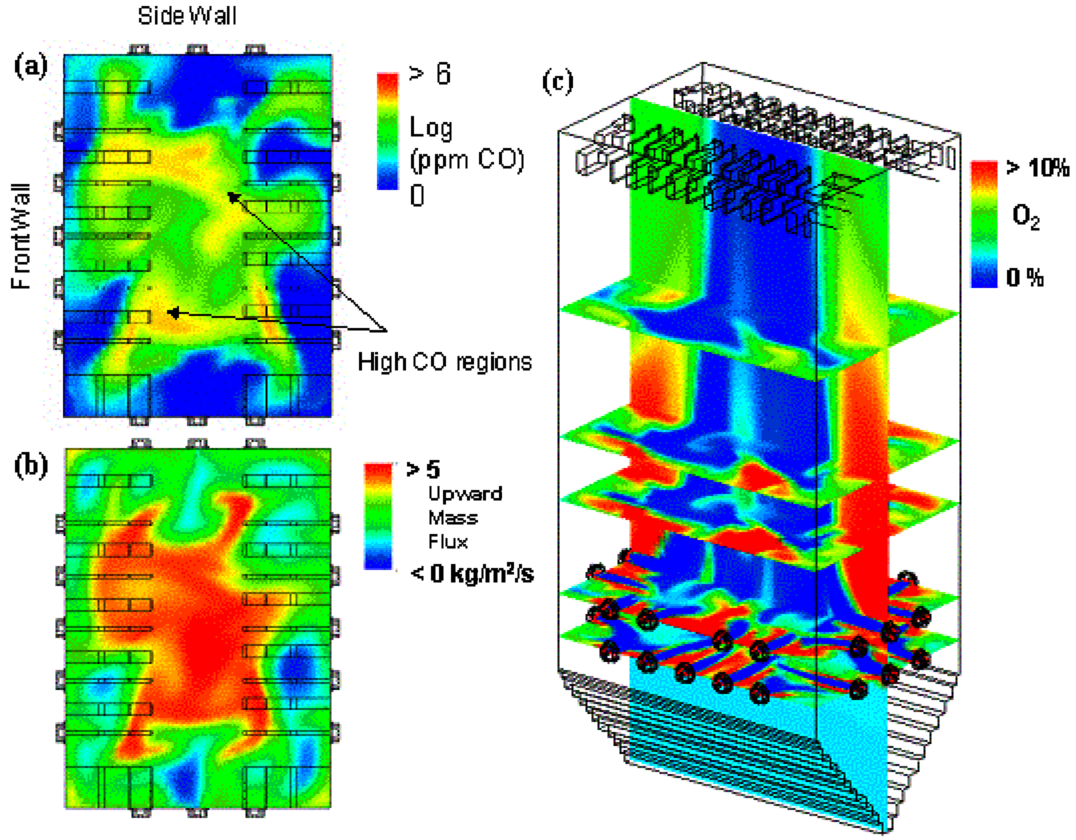


It was expected that OFA ports would be installed on both the furnace front and rear walls. An elevation 638'-10" was suggested for OFA port horizontal centerline; this would provide adequate residence time above the ports for completion of combustion.

An initial baseline simulation was performed to model the current operating condition and to verify the accuracy of the model. The baseline simulation predicted a furnace full load NOx emission of 0.37 lb/MMBtu, unburned carbon in fly ash (UBC) of 12.5%, and a model exit CO of 3,630 ppm. The CO level can be expected to decrease as it moves through the convective pass. With the exception of the unburned carbon level, which was a few percent higher than plant measurements, these values were in line with observed furnace operation.

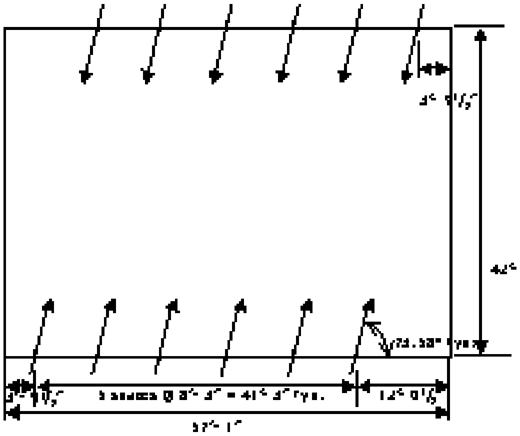
To evaluate placement of OFA ports in the horizontal plane at an elevation 638'-10", AEP Pro Serv considered the baseline CO concentration and upward flue gas flow. If the CO and flue gas flow fields are not uniform at this elevation, OFA air will be most effective if concentrated in higher CO and flue gas mass flow regions. Figure 11 (a) and (b) show the location of high CO concentrations and upward flue gas mass flux at the proposed OFA port elevation. High CO is present near the furnace center and left side wall. Similarly, high upward mass flux is present near the furnace center. Upon air and fuel injection, uniformly distributed mass flows from the burners at all four side walls meet at the furnace center and are pushed upward. In addition, hopper injection of FGR enhances this chimney effect. This results in a relatively stratified flow pattern as shown in the plot of O_2 distribution (Figure 11 (c)). Although the flow field shown in Figure 11 is for an unstaged furnace and could be expected to change somewhat with furnace staging, it provides a reasonable basis for locating OFA ports.

Figure 11. CO concentrations (a) and upward flue gas mass flux (b) at proposed OFA elevation, and O2 distribution (c) at various horizontal and vertical planes in the furnace.



Based on the predicted flow field information above, AEP Pro Serv engineering determined a preliminary OFA port layout (OFA1) at a proposed elevation 638’-10”. The preliminary design is shown in Figure 12. Since CO concentration and upward mass flow peak in the center of the furnace, ports were located only on the front and rear walls to minimize the number of ports and to achieve more effective penetration to the furnace center. In addition, the ports were offset more from one side wall than the other to improve mixing. A jet angle of 73.58 degrees was used. Ports were sized for an OFA jet velocity of 185 ft/s with a lower furnace stoichiometric ratio of 0.92.

Figure 12: Schematic of proposed OFA port locations on front and rear walls (OFA1).



A summary of predicted results for the baseline and OFA cases is shown in Table 4. Key parameters included are the level of burner stoichiometry, and predicted NOx, UBC and CO concentrations. NOx reductions over 35% were predicted with OFA1, but UBC and CO concentrations also increased significantly from the baseline results (55% and 161%, respectively). Note that the NOx, UBC and CO concentrations are at the exit of the computational model. NOx concentrations will not change much beyond this point due to low flue gas temperatures. Unburned carbon can decrease slightly, but CO concentrations can be expected to decrease significantly through the back pass of the boiler.

Table 4. Summary of simulation results showing the effect of different OFA designs.

	Baseline	**OFA1**	**OFA2**	**OFA3***	**OFA4+**
Burner Stoichiometry	1.14	0.92	0.92	0.92	0.92
Predicted NOx (lb/MMBtu)	0.37	0.24	0.27	0.21	0.28
Predicted Carbon in Fly Ash	12.5%	19.4%	16.2%	20.6%	9.6%
Predicted CO (ppm, at furnace exit)	3,630	9,490	4,808	11,488	2,991

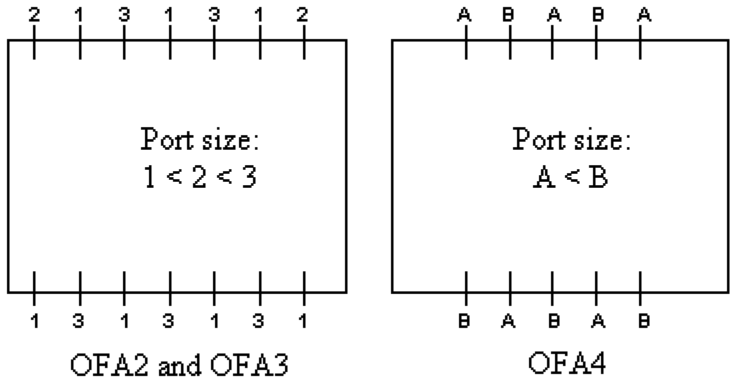
* In OFA3, flow rate of flue gas recirculation was reduced by half while the other operating conditions were the same as in OFA2.
\+ In OFA4, 30 ° coal spreader was implemented in the simulation.

The additional OFA port configurations shown in Figure 13 were also investigated. A second OFA simulation (OFA2) was performed in order to find a configuration that would produce less of an increase in CO emission while limiting NOx emission. In OFA2 configuration, a combination of port location as well as biased air jet velocities through the ports were utilized and straight injection was employed. Three different sizes of ports were located alternately with smaller ports at the wing on the front and rear walls (1 is smallest and 3 is largest port size). Interlaced arrangement such as OFA2 often provides effective mixing. Predicted NOx remained low (0.27 lb/MMBtu) with a slight increase from OFA1, but the predicted increase in carbon in fly ash was moderate by 30% over the baseline. Although the simulations indicated that implementation of this configuration in the actual furnace would result in an increase in unburned carbon, the baseline UBC prediction appeared somewhat high suggesting that the final level could be lower than the prediction also.

Figure 14 shows the plots of CO concentration at the horizontal exit plane. Baseline, OFA1, and OFA2 consistently show high CO concentration in the center of the furnace where the high upward mass flux exists. Upward mass flux is high since flows from burners located at all four walls meet at the center and are pushed upward. In addition, up-fired FGR helps push mass upward faster, which hinders effective mixing of OFA. To better understand the effect of FGR, OFA3 case used half of the original FGR flow rate with the same OFA arrangement as in OFA2. Predicted NOx was even lower at 0.21 lb/MMBtu, because with reduced upward mass flux, longer residence time exists in fuel-rich region that helps limit NOx production. However, longer residence time in fuel-rich region resulted in significantly higher CO concentration and UBC at the furnace exit.

In OFA4, the wing OFA ports were removed from both front and rear walls, as shown in Figure . By concentrating air flow to the center of the furnace, OFA can be utilized more efficiently for CO oxidation, since there is not much CO concentration near side walls at the exit as shown in Figure . In addition, 30° coal spreader was implemented to help reduce UBC. Predicted NOx remained low (0.28 lb/MMBtu), while CO emission and UBC were also reduced as shown in Table 4.

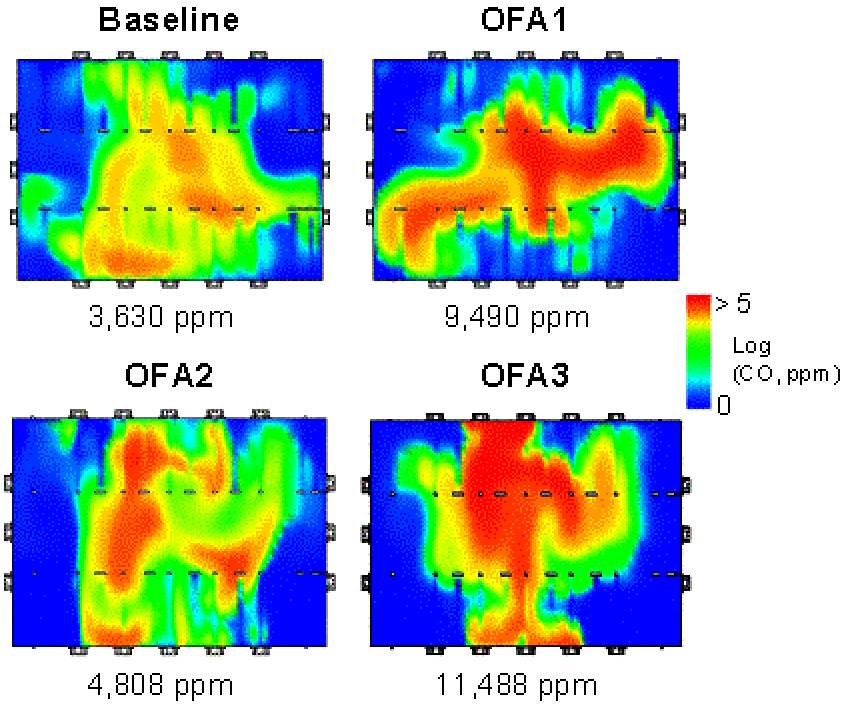
Figure 13: Proposed OFA lay outs for OFA2, OFA3, and OFA4.



OFA2 and OFA3

OFA4

Figure 14: Plot of CO concentration at the horizontal exit plane.



As illustrated by these results, AEP Pro Serv engineering and REI have been able to use CFD tools to select an effective OFA system design. For the final OFA configuration (OFA4), key parameters including NOx, UBC, and CO emission were reduced by 24%, 23%, and 18%, respectively, from the pre-retrofit configuration.

CONCLUSIONS

Three examples have been cited to illustrate the approach and effectiveness of using CFD in the design and implementation of the overfire air NOx reduction technology in coal-fired utility boilers. Both studies were conducted using REI's in-house CFD software specifically developed to account for all relevant combustion processes during coal combustion, including the formation and destruction of nitrogen oxides.

CFD simulations of a 265 MW_g B&W opposed-wall fired pulverized coal furnace fitted with Babcock Power CCV low NOx burners have been used by AEP Pro Serv to identify an OFA system design that will maximize the reduction in furnace NOx emissions while minimizing adverse effects such as increased CO emissions and increased carbon in fly ash. Modeling results showed NOx reductions over 30% could be achieved with either of two OFA designs, one with the boiler operating at a stoichiometric ratio of 0.90, the other at 0.95. Although NOx is reduced to the same level for both OFA configurations, the increase in carbon in fly ash is less severe for the higher stoichiometric ratio OFA configuration. The furnace is less deeply staged in this case, but burner alterations also have some impact on NOx and appear to compensate for the difference in furnace staging. Although predicted furnace exit CO increased for both OFA configurations over the baseline, much of this CO has been shown through field data to be oxidized in the boiler convective pass.

CFD simulations of a 530 MW_g B&W opposed-wall, cyclone-fired furnace with eleven 10 foot diameter cyclones have been used by AEP Pro Serv to identify an OFA system design that will significantly reduce in furnace NOx emission while minimizing adverse effects such as increased CO emission and increased carbon in fly ash. Modeling results showed NOx reductions over 75% could be achieved with the resultant OFA design with a 20% difference between two OFA elevation options. Although predicted furnace exit CO increased for the OFA configuration over the baseline, much of this CO differential has been shown through field data to be oxidized in the boiler convective pass.

CFD simulations of a 500 MW B&W, supercritical, four wall-fired pulverized coal furnace fitted with Babcock Power CCV low NOx burners have been used by AEP Pro Serv to identify an OFA system design that will maximize the reduction in furnace NOx emission while minimizing adverse effects such as increased CO emission and increased carbon in fly ash. Modeling results showed NOx reduction over 20% could be achieved while carbon in fly ash and CO emissions were reduced by 23% and 18%, respectively, with OFA4 design. Although NOx is reduced more in OFA1, OFA2, and OFA3 configurations, the increases in carbon in fly ash and in exit CO over the baseline are severe showing 30 – 65% and 32 – 216% increases, respectively. However, much of the predicted furnace exit CO would be oxidized in the boiler convective pass.

For the first two examples, field-testing and optimization performed by AEP Pro Serv engineering confirmed the CFD predictions of NOx reduction and demonstrated the importance and value of accurate CFD modeling when combined with combustion engineering expertise to successful in-furnace NOx control designs. The CFD modeling results were shown to be very reliable, and are considered essential to optimal design development. OFA systems for the third example are not yet implemented.

ACKNOWLEDGMENTS

The OFA modeling work described herein was supported by funding from American Electric Power (AEP). AEP Pro Serv provided engineering management, technical direction and optimization of the implemented OFA design. Some of the modeling results presented here for the pc-unit were previously published in an ASME paper[4] and are used here with permission of ASME.

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KEY WORDS

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BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION

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1. INTRODUCTION

Domtar Industries Inc. (Domtar) owns and operates a kraft paper mill located at 285 Highway 71 South in Ashdown, Arkansas (the Ashdown Mill). The Ashdown Mill is a major source as defined in Arkansas Pollution Control and Ecology Commission (ADP&E) Regulation 26, *Regulations of the Arkansas Operating Air Permit Program*, and currently operates under the authority of Arkansas Department of Environmental Quality (ADEQ) Operating Air Permit 0287-AOP-R6, which was issued on July 12, 2006.

The ADEQ has determined that the Ashdown Mill operates two emission units – No. 1 and No. 2 Power Boilers – that are eligible to be regulated under the Best Available Retrofit Technology (BART) provisions of the U.S. Environmental Protection Agency's (EPA) Regional Haze Rule in Title 40 of the Code of Federal Regulations (40 CFR) Part 51. BART is the primary mechanism identified for regulating haze-forming pollutants from stationary sources for the first implementation period under the Regional Haze Rule. The ADEQ has also determined, based on air dispersion modeling, that emissions from the Ashdown Mill BART-eligible source contributes to visibility impairment at a federally protected Class I area. Therefore, Domtar has prepared this report to document its BART determination in accordance with *Appendix Y to Part 51 – Guidelines for BART Determinations Under the Regional Haze Rule* (the BART Guidelines).

An overview of the Regional Haze Rule and BART Guidelines is provided in Section 1.1. Descriptions of the Ashdown Mill's BART-eligible emission units are included in Section 2. Section 3 describes the BART applicability analysis completed by the ADEQ for the Ashdown Mill BART-eligible source. Domtar's BART determination analysis is included in Section 4.

1.1 OVERVIEW OF REGIONAL HAZE RULE AND BART GUIDELINES

The Regional Haze Rule requires that major sources of visibility-affecting pollutants belonging to one or more of 26 specific industrial source categories evaluate BART if the source was in existence before August 7, 1977 and began operation after August 7, 1962. "Major sources of visibility-affecting pollutants" are sources that have the potential to emit 250 tons per year (tpy) or more of any of the following: oxides of nitrogen (NO_X), sulfur dioxide (SO_2), or particulate matter (PM).[1] The "BART-eligible source" is the collection of sources at a facility meeting the applicability criteria.

1.1.1 BART APPLICABILITY

In the BART applicability analysis, a BART-eligible source is determined to be subject to BART if it causes or contributes to visibility impairment at one or more of the 156 federally protected Class I areas. Per the U.S. EPA's BART Modeling Guidance, "an individual source will be considered to 'cause visibility impairment' if the emissions

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[1] As allowed in the BART Guidelines, the ADEQ has determined that volatile organic compounds (VOC) and ammonia are not visibility-affecting pollutants for the purposes of BART analyses.

results in a change (delta △) in deciviews (dv)[2] that is greater than or equal to 1.0 deciview on the visibility in a Class I area…if the emissions from a source results in a change in visibility that is greater than or equal to 0.5 dv in a Class I area the source will be considered to 'contribute to visibility impairment.'" To determine whether a BART-eligible facility causes or contributes to visibility impairment, the U.S. EPA guidance requires the use of an air quality model, specifically recommending the CALPUFF modeling system, to quantify the impacts attributable to a single BART-eligible source. Because contribution to visibility impairment is sufficient cause to require a BART determination, 0.5 dv is the critical threshold for assessment of BART applicability.

Regional haze is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index (*HI*) expressed in dv. The *HI* is calculated as shown in the following equation.

$$HI = 10 \ln\left(\frac{b_{ext}}{10}\right)$$

The impact of a BART-eligible source is determined by comparing the *HI* attributable to a source to estimated natural background conditions. That is, a single-source visibility impact is measured as the change in light extinction versus background, and is referred to as △dv. The background extinction coefficient is affected by various chemical species and the Rayleigh scattering phenomenon and can be calculated as shown in the following equation.

$$b_{ext,background}\left(\mathrm{Mm}^{-1}\right) = b_{SO_4} + b_{NO_3} + b_{OC} + b_{Soil} + b_{Coarse} + b_{EC} + b_{Ray}$$

where:

$b_{SO_4} = 3\left[(\mathrm{NH_4})_2\mathrm{SO_4}\right] f(RH)$

$b_{NO_3} = 3\left[\mathrm{NH_4NO_3}\right] f(RH)$

$b_{OC} = 4[\mathrm{OC}]$

$b_{Soil} = 1[\mathrm{Soil}]$

$b_{Coarse} = 0.6[\text{Coarse Mass}]$

$b_{EC} = 10[\mathrm{EC}]$

$b_{Ray} = \text{Rayleigh Scattering}\left(10\ \mathrm{Mm}^{-1}\ \text{by default}\right)$

$f(RH) = \text{Relative Humidity Function}$

$[\ ] = \text{Concentration in } \mu\mathrm{g/m}^3$

$\left[(\mathrm{NH_4})_2\mathrm{SO_4}\right]$ denotes the ammonium sulfate concentration

$\left[\mathrm{NH_4NO_3}\right]$ denotes the ammonium nitrate concentration

$[\mathrm{OC}]$ denotes the concentration of organic carbon

$[\mathrm{Soil}]$ denotes the concentration of fine soils

$[\text{Coarse Mass}]$ denotes the concentration of coarse dusts

$[\mathrm{EC}]$ denotes the concentration of elemental carbon

Rayleigh Scattering is scattering due to air molecules

Values for the parameters listed above specific to the natural background conditions at each Class I area are provided on an annual-average basis in the U.S. EPA's *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule*.[3]

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[2] The deciview (dv) is a metric used to represent normalized light extinction attributable to visibility-affecting pollutants.

[3] U.S. EPA, *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, Table 2-1, Attachment A, September 2003, EPA-454/B-03-005.

Particulate species that affect visibility are emitted from anthropogenic (human-caused) sources and include coarse particulate matter (PMC), fine particulate matter (PMF), and elemental carbon (EC) as well as precursors to secondary organic aerosols (SOA) and fine particulate matter such as SO_2 and NO_X. The extinction coefficient due to emissions of visibility-affecting pollutants from a single BART-eligible source is calculated according to the following equation.

$$b_{ext,source}\left(\mathrm{Mm}^{-1}\right) = b_{SO_4} + b_{NO_3} + b_{SOA} + b_{PMF} + b_{PMC} + b_{EC}$$

where:

$$\begin{aligned}
b_{SO_4} &= 3\left[(\mathrm{NH}_4)_2\mathrm{SO}_4\right]f(RH) \\
b_{NO_3} &= 3\left[\mathrm{NH}_4\mathrm{NO}_3\right]f(RH) \\
b_{SOA} &= 4[\mathrm{SOA}] \\
b_{PMF} &= 1[\mathrm{PMF}] \\
b_{PMC} &= 0.6[\mathrm{PMC}] \\
b_{EC} &= 10[\mathrm{EC}] \\
f(RH) &= \text{Relative Humidity Function} \\
[\ ] &= \text{Concentration in } \mu\mathrm{g/m}^3
\end{aligned}$$

$\left[(\mathrm{NH}_4)_2\mathrm{SO}_4\right]$ denotes the ammonium sulfate concentration
$\left[\mathrm{NH}_4\mathrm{NO}_3\right]$ denotes the ammonium nitrate concentration
$[\mathrm{SOA}]$ denotes the concentration of secondary organic aerosols
$[\mathrm{PMF}]$ denotes the concentration of fine PM
$[\mathrm{PMC}]$ denotes the concentration of coarse PM
$[\mathrm{EC}]$ denotes the concentration of elemental carbon

1.1.1.1 CALPUFF MODELING ANALYSES

As stated above, the BART Guidelines recommend using the CALPUFF modeling system to compute the 24-hour average visibility impairment attributable to a BART-eligible source to assess whether the 0.5 Δdv contribution threshold is exceeded, and if so, the frequency, duration, and magnitude of any exceedance events. CALPUFF is a refined air quality modeling system that is capable of simulating the dispersion, chemical transformation, and long-range transport of multiple visibility-affecting pollutant emissions and is therefore preferred for BART applicability and determination analyses.

1.1.2 BART DETERMINATION

BART-eligible sources that are found to cause or contribute to visibility impairment at a Class I area are required to make a BART determination. The BART Guidelines define BART as follows:

> *BART means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life*

of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. The BART analysis identifies the best system of continuous emission reduction taking into account:

1. *The available retrofit control options,*
2. *Any pollution control equipment in use at the source (which affects the availability of options and their impacts),*
3. *The costs of compliance with control options,*
4. *The remaining useful life of the facility,*
5. *The energy and non-air quality environmental impacts of control options*[*, and*]
6. *The visibility impacts analysis.*

The BART Guidelines define the following three steps for determining which emission units at a facility are BART-eligible:

1. Identify the emission units in the BART source categories,
2. Identify the start-up dates of those units, and
3. Compare potential emissions to the 250 ton/yr cutoff.

"Fossil-fuel boilers of more than 250 million BTUs per hour heat input" are one of the listed BART source categories. The Ashdown Mill's No. 1 and No. 2 Power Boilers are each greater than 250 million British thermal units per hour (MMBtu/hr), were in existence on August 7, 1977, began operation after August 7, 1962, and each have potential emissions greater than 250 tpy of PM, NO_X, or SO_2; therefore, these units make up the Ashdown Mill's BART-eligible source. A summary of the BART eligibility criteria for each emission unit is provided in Table 2-1.

TABLE 2-1. SUMMARY OF BART-ELIGIBLE EMISSION UNITS

Emission Unit	Source Number	BART Source Category	Year of Completion of Construction or Reconstruction	Potential SO_2 Emissions (tpy)	Potential NO_X Emissions (tpy)	Potential PM/PM_{10} Emissions (tpy)
No. 1 Power Boiler	SN-03	Boiler [a]	1968	214.0	1,084.1	1,502.3
No. 2 Power Boiler	SN-05	Boiler [a]	1976	4,305.5	2,514.1	359.2

[a] Fossil-fuel boilers of more than 250 million BTUs per hour heat input.

Detailed descriptions of each unit are provided in the sub-sections below.

2.1 NO. 1 POWER BOILER

The No. 1 Power Boiler (SN-03), also known as the Bark Boiler, was installed in 1968. It has a heat input rating of 580 MMBtu/hr and an average steam generation rate of approximately 120,000 pounds per hour (lb/hr). It combusts primarily bark (approximately 75 percent of the heat input is supplied by bark), but is also permitted to burn bark and wood chips used to absorb oil spills, wood waste, recycled sanitary products composed of cellulose and polypropylene, pelletized paper fuel (PPF), tire-derived fuel (TDF), municipal yard waste, No. 6 fuel oil, reprocessed fuel oil, used oil generated on site, and natural gas. Natural gas is only used to supplement other fuels during high steam demand periods. Fuel oil usage is limited to 2,700,000 gallons per year, and the sulfur content of the fuel oil used is limited to 3.0 percent by weight. TDF usage (total for No.1, No. 2, and No. 3 Power Boilers) is limited to 220 tons per day.

The No. 1 Power Boiler is equipped with a traveling grate, a combustion air system, and multiclones.

The No. 1 Power Boiler is not subject to any New Source Performance Standards (NSPS) in 40 CFR Part 60. It is subject to 40 CFR Part 63, Subpart DDDDD, *National Emissions Standard for Hazardous Air Pollutants* (NESHAP) *for Industrial, Commercial, and Institutional Boilers and Process Heaters*. NESHAP DDDDD establishes Maximum Achievable Control Technology (MACT) limits and is commonly referred to as "the Boiler MACT."

To meet the applicable Boiler MACT PM emission standard of 0.07 lb/Mmbtu, Domtar is preparing to install a wet electrostatic precipitator (WESP) on the No. 1 Power Boiler.

2.2 NO. 2 POWER BOILER

The No. 2 Power Boiler (SN-05) started operations in February 1976. It has a heat input rating of 820 MMBtu/hr and an average steam generation rate of approximately 600,000 lb/hr. It combusts primarily bituminous coal (over 80 percent of the heat input is supplied by coal), but is also permitted to burn bark, bark and wood chips used to absorb oil spills, wood waste, petroleum coke (pet coke), recycled sanitary products based on cellulose and polypropylene, PPF, TDF, municipal yard waste, No. 6 fuel oil, reprocessed fuel oil, used oil generated on site, natural gas, and non-condensable gases (NCGs). The NCGs are produced in the pulp area (from the cooking of chips) and evaporator area (where weak black liquor is concentrated) and consist of nitrogen, total reduced sulfur (TRS) compounds, methanol, acetone, SO_2, and minor quantities of other compounds such as methyl ethyl ketone (MEK). Under normal operating conditions, natural gas is not combusted.

The No. 2 Power Boiler is equipped with a traveling grate, combustion air system including overfire air, multiclones, and two parallel venturi scrubbers. The SO_2 loading to the boiler is significant since the boiler burns coal and NCGs. Therefore, the scrubbing fluid includes water and a source of alkali, such as sodium hydroxide (i.e., caustic) and/or pulp mill extraction stage filtrate.

The No. 2 Power Boiler is subject to 40 CFR 60, Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971*, 40 CFR 60, Subpart BB, *Standards of Performance for Kraft Pulp and Paper Mills* (since it combusts NCGs), and 40 CFR Part 63, Subpart DDDDD, *National Emissions Standard for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*.

The No. 2 Power Boiler is equipped with Continuous Emissions Monitoring Systems (CEMS) for NO_X, SO_2, and carbon monoxide (CO). In accordance with 40 CFR 60, Subpart BB, the No. 2 Power Boiler also has a continuous flame pyrometer to measure the temperature at the point of NCG injection (the temperature at the injection point must remain at or above 1200 ºF for at least 0.5 seconds at all times that NCGs are being burned).

3. BART APPLICABILITY ANALYSIS

This section summarizes the source-specific inputs and results of the BART applicability analysis conducted by the ADEQ for Domtar's Ashdown Mill BART-eligible source. The screening modeling methodologies and data resources used by the ADEQ in executing the CALPUFF modeling system are described in technical detail in the ADEQ's *Draft BART Modeling Protocol* (the Protocol), dated June 7, 2006, and in the Central Regional Air Planning Association (CENRAP) *BART Modeling Guidelines* (issued on December 22, 2005, and re-issued on February 3, 2006). A copy of the Protocol is included in Appendix A.

3.1 MODELED ASHDOWN MILL EMISSIONS

Whereas the BART eligibility determination relies on current potential emissions of visibility-affecting pollutants, the BART applicability modeling analysis is based on maximum 24-hour average actual emission rates of NO_X, SO_2, and PM_{10} for the modeled three-year period (i.e., 2001, 2002, & 2003).[4] At the ADEQ's request, Domtar estimated the 24-hour average maximum actual emission rates of visibility-affecting pollutants from the No. 1 and No. 2 Power Boilers using a combination of CEMS data, source-specific stack testing results, and emission factors from U.S. EPA's AP-42. These emission rates are summarized in Table 3-1.

TABLE 3-1. SUMMARY OF 24-HOUR AVERAGE MAXIMUM ACTUAL EMISSION RATES

Emission Unit	NO_X Emissions (lb/hr)	SO_2 Emissions (lb/hr)	PM_{10}/PMF Emissions (lb/hr)
No. 1 Power Boiler	179.6 [a]	6.1 [b]	169.5 [a]
No. 2 Power Boiler	412.8 [c]	557.0 [c]	62.5 [a]

[a] Based on stack testing results.
[b] Based on AP-42 data.
[c] Based on CEMS data.

3.2 MODELED ASHDOWN MILL STACK PARAMETERS

Actual stack parameters were input to the CALPUFF model to represent each emissions point. The location of each point was represented using the Lambert Conformal Coordinate (LCC) system. According to the Protocol, because the BART modeling focuses on mesoscale transport to Class I areas, effects of building downwash were not considered in the ADEQ's analysis. Table 3-2 summarizes the stack parameters modeled for the BART-eligible emission units at Domtar's Ashdown Mill.

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[4] The ADEQ assumed all PM_{10} emissions were PMF for modeling purposes.

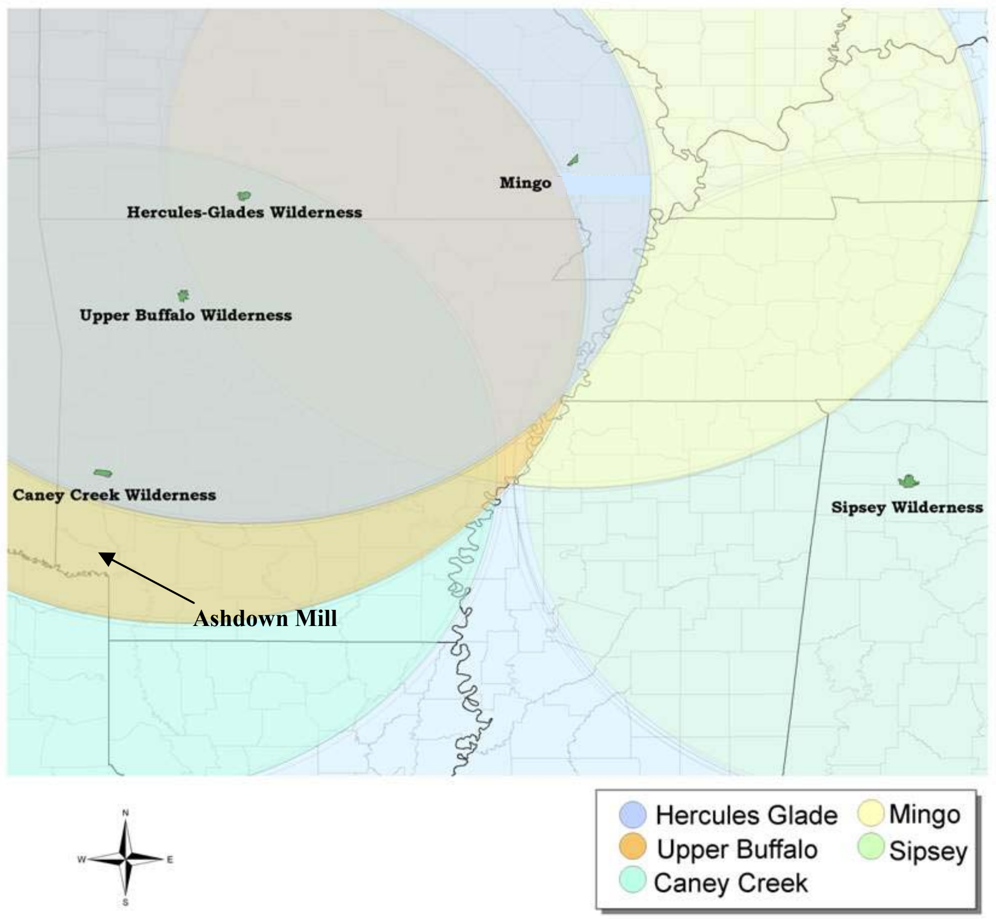
TABLE 3-2. STACK PARAMETERS

Emission Unit	LCC East (km)	LCC North (km)	Base Elevation (m)	Stack Height (m)	Stack Diameter (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)
No. 1 Power Boiler	267.47491	-698.66686	97.5	66.1	1.890	522	26.76
No. 2 Power Boiler	267.48245	-698.74355	97.5	71.6	3.659	325	11.92

3.3 POTENTIALLY AFFECTED CLASS I AREAS

Regardless of distance from the BART-eligible source, the ADEQ evaluated all Class I areas within 300 km of the Arkansas state boundary in all analyses. Figure 3-1 illustrates the location of the Ashdown Mill relative to each of the modeled Class I areas.

FIGURE 3-1. LOCATION OF ASHDOWN MILL RELATIVE TO MODELED CLASS I AREAS



Base map provided by ADEQ.

Table 3-3 presents the Class I areas (and responsible Federal Land Manager [FLM]) included in ADEQ's analyses and the approximate distance from each area to the Ashdown Mill.

TABLE 3-3. MODELED CLASS I AREAS

Class I Area	FLM [a]	Approximate Distance from Ashdown Mill (km)
Caney Creek Wilderness	FS	85
Upper Buffalo Wilderness	FS	250
Hercules-Glades Wilderness	FS	350
Mingo Refuge	FWS	510
Sipsey Wilderness	FS	620

[a] FS = Forest Service (Department of Agriculture), FWS = Fish and Wildlife Service (Department of Interior).

3.4 BART APPLICABILITY ANALYSIS RESULTS

The ADEQ's BART applicability analysis showed that Domtar's Ashdown Mill contributes to visibility impairment, since the maximum modeled 24-hour average impacts were greater than 0.5 Δdv, in the Caney Creek, Upper Buffalo, and Mingo Class I areas. The results of the ADEQ's BART applicability analysis for Domtar's Ashdown Mill are summarized in Table 3-4.

TABLE 3-4. SUMMARY OF BART APPLICABILITY ANALYSIS RESULTS

Class I Area	Maximum 24-hour Impact (Δdv) [a]	Number of Days > 0.5 Δdv [a]	Number of Days > 1.0 Δdv [a]
Caney Creek	1.668	98	26
Upper Buffalo	0.795	6	0
Hercules-Glades	0.437	0	0
Mingo	0.570	1	0
Sipsey	0.197	0	0

[a] For total modeled period: years 2001, 2002, and 2003.

Since the ADEQ's BART applicability analysis shows that Domtar's Ashdown Mill BART-eligible source contributes to visibility impairment in at least one Class I area, Domtar must conduct a BART determination analysis for the No. 1 and No. 2 Power Boilers.

4. BART DETERMINATION ANALYSIS

In general, BART is determined for each eligible emissions unit using the following five (5) steps from Section IV.D of the BART Guidelines:

Step 1 – Identify all available retrofit control technologies,
Step 2 – Eliminate technically infeasible options,
Step 3 – Evaluate control effectiveness of remaining control technologies,
Step 4 – Evaluate impacts and document the results, and
Step 5 – Evaluate visibility impacts.

However, in the preamble to the BART Guidelines, the U.S. EPA clearly encourages the use of streamlined approaches for BART determinations so that states and industry can focus their resources on the main contributors to visibility impairment.[5] Domtar asserts that streamlined BART determinations are appropriate for emissions of PM and SO_2 from the Ashdown Mill's No. 1 and No. 2 Power Boilers. The streamlined BART determinations for PM and SO_2 are presented in Sections 4.1, 4.2, and 4.3. Steps 1 through 4 of the BART determination analysis for NO_X emissions from the No. 1 and No. 2 Power Boilers are presented in Section 4.3. Section 4.5 presents the visibility impacts evaluation for all pollutants.

4.1 BART DETERMINATION FOR PM

Section IV.C of the BART Guidelines describes a streamlined approach for evaluating BART for certain sources that are subject to MACT standards (i.e., NESHAP in 40 CFR 63). The Ashdown Mill's No. 1 and No. 2 Power Boilers are affected sources (in the existing, large, solid fuel subcategory) under the Boiler MACT, and are subject to a PM emissions standard of 0.07 lb/MMBtu. Since the Boiler MACT standard was established recently the technology analysis is up-to-date. The No. 1 and No. 2 Power Boilers must be in compliance with the Boiler MACT standards by September 13, 2007, in advance of the anticipated 2013 BART compliance deadline. The No. 2 Power Boiler is equipped with a wet scrubber and can meet the Boiler MACT PM emission standard. Domtar is planning to equip the No. 1 Power Boiler with a WESP to meet the PM standard. Table 4-1 presents the maximum PM emission rates from each power boiler based on heat input capacity and the Boiler MACT standard.

TABLE 4-1. BART / BOILER MACT-BASED PM EMISSION RATES

Emission Unit	PM Emissions (lb/hr)	PM Emissions (tpy)
No. 1 (Bark) Power Boiler	40.6	177.9
No. 2 (Coal) Power Boiler	57.4	251.5

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[5] Federal Register, Vol. 70, No. 128, July 6, 2005, pp 39107 and 39116.

The recent Boiler MACT PM emission standard is presumptively relied upon to meet BART requirements. Accordingly, a comprehensive BART determination analysis is not necessary to determine BART for PM emissions from the Ashdown Mill's No. 1 and No. 2 Power Boilers. The ADEQ agreed to allow this streamlined MACT-equals-BART option in a September 8, 2006, letter, but required that Domtar "consult with the ADEQ Air Division regarding whether the wet electrostatic precipitator (MACT Control) is the best available and cost effective control technology for $PM_{2.5}$."[6] Domtar provides the following evidence that a WESP is the best choice for control of the No. 1 Power Bark Boiler.

Particulate emissions from wood-fired boilers are typically controlled by one of four technologies: baghouse (fabric filter), ESP (wet or dry), wet scrubber, or cyclone. Cyclones provide for the lowest control efficiencies of the options at up to 65 percent, and particulate collection efficiencies of 85 percent or greater have been reported for venturi [wet] scrubbers operating on wood-fired boilers.[7] To achieve control efficiencies of 90 percent or greater, a baghouse or ESP is used. The normal PM control efficiency range for a fabric filter is 95 to 99+ percent, and the normal PM control efficiency range for a WESP is 98 to 99+ percent.[8] Fabric filters are rarely used on wood-fired boilers due to concerns about bag flammability.[9] The principal drawback is a fire danger arising from the collection of combustible carbonaceous fly ash.[10] Both types (i.e., wet and dry) of ESPs are capable of greater than 99 percent removal of particle sizes above 1 micron.[11] An additional benefit of WESPs is that the wash used in WESPs can also have some control effect on other pollutant gases via absorption and can help condense other emissions due to the cooling of the stream.[12] Based on the comparison of control efficiencies and the applicability of each control device, Domtar asserts that the WESP is the best control technology (i.e., BART) for the No. 1 Power Boiler.

4.2 BART DETERMINATION FOR SO_2 – NO. 1 POWER BOILER

Generally, pre-combustion SO_2 control strategies involve fuel switching/blending or fuel cleaning so that less fuel-bound sulfur enters the process. However, because wood already contains very little sulfur, pre-combustion SO_2 controls are ineffective.

Post-combustion SO_2 control is accomplished by reacting the SO_2 in the gas with a reagent (usually calcium-based [e.g., lime or limestone] or sodium-based [e.g., caustic]) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use. SO_2 reduction technologies are commonly referred to as flue gas desulfurization (FGD) and/or scrubbers and are usually described in terms of the process conditions (wet versus dry), byproduct utilization (throwaway versus saleable) and

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[6] Mike Bates (ADEQ), letter to Kelley Crouch (Domtar), September 8, 2006.

[7] U.S. EPA, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Source* (AP-42), Fifth Edition, Section 1.6 – Wood Residue Combustion in Boilers, September 2003.

[8] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

[9] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

[10] U.S. EPA, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Source* (AP-42), Fifth Edition, Section 1.6 – Wood Residue Combustion in Boilers, September 2003.

[11] Northeast States for Coordinated Air Use Management (NESCAUM) and Mid-Atlantic/Northeast Visibility Union (MANE-VU), *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

[12] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

reagent utilization (once-through versus regenerable).[13] Post-combustion SO_2 controls have not been installed on wood-fired boilers because of the relatively low SO_2 emissions from wood-combustion (due to the low sulfur content of wood).

Due to the low fuel sulfur input, emissions from wood-fired boilers, specifically the Ashdown Mill's No. 1 Power Boiler, are inherently low, in fact well below the permitted limit, and have a negligible impact on visibility impairment. To illustrate this point, Domtar revised the ADEQ's BART applicability modeling for the Ashdown Mill (see Section 3) to consider only SO_2 emissions from the No. 1 Power Boiler. The results of this modeling show that SO_2 emissions from the Ashdown Mill's No. 1 Power Boiler contribute a maximum of only 0.008 Δdv at any Class I area (see Table 4-8 for each Class I area's impact). Thus, even 100 percent control of SO_2 emissions would not provide significant improvement of visibility impairment. Therefore, Domtar proposes "no additional control" and the current permit limit (214.0 tpy) as BART for SO_2 emissions from the No. 1 Power Boiler.

4.3 BART DETERMINATION FOR SO_2 – NO. 2 POWER BOILER

Section IV.D.1.9 of the BART Guidelines provides an option to skip the comprehensive BART determination analysis for BART-eligible emission units that are already equipped with the most stringent controls available (including any possible improvements to the control device) "as long these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source." The Ashdown Mill's No. 2 Power Boiler is equipped with a wet scrubber for control of SO_2 (and particulate) emissions. The existing wet scrubber achieves an SO_2 control efficiency of approximately 90 percent, which is within the normal range for the highest efficiency SO_2 control strategies and is the BART-based control efficiency presumed by the Central Regional Air Planning Association (CENRAP) and the Midwest Regional Planning Organization (MRPO) for pulp and paper industry power boilers.[14,15]

The No. 2 Power Boiler is equipped with a CEMS for SO_2. Thus, Domtar is able to immediately identify needs for both ongoing operational adjustments and periodic maintenance and/or scrubber improvements to maintain high levels of SO_2 control. It should be noted that the No. 2 Power Boiler is operated such that SO_2 emissions are well below any applicable limits/standards. Since wet scrubbing is the most effective method of controlling SO_2 emissions, no additional analysis is needed for SO_2 emissions from the No. 2 Power Boiler. Domtar proposes a BART limit equal to the current SO_2 permit limit (4,305.5 tpy) for the No. 2 Power Boiler.

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[13] NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

[14] CENRAP's Control Estimates Spreadsheet dated January 10, 2006.

[15] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.

4.4 BART DETERMINATION ANALYSIS FOR NO_X

Each required step of the BART determination analysis for emissions of NO_X from the No. 1 and No. 2 Power Boilers is presented below.

4.4.1 STEP 1 - IDENTIFY ALL AVAILABLE RETROFIT CONTROL TECHNOLOGIES

The BART Guidelines require the consideration of all "control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation." The list of available control options should include "the most stringent option and a reasonable set of options for analysis…[, but] it is not necessary to list all permutations of available control levels that exist for a given technology – the list is complete if it includes the maximum level of control each technology is capable of achieving."

Per the BART Guidelines, the BART determination analysis must "take into account technology transfer of controls that have been applied to similar source categories and gas streams [in addition to] existing controls for the source category in question." However, "technologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; [the U.S. EPA does] not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice." The BART Guidelines provides the following additional considerations for preparing the list of potential control options:

- One of the control options should reflect the level of control equivalent to any applicable NSPS,
- Source redesign should not be considered,
- Fuel switching should not be considered, and
- For emission units with existing control measures or devices, one of the control options should involve improvements to the existing controls.

Potential NO_X control technologies and resulting emission control quantities for the Ashdown Mill's No. 1 and No. 2 Power Boilers were identified from the exhaustive review of the U.S. EPA's Clean Air Technology Center, including the RACT/BACT/LAER Clearinghouse (RBLC), control equipment vendor information, publicly-available air permits and applications, and technical literature published by the U.S. EPA, the Regional Planning Organizations (RPOs), and industry groups such as the National Council for Air and Stream Improvement, Inc. (NCASI).[16] In fact, Domtar has largely relied upon the extensive research conducted by NCASI regarding the applicability and effectiveness of each control option for coal- and wood-fired pulp and paper mill power boilers. Each NO_X

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[16] *NCASI is an independent, non-profit research institute that focuses on environmental topics of interest to the forest products industry. NCASI was established in 1943…In the years since, NCASI has developed technical expertise spanning the spectrum of environmental challenges facing the forest products industry, and is today recognized as the leading source of reliable data on environmental issues affecting this industry.* (http://www.ncasi.org/about/default.aspx)

control option identified as potentially applicable to either power boiler is listed below and explained in detail in the following subsections.

- Selective Non-Catalytic Reduction (SNCR) / NO_XOUT
- Selective Catalytic Reduction (SCR)
- Low NO_X Burners (LNB) and Ultra Low NO_X Burners (ULNB)
- Over-fire Air (OFA)
- Reburning / Methane de-NO_X (MdN)
- Flue Gas Recirculation (FGR) (Internal and External)
- Fuel Blending / Boiler Operational Modifications / Tuning / Optimization

For this analysis, utility boiler control technology determinations were generally not considered since utility boilers and pulp and paper mill power boilers are considered too dissimilar.

> *The greatest difference in utility and power boiler operations is the fluctuating steam demand characteristic of pulp and paper mill operations which requires that power boilers continuously adjust fuel firing rates and excess air levels. Even with the most sophisticated combustion controls, it is not practical or safe to maintain excess air continuously at minimum levels. Consequently, power boilers have characteristically and inherently higher NO_X emissions.*
>
> *…NO_X reduction measures are particularly difficult to implement in small, low capacity facilities because a) residence time is limited and often inadequate for applying OFA without excessive loss of thermal efficiency or induced smoking; b) relatively small furnace dimensions limit combustion modifications that increase flame length and tend to cause the flame to impinge on tube wall;, c) peak boiler efficiency and minimized NO_X emissions occur close to minimum flue-gas O_2 content, which is at the threshold of smoke or combustible-emissions formation; d) steam is used far more effectively in industrial applications than in conventional electric utility plants and, consequently, emission limits based on boiler heat input or volume of flue gas do not recognize such efficiency.*[17]

Combustion-related NO_X emissions are formed by two mechanisms. NO_X formed from oxidation of molecular nitrogen (N_2) in combustion air is referred to as "thermal NO_X" and is dependent on high temperatures (approximately 2,800 °F) and an excess of combustion air. NO_X formed by oxidation of nitrogen compounds in fuel is referred to as "fuel NO_X." The NO_X formed from coal combustion is primarily fuel NO_X.[18] Fuel NO_X is also the dominant NO_X formation mechanism operative during wood combustion because wood combustion in boilers seldom reaches high enough temperatures.[19,20]

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[17] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[18] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

[19] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

The possible NO_X emissions control technologies generally fit into one of two categories: combustion modifications, which are often associated with improving boiler performance, or flue gas treatment (i.e., post-combustion controls). Pre-combustion techniques to reduce fuel NO_X have shown little promise.[21] Combustion modifications are the most common, commercially available means of controlling NO_X emissions from fossil fuel-fired boilers.[22] However, since wood-fired boilers normally burn at lower temperatures (around 1,500 °F), the units have inherently lower NO_X emissions, and, as a result, NO_X combustion control technologies are not applicable to wood-fired boilers.[23] During the past decade, LNB with FGR and LNB alone were the most commonly recommended NO_X control technologies for oil/gas and coal-fired boilers, respectively, while good combustion control was typically the only recommendation for wood waste-fired boilers.[24]

COMBUSTION MODIFICATIONS

4.4.1.1 FLUE GAS RECIRCULATION

Generally, FGR involves extracting a portion (15 to 30 percent) of the flue gas and readmitting it to the furnace through the burner window. When the flue gas is extracted from the economizer or air heater outlet, a separate fan/blower is needed to withdraw the flue gas. This setup is referred to as external or forced FGR. Internal or induced FGR refers to the setup where the flue gas is extracted from upstream of the stack using the forced draft (FD) fan instead of a separate FGR fan. In either setup, the recirculated flue gas acts as a thermal diluent (i.e., heat sink) to reduce combustion temperatures. It also dilutes the combustion reactants and reduces the excess air requirements thereby reducing the concentration of oxygen in the combustion zone. Thus, thermal NO_X formation is inhibited.[25] The onset of thermal NO_X occurs around 2,800 °F, and NO_X generation increases exponentially with temperatures beyond 2,800 °F. As only thermal NO_X can be controlled by this technique, it is especially effective only in oil and gas-fired units.[26]

4.4.1.2 LOW NO_X BURNERS / ULTRA LOW NO_X BURNERS

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, flame temperature, and/or residence time. A

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[20] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[21] Ibid.

[22] Ibid.

[23] STAPPA and ALAPCO, *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, March 2006.

[24] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[25] U.S. EPA, Clean Air Technology Center, *Nitrogen Oxides (NO_X), Why and How They Are Controlled.* Research Triangle Park, North Carolina, EPA-456/F-99-006R, November 1999.

[26] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

LNB is a staged combustion process that is designed to split fuel combustion into two zones, primary combustion and secondary combustion. Two general types of LNB exist: staged fuel and staged air. Lower emission rates can be achieved with a staged fuel burner than with a staged air burner. Staged fuel LNB separate the combustion zone into two regions. The first region is a lean primary combustion region where the total quantity of combustion air is supplied with a fraction of the fuel. Combustion in the primary region (first stage) takes place in the presence of a large excess of oxygen at substantially lower temperatures than a standard burner. In the second region, the remaining fuel is injected and combusted with any oxygen left over from the primary region. The remaining fuel is introduced in the second stage outside of the primary combustion zone so that the fuel/oxygen are mixed diffusively (rather than turbulently), which maximizes the reducing conditions. This technique inhibits the formation of thermal NO_X, but has little effect on fuel NO_X. By increasing residence times staged air LNB provide reducing conditions, which have a greater impact on fuel NO_X than staged fuel burners. The estimated NO_X control efficiency for LNB in high temperature applications is 25 percent.[27]

The application of LNB is often limited by the longer flames produced as a consequence of improved air distribution control. While there is generally ample room for LNB flames in utility furnaces, their use on smaller power boilers can result in flame impingement on furnace walls, leading to tube wall overheating and mechanical failure. Flame impingement can also result in premature flame quenching and increased soot and CO emissions.[28]

ULNB combine LNB and FGR technologies and may incorporate other techniques such steam injection. The FGR design within ULNB recirculates flue gas from the flame or firebox back into the combustion zone in an effort to reduce oxygen concentrations without significantly reducing flame temperature. Reduced oxygen concentrations in the flame have a strong impact on fuel NO_X.[29] ULNB also tend to have large diameters, but shorter flame lengths and may be easier to retrofit.[30]

Combustion modification with LNB is used in both gas/oil-fired and coal-fired units.[31] LNB are not used for wood-fired boilers. The No. 1 Power Boiler burns only a small amount of fuel for which LNB technology exists. Therefore, LNB is not considered further for the No. 1 Power Boiler.

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[27] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

[28] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[29] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

[30] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[31] Ibid.

4.4.1.3 OVERFIRE AIR

In OFA, about 10 to 20 percent of the combustion air flow is directed to separate air ports located downstream of the burners. OFA works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect and theoretically reducing NO_X emissions. Residual unburned material, such as CO and unburned carbon, which inevitably escapes the main burner zone, is oxidized as the OFA is admixed later.[32]

OFA vendors (e.g., Jansen Combustion and Boiler Technologies, Inc.) have informed Domtar that while OFA often results in decreased NO_X emissions, the primary purpose is combustion optimization, and implementation of OFA can actually increase NO_X emissions in certain circumstances. Domtar has experienced this potential adverse effect. A recent OFA upgrade to the Ashdown Mill's No. 3 Power Boiler (not a BART-eligible unit) is still in startup mode, but so far Domtar has measured a noteworthy increase in NO_X emissions.

The Ashdown Mill's No. 1 and No. 2 Power Boilers are already equipped with OFA systems that were part of the original boiler designs. These systems were not necessarily designed for NO_X reduction. The No. 2 Power Boiler is also equipped with an additional "NO_X air" system, which could be considered a type of OFA, but it located higher in the furnace than typical OFA systems. As required by the BART Guidelines, upgrades/improvements to the existing OFA systems are considered further in this analysis.

4.4.1.4 REBURNING / METHANE DE-NO_X

In reburning, also known as "off-stoichiometric combustion" or "fuel staging," a fraction (5 to 25 percent) of the total fuel heat input is diverted to a second combustion zone downstream of the primary zone. The fuel in the fuel-rich secondary zone acts as a reducing agent, reducing NO, which is formed in the primary zone, to N_2. Low nitrogen-containing fuels such as natural gas and distillate oil are typically used for reburning to minimize further NO_X formation. Generally, it is more economical for a facility to use the same fuel for reburning as it does for primary combustion, although there are exceptions. In order to use coal as a reburning fuel, it must be finely ground, which requires additional pulverizing equipment.[33]

MdN utilizes the injection of natural gas together with recirculated flue gases (for enhanced mixing) to create an oxygen-rich zone above the combustion grate. OFA is then injected at a higher furnace elevation to burn out the combustibles. This process is claimed to yield between 50 and 70 percent NO_X

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[32] Ibid.

[33] STAPPA and ALAPCO, *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, March 2006.

reduction and to be suitable for all solid fuel-fired stoker boilers. However, as of 2002, MdN had only been demonstrated for a short duration in one pulp mill wood-fired stoker boiler that also burned small amounts of waste treatment plant residuals, with NO_X reductions of 40 to 50 percent reported.[34]

More recently, MdN is being applied to kraft pulp mill stoker boilers by utilizing the VOC content of NCGs to partially replace the natural gas (by up to 25 percent). This technology has been tested for over a year at one pulp mill boiler, and is being tested at several boilers within one forest products industry (FPI) company.[35]

4.4.1.5 FUEL BLENDING

Since wood is inherently low in nitrogen content, fuel blending is not feasible for wood-fired boilers. Therefore, this control strategy is not considered for the Ashdown Mill's No. 1 Power Boiler.

Coal-fired boilers could experience a decrease in NO_X emissions from fuel blending. Preliminary results show that the co-firing of up to 7 percent biomass, on a heat-input basis, with crushed or pulverized coal can lower NO_X emissions by as much as 15 percent.[36] However, fuel biasing on an industrial boiler subject to rapid and excessive load swings could result in too rich or too lean firing conditions, which can lead to flame stability problems and explosive conditions.[37] In addition, unlike utilities, which can specify the nitrogen content of their large oil purchases, most industrial mills cannot.[38]

Domtar historically mixes 10 to 15 percent (heat input basis) wood with coal in the No. 2 Power Boiler. Therefore, fuel blending is considered part of the base case for the No. 2 Power Boiler.

4.4.1.6 BOILER OPERATIONAL MODIFICATIONS / TUNING / OPTIMIZATION

Combustion optimization efforts can lead to improvements in NO_X emissions of 5 to 15 percent. Recent developments of intelligent controls – software-based systems that "learn" to operate a unit and then maintain its performance during normal operation – are expected help in keeping plants well tuned.[39] Domtar has employed, and will continue to employ, the latest boiler optimization and tuning techniques. This control strategy is considered part of the base case for the Ashdown Mill's No. 1 and No. 2 Power Boilers.

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[34] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[35] Ibid.

[36] Ibid.

[37] Ibid.

[38] Ibid.

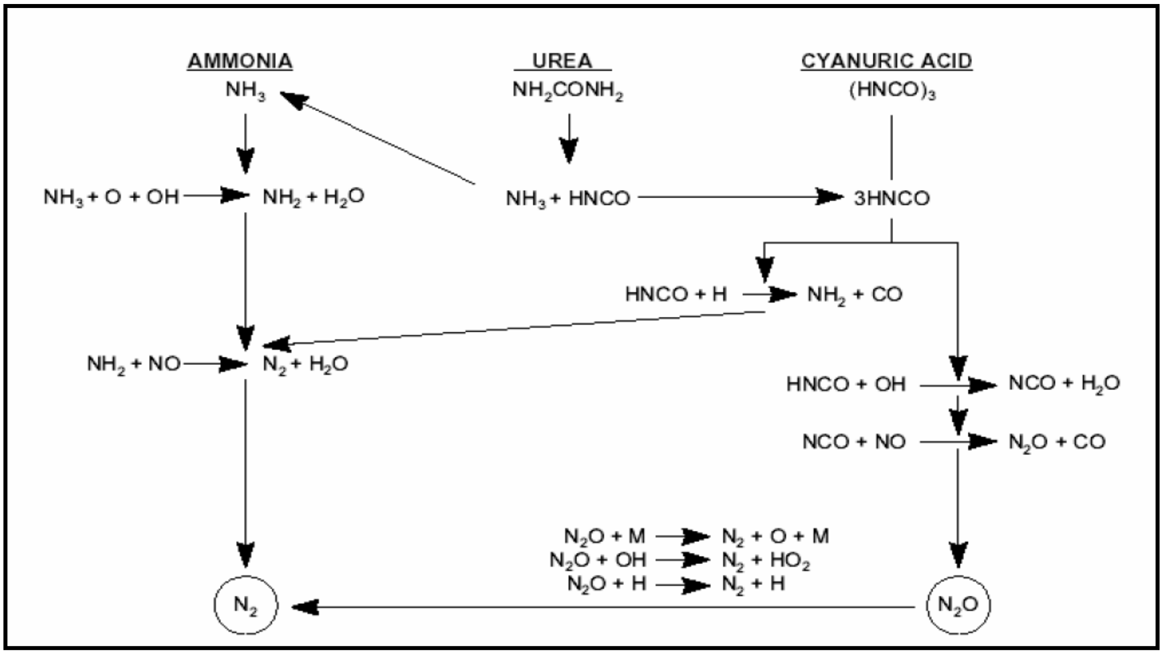
[39] NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

POST-COMBUSTION CONTROLS

4.4.1.7 SELECTIVE NON-CATALYTIC REDUCTION

SNCR is a post-combustion NO_X control technology based on the reaction of urea or ammonia (NH_3) and NO_X. In the SNCR chemical reaction, urea or ammonia-based chemicals are injected into the combustion gas path to reduce the NO_X to nitrogen and water. The primary SNCR reaction sequences are shown in Figure 4-1.[40]

FIGURE 4-1. PRIMARY SNCR REACTION SEQUENCES



Typical NO_X removal efficiency for SNCR is 30 to 65 percent. For industrial coal-fired boilers, SNCR can achieve approximately 40 percent NO_X control.[41] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000 °F.[42] Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NO_X. In addition, the urea must have sufficient residence time, about 3 to 5 seconds, at the optimum operating temperatures for efficient NO_X reduction. Therefore, the injection point is typically prior to convective heat recovery.[43]

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[40] ABB Power Plant Laboratories, *Engineering development of coal-fired high performance power systems – Phase II topical report*, Selective Non-Catalytic Reduction System Development Subcontract to United Technologies Research Center, Contract No. DE-AC22-95PC95144, February 24, 1997 (reprinted in NCASI's Special Report No. 03-04).

[41] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.

[42] U.S. EPA, Clean Air Technology Center, *Nitrogen Oxides (NO_X), Why and How They Are Controlled*. Research Triangle Park, North Carolina, EPA-456/F-99-006R, November 1999.

[43] U.S. EPA. *Summary of NO_X Control Technologies and their Availability and Extent of Application*. Research Triangle Park, North Carolina. EPA-450/3-92-004, February 1992.

According to the U.S. EPA, the performance of an SNCR system is affected by six factors.

> *These are a) inlet NO_X level, b) temperature, c) mixing, d) residence time, e) reagent-to- NO_X ratio, and f) fuel sulfur content. Lower inlet NO_X concentrations reduce the reaction kinetics and hence the achievable NO_X emissions reductions. As mentioned above, temperatures below the desired window result in ammonia emissions (slip), and temperatures above the desired window result in NH_3 being oxidized to NO_X. Mixing becomes an important consideration in regions distant from an injection nozzle where the level of turbulence is reduced and stratification of the reagent and flue gas will probably be a greater problem, especially at low boiler loads. Residence time becomes important to allow the desired reactions to go to completion. Small, packaged, water tube boilers and boilers with varying steam loads are therefore difficult applications for SNCR. As higher than the theoretical NH_3 to NO_X ratios are generally required to achieve desired NO_X emission reductions, a trade-off exists between NO_X control and the presence of NH_3 in the flue gas. The main disadvantage of SNCR is the low NO_X reduction that is experienced when the allowable ammonia slip is low. Finally, in the case of high sulfur fuels, excess NH_3 can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit on downstream equipment leading to plugging and reduced heat transfer efficiencies.*[44]

One concern about the SNCR process is its ability to perform adequately under changing load and fuel conditions.[45] Based on its research regarding this concern, NCASI concludes that SNCR is most widely used for base-loaded boilers, and is not suited for power boilers that experience wide temperature variances, i.e., high load swings. NCASI also points out that the use of SNCR systems on coal-fired boilers is still in the development stage.[46]

The NO_XOUT process is an SNCR hybrid based on the following chemical reaction that ideally occurs in the temperature range of 1700 to 2000 °F:

$$2\ NO + NH_2CONH_2 + 1/2\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$

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[44] U.S. EPA, *New source performance standards, subpart Db – technical support for proposed revisions to NO_X*, EPA-453-/R-95-012 (republished in NCASI's Special Report 03-04).

[45] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[46] Ibid.

The problems with typical SNCR systems (e.g., ammonia slippage and heat transfer surface fouling with byproduct formation) also exist with the NO_XOUT process.

4.4.1.8 SELECTIVE CATALYTIC REDUCTION

SCR is a post-combustion gas treatment process in which NH_3 is injected into the exhaust gas in the presence of a catalyst bed usually located between the boiler and air preheater. The catalyst lowers the activation energy required for NO_X decomposition.[47] On the catalyst surface, NH_3 and nitric oxide (NO) react to form diatomic nitrogen and water. The overall chemical reaction can be expressed as:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

When operated within the optimum temperature range of approximately 575 to 750 °F, the reaction can result in removal efficiencies between 70 and 90 percent. For coal-fired industrial boilers, SCR can achieve approximately 80 percent NO_X control.[48] The specific temperature ranges are 600 to 750 °F for conventional (vanadium or titanium) catalysts, 470 to 510 °F for platinum catalysts, and 600 to 1000 °F for high-temperature zeolite catalysts.[49] SCR units have the ability to function effectively under fluctuating temperature conditions (usually ± 50 °F), although fluctuation in exhaust gas temperature reduces removal efficiency by disturbing the chemical kinetics (speed) of the NO_X -removal reaction.

According to the U.S. EPA, the performance of an SCR system is affected by six factors.

> *These are a) NO_X level at SCR inlet, b) flue gas temperature, c) NH_3-to-NO_x ratio, d) fuel sulfur content, e) gas flow rate, and f) catalyst condition. For SCR, when inlet NO_X concentrations fall below 150 ppm, the reduction efficiencies decrease with decreasing NO_X concentrations. Each type of catalyst has an optimum operating temperature range. Temperatures below this range result in ammonia emissions (slip), and temperatures above the desired range result in NH_3 being oxidized to NO_X. For up to about 80 percent NO_X reduction efficiencies, a 1:1 NH_3:NO_X ratio is sufficient. For higher efficiencies, higher reagent to NO_X ratios are required which may result in higher NH_3 slip. In the case of high sulfur fuels, excess NH_3 can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit and foul downstream equipment. SCR application experience in the case of*

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[47] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.
[48] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.
[49] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

> *medium-to-high sulfur fuels is limited. For a given flue gas flow rate, the catalyst structural design should be chosen so that the residence time needed for the reduction reactions to take place on the catalyst surface is achievable.*[50]

4.4.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Per the BART Guidelines, documentation of infeasibility should "explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option under review." The BART Guidelines use the two key concepts of "availability" and "applicability" to determine if a control option is technically feasible. These concepts are defined in Section IV.D.2:

> *…a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.*
>
> *The typical stages for bringing a control technology concept to reality as a commercial product are:*
>
> - *concept stage;*
> - *research and patenting;*
> - *bench scale or laboratory testing;*
> - *pilot scale testing;*
> - *licensing and commercial demonstration; and*
> - *commercial sales.*
>
> *A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review.*
>
> *In general, a commercially available control option will be presumed applicable if it has been used on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously.*

COMBUSTION MODIFICATIONS

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[50] U.S. EPA, *New source performance standards, subpart Db – technical support for proposed revisions to NO_X*, EPA-453-/R-95-012 (republished in NCASI's Special Report 03-04).

4.4.2.1 FLUE GAS RECIRCULATION

FGR is used to reduce thermal NO_X formation. Emissions due to fuel-bound NO_X, which are significant for coal-fired boilers, are not meaningfully affected by FGR. Therefore, FGR is not technically feasible to control NO_X emissions from coal-fired boilers.[51] Similarly, FGR would not be effective in wood combustion since most of the NO_X generated during wood combustion is also from the fuel NO_X pathway.[52] Recent refusals by vendors (e.g., Entropy Technology & Environmental Consultants LP[53]) to provide budgetary estimates for installing FGR are further evidence that FGR is not applicable for the Ashdown Mill's No. 1 and No. 2 Power Boilers.

4.4.2.2 REBURNING / METHANE DE-NO_X

Generally, Domtar considers MdN not feasible because (1) it is not fully demonstrated and (2) it incorporates FGR, which is clearly technically infeasible (see Section 4.4.2.1). However, Domtar was able to obtain equipment cost estimates from vendors of MdN. Therefore, MdN is considered further in this analysis.

POST-COMBUSTION MODIFICATIONS

NCASI points out the following issues of concern for post-combustion NO_X controls (i.e., SNCR and SCR) for pulp and paper mill power boilers:[54]

> **Load Swings** - Pulp mill combination and power boilers frequently exhibit wide and rapid load swings that are not consistent with the steady conditions required for effective use of either SNCR or SCR NO_X control technologies. The load swings produce variable temperature conditions in the boiler, causing the temperature zone for NO_X reduction to fluctuate, making it more difficult to know where to inject the reactants.
>
> **Temperature Incompatibility** - Combination and power boilers are affected by temperature profile incompatibility. To obtain the required temperature window, the only location to install this technology is upstream of the particulate matter control device, yet this is where flue gases are dirty and can foul the catalyst rapidly.

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[51] U.S. EPA. *Alternative Control Technologies Document: NO_X Emissions from Utility Boilers.* (EPA-453/R-94-023).

[52] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[53] Steve Wood (ETEC), e-mail to Joel Martin (Domtar), September 20, 2006: "Based on the design and operational data provided regarding #2 Coal Boiler, ETEC would decline to bid the application Induced Flue Gas Recirculation for Boiler #2 NO_X control. Flue gas recirculation technology is very effective in reducing natural gas and light oil fuel NO_X emissions, but is not for No.6 fuel oil, coal, bark and other solid fuels. To the best of our knowledge, flue gas recirculation for NO_X control has never been installed on a coal fired boiler."

[54] Ibid.

> Downstream of the PM control device, the temperature is too low for the catalyst to be effective.
>
> **Unproven** – SCR or SNCR controls, technologies which, for the most part, are untested and infeasible for pulp and paper mill boilers. These technologies must be operated on a continuous basis within a specified temperature range in order to be effective. The type of fuel burned influences the design of the technology, and FPI facilities' frequent fuel changes and co-firing of multiple fuels would result in design and operational problems.
>
> **Lack of Guarantee for FPI Boilers** – Boiler owners are finding that vendors of SCR and SNCR technologies are unwilling to provide performance guarantees that the controls will meet the level of reduction called for in [NSPS Subpart Db (promulgated on September 16, 1998)].

4.4.2.3 SELECTIVE NON-CATALYTIC REDUCTION

Most boilers in the pulp and paper industry operate in the swing load mode, a consequence of supplying steam as required to the various components of the process. The problem with control of the required flue gas temperature window is an inherent difficulty with use of SNCR for load-following boilers, whether wood or fossil fuel.[55]

Controlling flue gas temperatures over the entire range of operating loads that the boiler is expected to experience will be very difficult to achieve. Boilers in the pulp and paper industry rarely operate under base loaded conditions. Consequently, the location of the desired temperature window is expected to change constantly. Accurate, instantaneous temperature measurement, as well as the ability to accurately adjust the location of the injection nozzle, would be necessary. Ammonia slip would be a recurring problem associated with the application of the SNCR process to industrial boilers with fluctuating loads.[56]

Inadequate reagent dispersion in the region of reagent injection in wood-fired boilers is also a factor mitigating against the use of SNCR technology.[57] Good dispersion of the reagent in the flue gas is needed to get good utilization of the reagent and to avoid excessive ammonia slip from the process. The need for a

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[55] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

[56] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[57] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

sufficient volume in the boiler at the right temperature window precludes the application of SNCR in all types of industrial boilers.[58]

Additional issues with SNCR include the potential for formation of ammonium sulfate salts (if sulfur oxides are present in the gas stream where they can react with excess ammonia from the SNCR process to form ammonium salts), which cause plugging problems. Ammonia also poses potential water quality issues - ammonia slip released to the atmosphere could contaminate surface waters by deposition.

SNCR has been applied to a few base-loaded wood and combination wood-fired boilers, mainly in the electric generating industry. However, its efficacy on wood-fired boilers with changing loads has not been demonstrated, except when used as a polishing step. Early use of ammonia injection in the case of one pulp mill wood-fired boiler met with significant problems and had to be abandoned (significant ammonia slip, caused by inefficient dispersion of the reagent within the boiler, was to blame). The boiler was unable to meet the manufacturer guarantee unless operated at less than half load. Even then, reducing NO_X to near permitted limits consumed considerably more ammonia than anticipated, leading to the formation of a visible ammonium chloride plume. A similar problem was encountered at a second FPI mill where nearly half the urea (on a molar basis) injected was being emitted as ammonia.[59]

The use of SNCR on stoker type wood-fired boilers that have significant load swings has not been demonstrated. Excessive ammonia slip is a primary concern when adequate dispersion of the SNCR chemical is not achieved in the boiler ductwork within the range of residence times available and temperatures needed for the NO_X reduction reactions to go to completion. Additional concerns include the impact of interference from higher CO levels present in many wood-fired boilers, the possibility of appreciable SNCR chemical being absorbed onto the ash matrix in a wood-fired boiler, and the extent and fate of ammonia in scrubber purge streams.[60]

The MRPO concludes, "if combustion zone temperatures within the boiler do not fall into [the ideal temperature range], then SNCR would be infeasible."[61]

4.4.2.4 SELECTIVE CATALYTIC REDUCTION

The use of SCR on boilers operating in the FPI has also never been successfully demonstrated for wood boilers, and would face the same inherent problem of requiring it to be post PM-control to protect the catalyst, and

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[58] NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

[59] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[60] Ibid.

[61] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

achieving and maintaining the required temperature window for effective NO_X control.[62] There are numerous other issues with using SCR including catalyst plugging and soluble alkali poisoning as well as increased energy consumption.[63]

The use of SCR technology would be considered technically infeasible based upon the fact that post-particulate removal flue gas temperatures are typically significantly lower than those desired for this application. Many boilers are equipped with wet scrubbers for particulate emission (PM) control. Reheating the scrubbed flue gases from these boilers to bring them within the desired temperature window would involve a significant energy penalty. For pre-particulate removal flue gas application, catalyst deactivation from high particulate loading would be a serious concern, in addition to the impact of fluctuating loads on flue gas temperatures. Deactivation and/or poisoning could result from the size and density of fly ash particulate, and from their unique chemical and physical nature. Water-soluble alkali (such as Mg or Na) in particulate-laden gas streams has been known to poison SCR catalysts. Space considerations for installing a catalyst section in an existing boiler's ductwork are also important. Also note the use of solid fuels can result in catalyst contamination even with efficient PM control system and high moisture levels in exhaust air would result in inefficient SCR operation.[64]

Most boilers feature a flue gas temperature at the economizer exit that is below the ammonium sulfate/bisulfate dew point. Air heater surfaces must withstand corrosion from ammonium sulfates and bisulfates, be easily cleaned with conventional soot blowing, and survive corrosion-inducing water washing. SO_3 produced by the catalyst may condense on cooler surfaces, depending on the temperature, during both steady-state and non-steady-state operation. Higher levels of SO_2 to SO_3 conversion could cause accelerated corrosion or higher SO_3-induced plume opacity. Minimizing ammonia levels in the stack (typically <2 to 3 ppm) is required to avoid problems with disposal of scrubber byproduct contaminated by ammonia. The use of a particular catalyst puts restrictions on the fuel flexibility for a boiler. For example, purchasing coal with fly ash containing calcium oxide and arsenic outside the defined range absolves the catalyst supplier from responsibility for arsenic poisoning.[65]

The only "wood-fired" boiler SCR application in service in the U.S. was located at a woodworking facility in Ohio. This SCR was located downstream of a mechanical collector and electrostatic precipitator, operating in flue gas temperatures ranging from 550 to 650 °F. The only problem reported at this

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[62] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

[63] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[64] Ibid.

[65] Ibid.

installation was minor catalyst blinding due to the deposition of fine particulate that escaped the PM collection devices. It was learned the operating temperature for this SCR system allowed the use of conventional catalysts designed to accommodate high dust applications. For these catalysts, the catalyst openings through which the flue gas flows are sized to provide proper surface area contact and sufficient flue gas velocity to minimize fouling. Low temperature catalyst designs are considerably different and would not be recommended for use on any high dust application. Based on this description of the air pollution control system configuration and the operating conditions for this particular wood-fired boiler, it is important to identify several specific differences between this installation and those that operate in the FPI. First, due to the requirement to provide hot air to burn all but the driest of wood fuels, wood-fired boilers are usually equipped with air preheaters. Thus, even when dry particulate control devices like an ESP are utilized, the installation of an SCR catalyst section after a PM control device is not amenable for adaptation to such boilers without, of course, incurring a severe energy penalty. Second, a significant portion of the FPI's wood-fired boilers is controlled for PM emissions by multiclones and wet scrubbers. Therefore the PM emissions from these would be higher than the example situation. Third, it is unclear how the Ohio facility's SCR system would have worked under the fluctuating boiler load characteristics common to many FPI boilers. Finally, sawdust, which was the fuel fired in the Ohio facility's boiler, is a low moisture fuel and the particulate matter present in the flue gases from its combustion is likely to be of different composition than when bark or hog fuel (typically much higher moisture) is burned.[66]

Hence the use of SCR technology has clearly not been demonstrated for industrial wood, biomass or combination fuel-fired boilers in the FPI.[67]

4.4.3 STEP 3 – EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

Table 4-2 presents a ranking of the technically feasible control strategies in order of their effectiveness (i.e., potential control efficiency). For controls with a range of performance levels, the BART Guidelines note:

> *It is not [the U.S. EPA's] intent to require analysis of each possible level of efficiency for a control technique as such an analysis would result in a large number of options. It is important, however, that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving.*

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[66] Ibid.

[67] Ibid.

TABLE 4-2. RANKING OF CONTROL STRATEGIES

Control Strategy	Applicability	Potential Control Efficiency (%)
MdN	No. 1 & No. 2 Boilers	50 [a]
OFA Upgrades	No. 1 & No. 2 Boilers	40 [a]
LNB	No. 2 Boiler Only	30 [b,c]
Original OFA + Boiler Tuning/Optimization	No. 1 Boiler	Base Case
Original OFA + NO_X Air + Fuel Blending + Boiler Tuning/ Optimization	No. 2 Boiler	Base Case

[a] Based on estimate from Energy System Associates.
[b] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.
[c] Based on estimate from B&W.

Note that MdN is included in Table 4-2 despite its questionable technical feasibility.

4.4.4 STEP 4 – EVALUATE IMPACTS AND DOCUMENT RESULTS

The technically feasible control technologies are evaluated on the basis of (1) costs of compliance, including consideration of the remaining useful life, (2) energy impacts, and (3) non-air quality environmental impacts.

For the purposes of this analysis, energy and non-air quality environmental impacts are considered minimal for all the technically feasible control options listed in Table 4-2. Per the BART Guidelines, the costs of compliance analysis for each control option consists of comparisons of the average cost effectiveness and the incremental cost effectiveness, which are defined in Section IV.D.4 as follows:

> *Average cost effectiveness means the total annualized costs of control divided by the annual emissions reduction (the difference between baseline annual emissions and the estimate of emissions after controls), using the following formula:*
>
> *Average cost effectiveness (dollars per ton removed) = Control option annualized cost ÷ (Baseline annual emissions – Annual emissions with Control option)*
>
> *…the incremental cost effectiveness calculation compares the costs of performance level of a control option to those of the next most stringent option, as shown in the following formula (with respect to cost per emissions reduction):*

Incremental Cost Effectiveness (dollars per incremental ton removed) = (Total annualized costs of control option) – (Total annualized costs of next control option) ÷ (Control option annual emissions) – (Next control option annual emissions)

The average and incremental (where applicable) cost effectiveness for each feasible control option for the Ashdown Mill's No. 1 and No. 2 Power Boilers are summarized in Table 4-3. Detailed control costs calculations are presented in Appendix B.

TABLE 4-3. CONTROLS COSTS SUMMARY

				Cost Effectiveness	
Emission Unit	**Control Strategy**	**Total Annualized Cost (MM$)**	**NO_X Removed (tpy)**	**Average ($/ton)**	**Incremental ($/ton)**
No. 1 Power Boiler	MdN	3.94	542	7,262	17,354
	OFA Upgrades	2.06	434	4,740	N/A
No. 2 Power Boiler	MdN	5.35	1,257	4,259	9,571
	OFA Upgrades	2.95	1,006	2,931	7,329
	LNB	1.10	754	1,465 [b]	N/A

[b] This estimate is consistent with NCASI's Special Report 03-04, which states, "for pulverized coal boilers, a 30 percent NO_X reduction could be achieved with LNB at a cost of <$2,000/ton."

Based on Domtar's analysis, both MdN and OFA upgrades are considered cost prohibitive for both the No. 1 and No. 2 Power Boilers and are ruled out as BART options. Based on steps 1 through 4 of the BART determination analysis, no retrofit controls are available for the No. 1 Power Boiler and LNB is the best available retrofit control technology for the No. 2 Power Boiler.

PROPOSED BART DETERMINATIONS FOR NO_X

For the No. 2 Power Boiler, Domtar proposes a NO_X BART limit of 1,759.9 tpy. Compliance with this limit will be demonstrated by a CEMS. The current permit limit of 1,084.1 tpy is proposed as BART for the No. 1 Power Boiler.

A summary of all proposed BART determinations is provided in Table 4-4. Please note that while example control technologies theoretically capable of achieving the proposed BART limits are listed, Domtar reserves the right to implement other equivalent control strategies between now and the BART effective date (~2013) to meet the same emission limits.

TABLE 4-4. SUMMARY OF PROPOSED BART DETERMINATIONS

Emission Unit	**Pollutant**	**BART Limit**	***Example Control Technology***
No. 1 Power Boiler	PM	0.07 lb/MMBtu (Boiler MACT)	*WESP*
	SO_2	214.0 tpy (Current Permit Limit)	*N/A*
	NO_X	1084.1 tpy (Current Permit Limit)	*N/A*
No. 2 Power Boiler	PM	0.07 lb/MMBtu (Boiler MACT)	*Wet Scrubber*
	SO_2	4,305.5 tpy (Current Permit Limit)	*Wet Scrubber*
	NO_X	1,759.9 tpy (30 Percent Control)	*LNB*

4.5 STEP 5 – EVALUATE VISIBILITY IMPACTS

The degree of visibility improvement is assessed based on the change in modeled impacts for the pre-control (i.e., the BART applicability analysis) and post-control (i.e., the predicted maximum 24-hour emission rate after implementation of BART) emission scenarios. Per the BART Guidelines, this assessment "may consider the frequency, magnitude, and duration components of [visibility] impairment."

The post-control modeling for the visibility improvement analysis was conducted using the CALPUFF modeling system in the same manner as the ADEQ's BART applicability analysis, which is described in Section 3 of this report and in the Protocol (see Appendix A). In fact, the post-control modeling was conducted using the same CALPUFF, POSTUTIL, and CALPOST input files generated by the ADEQ for the applicability analysis. The only changes made to these files for the post-control modeling was to the emissions rates and stack parameter changes associated with implementing the chosen BART controls. Table 4-5 and Table 4-6 summarize the maximum 24-hour average emission rates and the stack parameters, respectively, that were modeled in the post-control analysis.

TABLE 4-5. SUMMARY OF 24-HOUR AVERAGE MAXIMUM POST-CONTROL EMISSION RATES

Emission Unit	NO_X Emissions (lb/hr)	SO_2 Emissions (lb/hr)	Total PM Emissions (lb/hr)
No. 1 Power Boiler	179.6	6.1	40.6
No. 2 Power Boiler	289.0	557.0	57.4

TABLE 4-6. POST-CONTROL STACK PARAMETERS

Emission Unit	LCC East (km)	LCC North (km)	Elevation (m)	Stack Height (m)	Stack Diameter (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)
No. 1 Power Boiler	267.47491	-698.66686	97.5	66.1	1.890	522	26.76
No. 2 Power Boiler	267.48245	-698.74355	97.5	71.6	3.659	325	11.92

Visibility improvement is quantified and judged in a cumulative matter. That is, to compare to the pre-control modeling analysis executed by the ADEQ, Domtar's post-control modeling analysis simulated all emissions reductions from both emission units. Note that since maximum applicability analysis impacts were less than 0.5 Δdv for the Hercules-Glades and Sipsey Class I areas, these areas were not evaluated in the post-control scenario. Table 4-7 summarizes the results of the visibility improvement analysis.

TABLE 4-7. SUMMARY OF VISIBILITY IMPROVEMENT ANALYSIS RESULTS

Class I Area	Maximum 24-hour Impact (Δdv) [a]	Number of Days > 0.5 Δdv [a]	Number of Days > 1.0 Δdv [a]
Caney Creek	1.286	64	8
Upper Buffalo	0.668	1	0
Mingo	0.497	0	0

[a] For total modeled period: years 2001, 2002, and 2003.

As shown in Table 4-7, the application of BART on the Ashdown Mill's No. 1 and No. 2 Power Boilers results in significant visibility impacts improvement in the affected Class I areas by eliminating any visibility impairment in Class I areas outside of Arkansas. Visibility impairment at Upper Buffalo was reduced by 81 percent while impairment at Caney Creek was reduced by 41 percent (based on total impact and excluding any days with impacts less than 0.50 Δdv). The number of days within the modeled three-year period with impacts greater than 0.50 Δdv decreased from 96 to 64 for the Caney Creek Class I area and from six to only one day for the Upper Buffalo Class I area.

In addition to the cumulative analysis, the ADEQ requested emission unit specific and pollutant specific modeling. Since cumulative analysis impacts in the Upper Buffalo and Mingo Class I areas are minimal, the emission unit and pollutant specific modeling was only conducted for the Caney Creek Class I area. The results of these pre- and post-control analyses (each conducted for the entire modeling period: year 2001, 2002, and 2003) are presented in Table 4-8.

TABLE 4-8. EMISSION UNIT & POLLUTANT SPECIFIC MODELING RESULTS

Emission Unit	Pollutant	Pre-Control Scenario		Post-Control Scenario	
		Max. 24-hour Impact (Δdv)	Number of Days > 0.5 Δdv	Max. 24-hour Impact (Δdv)	Number of Days > 0.5 Δdv
No. 1 Power Boiler	PM	0.270	0	0.065	0
	SO_2	0.008	0	0.008	0
	NO_X	0.398	0	0.398	0
No. 2 Power Boiler	PM	0.104	0	0.095	0
	SO_2	0.743	4	0.743	4
	NO_X	0.849	17	0.602	4
No. 1 & 2 Power Boilers	PM	0.362	0	0.156	0
	SO_2	0.750	4	0.750	4
	NO_X	1.213	41	0.975	24

Additionally, as requested by the ADEQ in its September 8, 2006, letter, Domtar's post-control (and pre-control, where different from the ADEQ's applicability modeling files) CALPUFF, POSTUTIL, and CALPOST input files and CALPOST output files are included with this report on electronic media. The file naming convention is explained below. Note that all filenames contain the "doas" root (characters 4 through 7) to denote Domtar – Ashdown. Note also that path names will need to be modified to represent the user's directory structure when replicating these analyses.

File Naming Convention:

*xx*_doas*yyz*.*fff*

where:

xx = Model:
cp = CALPUFF
pu = POSTUTIL
ct = CALPOST

yy = Year:
01 = 2001
02 = 2002
03 = 2003

z = Class I area: (for cumulative analysis*)
c = Caney Creek
m = Mingo
u = Upper Buffalo

fff = File type:
inp = Input
lst = Output (CALPOST only)

* All emission unit and source specific analyses were conducted for the Caney Creek Class I area only so the *z* character is not used to denote Class I area for the CALPUFF and POSTUTIL input files for these models (it is used, but it is expanded as discussed below, for the CALPOST input and output files). For these models, the *z* character represents a model run identifier (and may be more than one character). The path and filename for each emission unit and source specific model run included with this report is listed below.

No 1. PB – PM Only – Pre-Control	..\SN3_ABE\xx_doasyyA.fff
No 1. PB – PM Only – Post-Control	..\SN3_CD\xx_doasyyD.fff
No 1. PB – SO$_2$ Only – Pre/Post-Control	..\SN3_ABE\xx_doasyyB.fff
No 1. PB – NO$_X$ Only – Pre/Post-Control	..\SN3_CD\xx_doasyyC.fff
No 2. PB – PM Only – Pre-Control	..\SN5_Only\xx_doasyyA.fff
No 2. PB – PM Only – Post-Control	..\SN5_Only\xx_doasyyD.fff
No 2. PB – SO$_2$ Only – Pre/Post-Control	..\SN5_Only\xx_doasyyB.fff
No 2. PB – NO$_X$ Only – Pre-Control	..\SN5_Only\xx_doasyyC.fff
No 2. PB – NO$_X$ Only – Post-Control	..\SN3_SN5 All_NOX\ xx_doasyyF2.fff
Both PBs – PM Only – Pre-Control	..\SN3_SN5\xx_doasyyA.fff
Both PBs – PM Only – Post-Control	..\SN3_SN5\xx_doasyyD.fff
Both PBs – SO$_2$ Only – Pre/Post-Control	..\SN3_SN5\xx_doasyyB.fff
Both PBs – NO$_X$ Only – Pre-Control	..\SN3_SN5\xx_doasyyC.fff
Both PBs – NO$_X$ Only – Post-Control	..\SN3_SN5 All_NOX\ xx_doasyyF4.fff

APPENDIX A – ADEQ'S DRAFT BART MODELING PROTOCOL

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Draft
BEST AVAILABLE RETROFIT TECHNOLOGY (BART) MODELING PROTOCOL

June 7, 2006

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I. Introduction

On 6 July 2005, the U.S. Environmental Protection Agency (EPA) published final amendments to its 1999 Regional Haze Rule in the Federal Register, including Appendix Y, the final guidance for Best Available Retrofit Technology (BART) determinations (70 FR 39104-39172). The BART rule requires the installation of BART on emission sources that fit specific criteria and “may reasonably be anticipated to cause or contribute” to visibility impairment in any Class I area. Air quality modeling is the preferred method for establishing which emission sources cause or contribute to visibility impairment. Arkansas’ BART modeling protocol is provided herein.

According to the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determination; Final Rule (40 CFR Part 51, p 39125), each state is required to develop a BART Modeling Protocol that describes the required methodology to assess the levels of controls needed on sources subject to BART. The aforementioned regulation also requires states to work in partnership with all stakeholders including Tribes, EPA, Federal Land Managers (FLMs), Regional Planning Organizations (RPOs) and the various source operators. Although states are required to work in concert with the previously mentioned stakeholders, EPA has the ultimate authority to approve or disapprove a state’s State Implementation Plan (SIP).

The main objective of this protocol is compliance with the RHR visibility improvement goals. To accomplish this goal, the Arkansas Department of Environmental Quality (ADEQ) has set forth three functions of this protocol. First, ADEQ will use the protocol to determine which BART-eligible units are subject-to-BART and must perform a BART-analysis. Second, facilities that ADEQ notifies that are subject-to-BART will use this protocol to conduct post-control modeling required for their BART-analysis. Third, the results from this protocol will be used to conduct cumulative modeling to show the change in visibility impact on Class I areas based on ADEQ’s BART determination and the BART emission limits for facilities based on their BART-analysis. The subject-to-BART and final modeling will be submitted to the EPA as part of the BART section of the Arkansas State Implementation Plan (SIP) for Regional Haze.

The AR RH SIP submittal deadline to EPA as set forth in the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determination; Final Rule (40 CFR Part 51, p 39156) is December 17, 2007. To meet this deadline, ADEQ has developed a schedule for completing BART determinations and implementing the BART strategy in order to meet the mandatory SIP submittal deadline (Appendix A). As shown in Appendix A, the modeling results must be completed no later than March 1, 2007.

The Central States Regional Planning Association (CENRAP) contracted with Alpine Geophysics, LLC to develop a modeling protocol for the states within CENRAP’s region of which the state of Arkansas is a member. On December 22, 2005, Alpine Geophysics, LLC delivered the final version of the CENRAP BART Modeling Guidelines (Tesche, et al, 2005). However, comments from EPA Regions VI and VII and the Federal Land Managers (FLMs) were not incorporated into the guidelines; thus, Alpine Geophysics, LLC rewrote the guidelines to reflect the comments from Regions VI and VII and FLMs. These guidelines were re-issued February 3, 2006. Hence, CENRAP's BART Modeling Guidelines (Tesche, et al, 2005) have been approved by Regions VI and VII and the FLMs. Therefore, the Planning and Air Quality Analysis Branch, Air Division, Arkansas Department of Environmental Quality has chosen to adopt the CENRAP BART Modeling Guidelines as ADEQ's BART Modeling Protocol. Additionally, in preparing this draft protocol, ADEQ also consulted the following draft BART modeling protocols:

1. Best Available Retrofit Technology (BART) Modeling Protocol to Determine Sources Subject to BART in the State of Kansas draft version February 24, 2006
2. Best Available Retrofit Technology (BART) Modeling Protocol to Determine Sources Subject to BART in the State of Minnesota draft version February 24, 2006

This draft protocol is most similar to the CENRAP BART Modeling Guidelines. These guidelines were developed to ensure "consistency between states in the development of BART modeling protocols and to harmonize the approaches between adjacent RPOs" (Tesche, et al, 2005).

Soon after the finalization of this modeling protocol, ADEQ will notify sources subject-to-BART. For those facilities subject-to-BART, ADEQ will provide guidance for conducting their BART-analyses.

II. Background

The Clean Air Act Amendments (CAAA) of 1977 established 156 Class I areas where visibility was determined to be an important value (Figure 1). Areas designated as Class I areas are those national parks exceeding 6000 acres, wilderness areas and national memorial parks exceeding 5000 areas, and all international parks that were in existence on August 7, 1977. While Rainbow Lake Wilderness Area, Wisconsin has been designated as a Class I area, the FLMs have indicated that visibility is not a valuable characteristic and therefore, is not included in BART or other RH analyses.

The state of Arkansas has within her boundary two mandatory Class I federal areas (Class I area), Upper Buffalo Wilderness Area and Caney Creek Wilderness Area which are managed by the United States Forest Service (Figure 2). However, there are two Class I areas in southern Missouri that are located downwind of facilities operating in Arkansas. The Missouri Class I areas are Hercules-Glade Wilderness Area (US Forest Service) and Mingo National Wildlife Refuge (US Fish and Wildlife). While EPA has not listed the maximum distance from a Class I area to model, this criteria has been set by CENRAP as 300 km. As shown in Figure 3, the eastern portion of Arkansas is within the 300 km radius of Sipsey Wilderness Area (US Forest Service), Alabama. Therefore, there are five Class I areas Arkansas will be performing BART determination/exemption modeling (Table 1).

Figure 1 Mandatory Class I federal areas in the United States of America

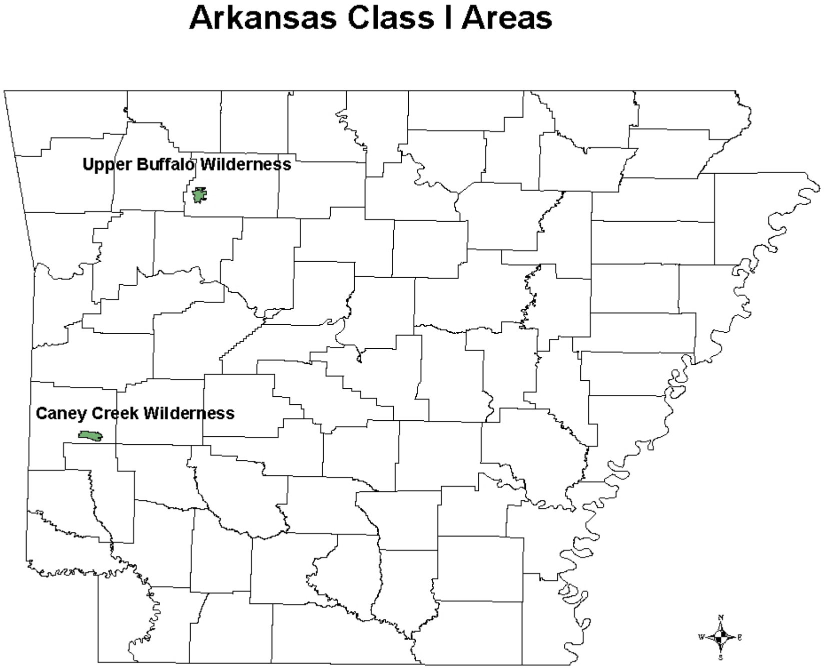

Figure 2 Arkansas’s Class I areas

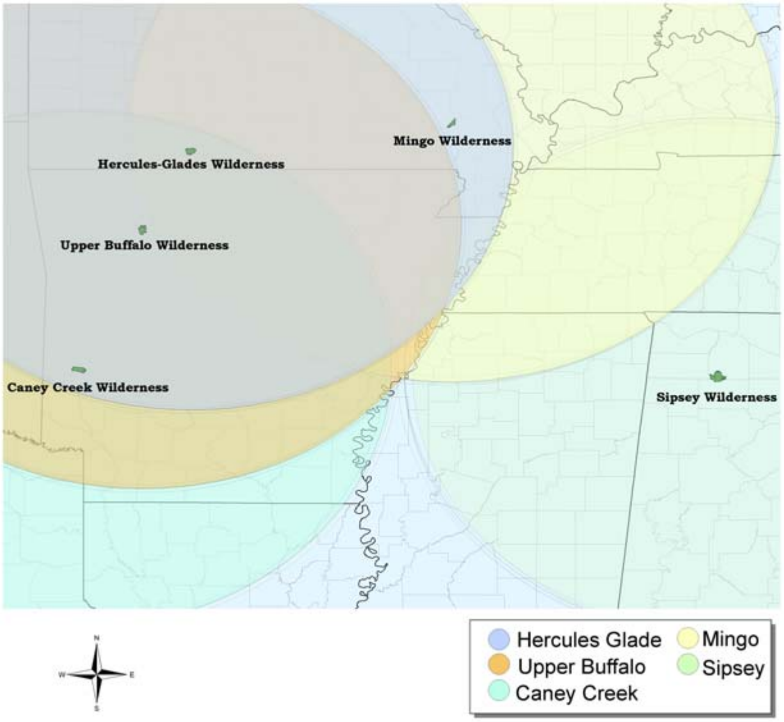

Figure 3 Map showing the 300 km radius buffer zones around five separate receptors (north, south, east, west, and center) located in the following Class I areas: Upper Buffalo, Caney Creek, Hercules Glade, Mingo, and Sipsey. This map was developed to determine which Class I areas will be assessed during the BART determination modeling

Table 1 Class I areas and the State they are located in as well as the supervising agencies ADEQ will evaluate during the BART determination/exemption modeling

Class I Area	State	Supervising Agency
Upper Buffalo Wilderness Area	AR	U.S. Forest Service
Caney Creek Wilderness	AR	U.S. Forest Service
Hercules Glade Wilderness Area	MO	U.S. Forest Service
Mingo NWS	MO	U.S. Fish and Wildlife
Sipsey Wilderness Area	AL	U.S. Forest Service

III. BART-Eligible Sources

The BART requirements in the RHR are intended to reduce emissions specifically from large emission units that, due to age, were exempted from other control requirements of the CAAA. For an emissions unit to be considered eligible for BART, it must fall into one of 26 specified categories, must have the potential to emit at least 250 tons per year of certain haze-forming pollutants, and must have been in existence on August 7, 1977, but not in operation before August 7, 1962.

ADEQ staff determined Arkansas' BART-eligible sources by first identifying which of Arkansas' stationary sources fit the first criteria of being listed in the BART 26 specific categories. After identifying the sources which fit the first criteria, a database search of these facilities was performed to determine whether or not these emitting units' potential to emit were at least 250 tons per year of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM). The next stage of determining BART-eligibility was to research the permit applications for the year the point source was placed into operation. The final step in the process was to contact facilities for the exact date of operation especially for sources that were placed into operation in the years 1977 and 1962. Tables 2 and 3 contain the list of BART-eligible facilities (18) by BART source category and the number of BART-eligible emitting units (27) within each facility. Figure 4 is a map of Arkansas which shows the location of the 18 BART-eligible facilities located in Arkansas. Figure 5 depicts the five Class I areas Arkansas will be assessing and the BART-eligible sources in Arkansas. Appendix B contains maps showing the receptors at each Class I area ADEQ will be assessing.

Table 2 Fossil fuel-fired steam electric plants > 250 MMBtu/hr and Kraft pulp mills facilities with BART-eligible emission units

BART Source Category Number and Name	Facility Name/Location	Facility ID	AFIN	Unit ID	Unit Description
1. Fossil fuel-fired Electric Plants > 250 MMbtu/hour – Electric Generating Units (EGUs)	American Electric Power (SWEPCO)/Gentry	05-007-00107	04-0017	SN-01	Boiler
	AR Electric Cooperative/Augusta	05-147-00024	74-00024	SN-01	Boiler 1350mm
	AR Electric Cooperative/Camden	05-103-00055	52-00055	SN-01	Boiler
	Entergy – Lake Catherine/Jones Mill	05-059-00011	30-00011	SN-03	Unit 4 Boiler
	Entergy – Ritchie Plant/Helena	05-107-00017	54-00017	SN-02	Unit 2
	Entergy – White Bluff/ Redfield	05-069-00110	35-00110	SN-01	Unit 1
	Entergy – White Bluff/Redfield	05-069-00110	35-00110	SN-02	Unit 2
	Entergy – White Bluff/Redfield	05-069-00110	35-00110	SN-05	Auxiliary Boiler
3. Kraft Pulp Mills	Domtar, Inc./Ashdown	05-081-00002	41-00002	SN-03	#1 Power Boiler
	Domtar, Inc./Ashdown	05-081-00002	41-00002	SN-05	#2 Power Boiler
	Delta Natural Kraft/Pine Bluff	05-069-00017	35-00017	SN-02	Recovery Boiler
	Georgia – Pacific Paper/Crossett	05-003-00013	02-00013	SN-22	9A Boiler
	Green Bay Packing/ Morrilton	05-029-00001	15-00001	SN-05A	Recover Boiler
	Potlatch/McGehee	05-041-00036	21-00036	SN-04	Power Boiler

Table 3 Petroleum refineries, sintering plants and chemical processing plant facilities with BART-eligible emissions units

BART Source Category Number and Name	Facility Name/Location	Facility ID	AFIN	Unit ID	Unit Description
11. Petroleum Refineries	Lion Oil/El Dorado	05-139-00016	70-00016	SN-809	#7 Catalyst Regenerator
19. Sintering Plants	Big River Industries /West Memphis	05-035-00082	198-00082	SN-01	Kiln A
21. Chemical Processing Plants	Albermarle – South Plant/Magnolia	05-027-00028	14-00028	SR-01	Tail Gas Incinerator
	Albermarle – South Plant/Magnolia	05-027-00028	14-00028	BH-01	Boiler #1
	Albermarle – South Plant/Magnolia	05-027-00028	14-00028	BH-02	Boiler #2
	Eastman Chemical/Batesville	05-063-00036	32-00036	6M01-01	3 Coal Boilers
	El Dorado Chemical/El Dorado	05-139-00040	70-00040	SN-08	West Nitric Acid Plant
	El Dorado Chemical/El Dorado	05-139-00040	70-00040	SN-09	East Nitric Acid Plant
	El Dorado Chemical/El Dorado	05-139-00040	70-00040	SN-10	Nitric Acid Concentrator

Arkansas Class I Areas and BART-Eligible Facilities

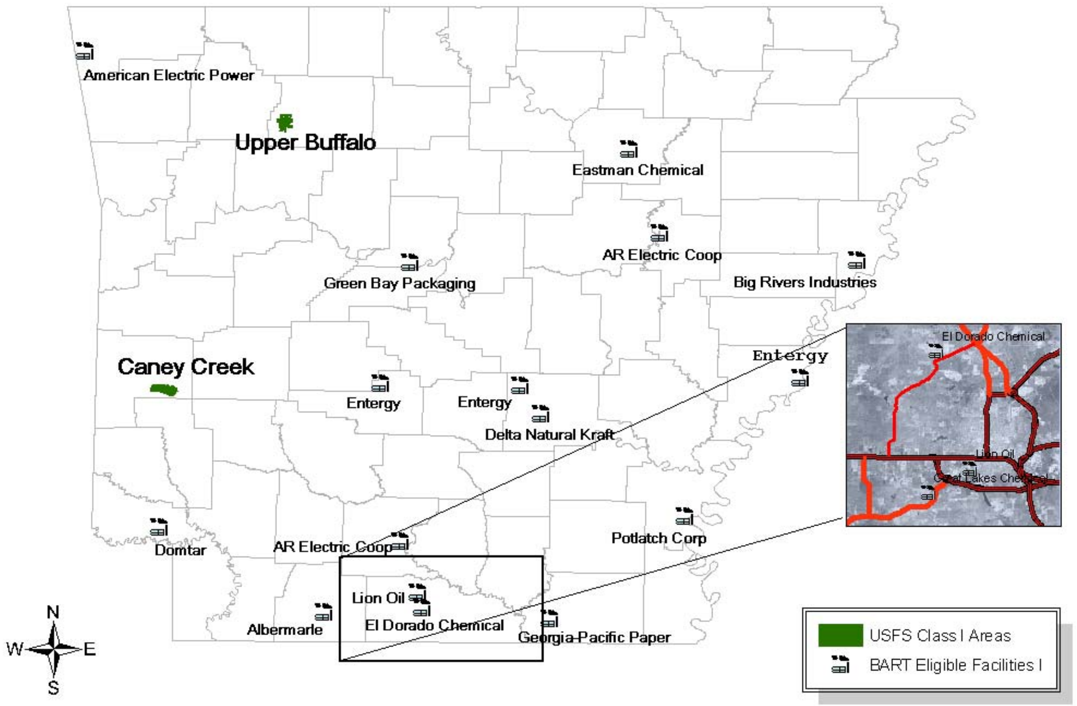

Figure 4 Map indicating the locations of Upper Buffalo, Caney Creek and the eighteen BART-eligible facilities located in Arkansas

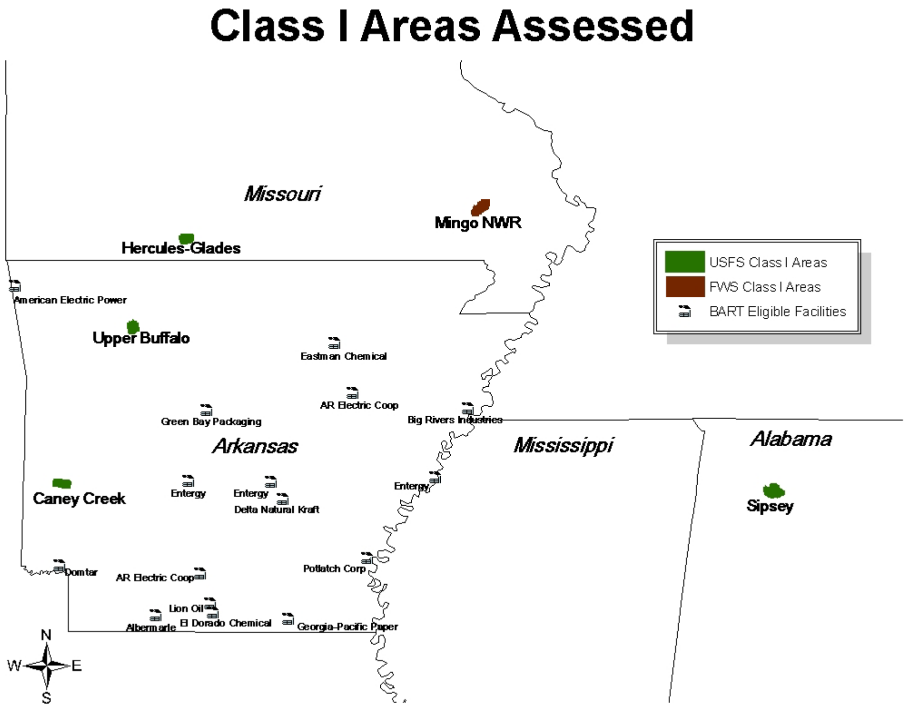

Figure 5 Map indicating the locations of Upper Buffalo, Caney Creek, Hercules Glade, Mingo and the eighteen BART-eligible facilities located in Arkansas

IV. CAIR and Arkansas

The Clean Air Interstate Rule was finalized in May 2005 by EPA and applies to states in the eastern U.S. Reconsiderations were finalized March 2006. This rule address air pollution transport across state borders. EPA determined which states must reduce which pollutants based on modeling which showed how the travel of pollution affects non-attainment in other states. CAIR requires states to reduce NO_x and/or SO_2 emissions. Of the three programs in CAIR, Arkansas is required to participate in only the Ozone-Season NO_x reductions program. Although EPA's BART Modeling Guidance allows CAIR states to participate in the CAIR cap and trade program, the state of Arkansas is not eligible for the aforementioned trading program because Arkansas is in CAIR only for NO_x during the ozone season. Therefore, in Arkansas CAIR **is not better** than BART. Thus BART-eligible EGUs will be modeled for BART determination/exemption by ADEQ.

V. BART Air Quality Modeling Approach

According to EPA's BART Modeling Guidance, "CALPUFF is the best regulatory modeling application currently available … and is currently the only EPA-approved model…" (p 45); therefore, ADEQ and CENRAP have chosen to use CALPUFF in the

BART determination process as well as in the post-control analysis. One of the air quality modeling approaches suggested by EPA in the BART guidance is an individual source attribution approach. This is the approach ADEQ proposes to take. Specifically, this entails modeling source-specific units and comparing modeled impacts to a particular deciview threshold (described below). ADEQ has decided to conduct the subject-to-BART modeling, rather than have each BART-eligible facility either conduct the modeling or hire a contractor. This plan will eliminate the need for ADEQ to quickly review many air quality modeling analyses conducted using varying approaches. This plan will also satisfy the need to use a consistent approach among the modeling analyses. Once the subject-to-BART modeling is complete, all the modeling inputs will be available to facilities subject to BART for them or their consultants to conduct modeling for making BART analyses.

ADEQ will follow EPA's BART Modeling Guidance (p 42) in sitting a threshold limit in determining whether a BART-eligible source is either subject-to-BART or exempt. According to the aforementioned modeling guidance, an individual source will be considered to "cause visibility impairment" if the emissions results in a change (delta Δ) in deciviews (dv) that is greater than or equal to 1.0 deciview on the visibility in a Class I area. Additionally, if the emissions from a source results in a change in visibility that is greater than or equal to 0.5 dv in a Class I area the source will be considered to "contribute to visibility impairment" (BART Final Rule, 40 CFR 51 p 39113). Thus, ADEQ has set the threshold limit at **0.5 dv**.

The modeling approach discussed here is specifically designed for conducting the subject-to-BART screening analyses. There may be differences between modeling for conducting BART analyses and that for conducting a visibility analysis for a New Source Review permit, which may involve similar emission sources and the same air dispersion model used here.

To **ensure** that no sources pass the screening test when they should fail, the simple approach, by its nature, must be the most conservative of all the conditions likely to be examined for the source in question. For example, many factors influence the contribution of a source to the Class I area other than distance. The frequency of winds transporting the pollutants toward the Class I area may often be important to include for a reliable screening analysis. Also, a more distant Class I area downwind in the predominant wind direction from a source may receive a higher visibility impact than a closer Class I area that is infrequently downwind of the source. Another example of conservatism in the screening process is the use of the latest beta version of the CALMET/CALPUFF modeling system using the no-observation (no-obs) mode (the prognostic meteorological model MM5). Thus, the **maximum** impact instead of the 98th percentile will be used to determine if a source has an impact on visibility in a Class I.

Additionally, the BART analysis process includes several other steps in addition to the modeling described in this protocol (EPA, 2005). These steps, none of which are addressed in this document, include detailed analysis of:

- Costs of compliance among the various retrofit control options
- Energy and non-air quality impacts
- Existing pollution control technologies in use at the BART-eligible unit particularly with respect to their affecting the choice of retrofit options
- Remaining useful life of the units and/or facility
- Improvements in visibility expected from the use of BART controls.

VI. BART-Eligible Units Physical Parameters

The physical characteristics of the BART-eligible point sources to be used for the screening stage one analysis will be provided by ADEQ staff. For the stage two screening analysis, ADEQ staff will work with the BART-eligible facilities in the development of actual emissions.

A. Stack Parameters

Stack parameters required for modeling BART-eligible units were extracted from the permit applications. Stack parameters include height of the stack opening from ground in meters, inside diameter in meters, exit velocity in meters per second, exit gas temperature in Kelvin, ground elevation of the stack base in meters, and location coordinates of the stack in Lambert Conformal Conical (LCC). The stack coordinates were taken (in Universal Transverse Mertcator, UTM, and then converted to LCC) by ADEQ staff and then verified using ArcMap. Because the BART modeling focuses on mesoscale transport to Class I areas, other source term parameters (needed to calculate localized impacts) such as building heights and widths for calculating downwash will not be used. Appendix C contains tables indicating the stack parameters and coordinates for each BART-eligible emitting unit.

B. Emission rates

ADEQ notified by email the BART-eligible facilities to provide the 24-hour average **actual** emission rate with normal operations from the highest emitting day of the year. Excluded from consideration are days where start-up, shutdown or malfunctions occurred unless these activities are regular, frequently occurring components of the source's operation cycle.

ADEQ does not intend to use emissions of VOCs and ammonia from facilities for subject-to-BART analysis. Only specific VOC compounds form secondary organic aerosols that affect visibility. These compounds are a fraction of the total VOCs reported in the emissions inventory, and ADEQ does not have the breakdown of VOC emissions necessary to model those that only impair visibility. Further, the prescribed screening model (CALPUFF) cannot simulate formation of particles from anthropogenic VOCs, nor their visibility impacts. Ammonia from specific sources will not be evaluated in this process, although ammonia is included in the modeling as a background concentration—this will be discussed later in this modeling protocol. The appropriate VOCs and ammonia emission data can, and will be, included in regional scale modeling used for the Regional Haze SIP.

VII. Air Quality Model and Inputs

As stated in the previous section, CALPUFF is the preferred regulatory air dispersion model for long distance and therefore is the model ADEQ will be using in the BART determination process. ADEQ recognizes that CALPUFF has limited ability to simulate the complex atmospheric chemistry involved in the estimation of secondary particulate formation. However, for purposes of the subject-to-BART analysis, ADEQ intends to use CALPUFF for the following reasons:

1. The increased level of effort required for conducting particulate apportionment in the regional scale, full-chemistry Eulerain model (CAMx) to acquire individual source contributions to Class I areas, relative to the simplicity of the CALPUFF model
2. The lack of a plume-in-grid feature with the particulate apportionment technique currently available in CAMx
3. The desire to be consistent with other CENRAP states, which all (except Texas and Iowa) appear to be using CALPUFF
4. The limited scope of what this modeling is to determine
5. The additional modeling of BART controls that will be conducted as part of the Regional Haze SIP with the CAMx or CMAQ model(s). EPA's BART guidance states that States should follow the EPA's Interagency Workgroup on Air Quality Modeling (IWAQM) guidance, Phase 2 recommendations for long-range transport. The IWAQM guidance was developed to address air quality impacts as assessed through the Prevention of Significant Deterioration (PSD) program at Class I areas, where the source generally is located beyond 50 km of the Class I area. The IWAQM guidance does not specifically address the type of assessment that will occur with the BART analysis.

EPA recommends in their BART modeling guidelines (2005) that States follow the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase II (1998) for long-range transport. The IWAQM guidance was developed to address air quality impact – as assessed through the Prevention of Significant Deterioration (PSD) program – at Class I areas, where the source generally is located beyond 50 km of the Class I area. The IWAQM guidance does not specifically address the type of assessment that will occur with the BART modeling.

A. CALPUFF Screening Modeling:

CALPUFF modeling will be performed on all Arkansas BART-eligible sources. ADEQ intends to closely follow the CENRAP BART modeling protocol for most of the settings and inputs. Kansas attempted puff splitting and found this method to be computationally prohibitive on the current domain (State of Kansas, 2006). Also, according to Tesche, et al (2005),

> "There is no quantitative evidence that the horizontal and vertical puff-splitting algorithms in CALPUFF yield improved accuracy and precision in model estimates of inert or linearly reactive pollutants although conceptually the methods have appeal in that they attempt to mimic lateral and vertical wind speed and direction shears." (p 6-6)

Therefore, ADEQ will not invoke puff splitting in the no-obs screening analysis nor in the refined screening analysis. However, if a potentially subject-to-BART facility wishes to invoke the puff splitting mode, they will be required to notify ADEQ in writing of their intent and provide a protocol for approval prior to performing the analysis.

1. Modeling domain

The CALPUFF modeling will be conducted on the CENRAP central 6 km grid. The extent of the proposed CALPUFF domain is shown in Figure 2.

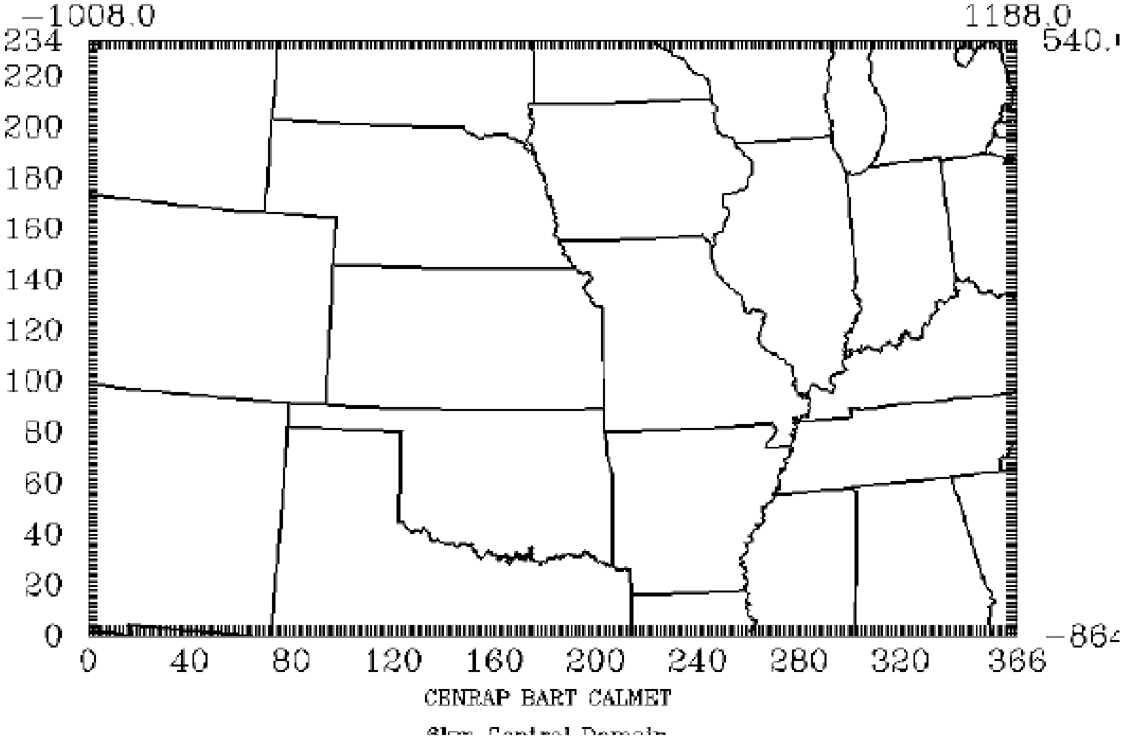

Figure 6 6 km CENRAP Central CALPUFF domain (Tesche, et al, 2005)

CALPUFF will be applied to each source for three annual simulations spanning the years 2001 through 2003. The IWAQM Phase II guidance allows the use of fewer than 5 years of meteorological data if a meteorological model using four-dimensional data assimilation is used to supply data. This is the case in this modeling analysis. See the section on meteorology for more information.

2. CALPUFF system implementation

There are three main components to the CALPUFF model:

1. Meteorological Data Modeling (CALMET);
2. Dispersion Modeling (CALPUFF); and
3. Post-processing (CALPOST)

Versions of the modeling components to use in this BART analysis are shown in Table 4.

Table 4 CALPUFF Modeling Components

Processor	Version	Level
TERREL	3.311	030709
CTGCOMP	2.42	030709
CTGPROC	2.42	030709
MAKEGEO	2.22	030709
CALMM5	2.4	050413
CALMET	5.53a	040716
CALPUFF	5.753	051130
POSTUTIL	1.4	040818
CALPOST	5.6392	051130

The specific use of each of these components in the BART analysis is described in more detail below.

For screening applications, ADEQ will use the VISTAS version which is the latest 'beta' versions of the CALMET/CALPUFF modeling system. Note that these are **not** the EPA guideline codes but rather an updated version containing recent (as of this writing) science improvements and bug fixes. The current guideline CALPUFF code is version 5.7, level 030402. This substitution results from EPA phasing out the use of the legacy Pasquill-Gifford (P-G) dispersion parameters with the introduction of AERMOD as a new guideline model. CALPUFF employs the AERMOD turbulence-based dispersion coefficients and probability density function (pdf) dispersion methods scheme instead of P-G.

The appropriate model codes may be downloaded from www.src.com or purchased with the latest graphical user interface (GUI) from the model developer. The sequence of model processors listed in Table 4 corresponds to the order in which the programs are typically run.

3. Meteorological data modeling (CALMET)

ADEQ will use the 2001-2003 CENRAP developed no-obs CALMET dataset for the screening analysis.* This decision was based on EPA Regions VI and VII written comments on the CENRAP BART Modeling Guidelines (Tesche, et al, 2005) which state,

> "Normally, in accordance with Section 8.3.1.2 (d) of the Guideline on Air Quality Models, the EPA would require that observations be incorporated in conjunction with prognostic meteorological data. While the idea of use of prognostic data alone holds promise, it is our opinion that this option requires further evaluation to insure that this approach does not bias CALPUFF towards underestimation (Guideline on Air Quality Models, Section 3.2.2 (d)(iv)). While we have significant concern regarding the use of the CALMET fields as they have been developed under the procedures documented in this protocol, we would consider the use of the CALMET meteorological fields provided the screening methodology described in Section 6.1 of the protocol is strictly adhered to. In this case, we feel that the use of the maximum visibility impact rather than the 98th percentile value is conservative in its application, and would overcome concerns of a potential bias towards underprediction [sic] of the "no-observation" mode. Under these circumstances, we would consider the use of the CALMET fields acceptable for the CALPUFF screening procedure." (EPA, 2005)

As stated in Section V. BART Air Quality Modeling Approach, ADEQ will use the **maximum** impact instead of the 98th percentile to determine if a source has an impact on visibility in a Class I.

However, subject-to-BART facilities have the option of using the CENRAP CALMET processed data or incorporating observational meteorological data into the aforementioned CALMET data. If a subject-to-BART facility opts to use the CENRAP CALMET processed data, then the facility will be required to use the maximum impact instead of the 98th percentile (8th day). If a subject-to-BART facility decides they would rather use the 98th percentile, then the facility will be required to incorporate observational data and provide a protocol as well as a performance evaluation which will need to be approved by ADEQ, EPA, and the FLMs.

Appendix F contains the detailed information on all CALMET setting that was used to develop the post-processed no-obs data fields.

4. Dispersion modeling (CALPUFF)

The CALMET output is used as input to the CALPUFF model, which simulates the effects of the meteorological conditions on the transport and dispersion of pollutants from an individual source. In general, ADEQ proposes to use the recommended default options in the CALPUFF model. There are some deviations, which are discussed below. Table 5 indicates the species that will be modeled and/or emitted in the no-obs and refined BART analyses.

Table 5 Species modeled in BART screening analyses

Species	Modeled	Emitted	Dry Deposited
SO_2	Yes	Yes	Computed-gas
SO_4^{-2}	Yes	No	Computed-particle
NO_x	Yes	Yes	Computed-gas
HNO_3	Yes	No	Computed-gas
NO_3^-	Yes	No	Computed-particle
PM-fine*	Yes	Yes	Computed-particle
PM_{10}*	Yes	Yes	Computed-particle

*Please refer to Section VI subsection B for a detailed discussion on PM-fine and PM_{10}.

<u>Emissions Speciation:</u> ADEQ does not intend to model sulfate (SO_4^{-2}), nitrate (NO_3^-), elemental carbon (EC), and secondary organic aerosols (SOA) during the screening analyses. However, ADEQ recognizes the impact EC and SOA have on visibility. For instance, the light extinction (β_{ext}) coefficient for EC is 10 and for SOA it is 4. Currently, data are quite limited on appropriate speciation of organic/inorganic and filterable/condensable emissions by source category. Although there are speciation profiles available for gas- and oil-fired combustion turbines and coal combustion processes, currently there are no detailed profiles for the full range of BART-eligible sources. Thus, in the case of a subject-to-BART source where the PM profile for SO42-, EC, and SOA are known, ADEQ recommends the aforementioned species be modeled as separate species in CALPUFF in the post-control modeling analysis.

<u>Condensable Emissions</u>: According to Tesche, et al (p 6-5 2005), “condensable emissions are considered primary fine particulate.” ADEQ is aware of the inability to measure $PM_{2.5}$ emissions. Thus, BART-eligible facilities will be most likely use AP-42 emission factors to develop the “actual” highest average 24-hr emission rate for this pollutant. In the development of this emission rate, ADEQ will require these facilities to use the AP-42 emission factors for condensable $PM_{2.5}$. For sources where AP-42 factors are not available, assumptions for partitioning need to be resolved with ADEQ.

<u>Size Classification of Primary PM Emissions</u>: Particle size parameters are entered in the CALPUFF input file for dry deposition of particles. There are default values for “aerosol” species (i.e., SO_4^{-2}, NO_3^-, and $PM_{2.5}$). The default value for each of these species is 0.48 μm geometric mass mean diameter and 2.0 μm geometric standard deviation. The main sources of these particles are fuel combustion. A way to account for this, without including EC and SOA in the modeling, is to use particle speciation in the post-processing step. This is discussed below in the CALPOST section.

As stated in a previous section, all PM_{10} emissions will be modeled as $PM_{2.5}$ for the no-obs model simulations (Tesche, et al, 2005).

<u>Background Ozone concentrations:</u> Ozone (O_3) can be input to CALPUFF as hourly or monthly background values. Hourly values of ozone concentrations were obtained from two rural monitoring sites in Arkansas: Deer, Newton County monitoring site and Eagle Mountain, Montgomery County monitoring site. The hourly ozone concentrations were adjusted for the time differences between the post-processed prognostic meteorological

file (0 GMT) and the collection time of the ozone (LST). Also, the concentrations were adjusted from parts per million (ppm) to parts per billion (ppb). These hourly ozone values will be used in this modeling.

<u>Background Ammonia concentrations:</u> Background ammonia concentration is assumed to be temporally and spatially invariant and will be fixed at 3 ppb across the entire domain for all months. It may be possible to derive NH_3 concentrations from regional modeling outputs that CENRAP is currently developing. At this time these NH_3 values are not available in a model ready form.

<u>Receptors:</u> Receptors are locations where model results are calculated and provided in the CALPUFF output files. Receptor locations were derived from the National Park Service's Class I area receptor database at http://www2.nature.nps.gov/air/maps/receptors/index.cfm. Only these discrete NPS receptors will be modeled in CALPUFF. The discrete receptors are necessary for calculating visibility impacts in the nine selected Class I areas that will be evaluated by ADEQ. All the discrete receptors will be placed with enough density that the highest visibility impacts should be evident. The NPS provides receptors in all the Class I areas on a 1 km basis. These receptors will be kept at the 1 km spacing for the BART modeling, and all receptors will be retained. NPS also provides a conversion program to convert the coordinates of the receptors from latitude/longitude (lat/long) to Lambert Conformal Conical (LCC). ADEQ used this conversion program to convert the receptors located in the five Class I areas it is assessing from lat/long to LCC.

<u>Outputs:</u> The CALPUFF modeling results will be displayed in units of micrograms per cubic meter ($\mu g/m^3$). In order to determine visibility impacts, the CALPUFF outputs must be post-processed.

Detailed information on all CALPUFF setting to be used in this screening analysis is located in Appendix G.

5. Post-processing (POSTUTIL/CALPOST)

Hourly concentration outputs from CALPUFF are processed through POSTUTIL and CALPOST to determine visibility conditions. Specifically, POSTUTIL takes the concentration file output from CALPUFF and recalculates the nitric acid and nitrate partition based on total available sulfate and ammonia. The ammonia-limiting method (ALM) in CALPUFF repartitions nitric acid and nitrate on a receptor-by-receptor and hour-by-hour basis to account for the models systematic over-prediction due to overlapping puffs. For both screening applications, the parameter MNIRATE=1 is set in POSTUTIL to implement this approximate correction in its simplest form. The background ammonia concentration that was obtained from CENRAP's regional modeling effort will be used to maintain regional consistency in the CENRAP region. CALPOST uses the concentration file processed through POSTUTIL, along with relative humidity (RH) data, to perform visibility calculations. For the BART analysis, the only modeling results out of the CALPUFF modeling system of interest are the visibility impacts.

Please see Appendix H and I for detailed settings for POSTUTIL and CALPOST.

Light extinction: Light extinction must be computed in order to calculate visibility. CALPOST has seven methods for computing light extinction. This BART screening analysis will use Method 6, which computes extinction from speciated particulate matter with monthly Class I area-specific relative humidity adjustment factors, and is implied by the BART guidance. Relative humidity (RH) is an important factor in determining light extinction (and therefore visibility) because SO_4^{-2} and NO_3^- aerosols, which absorb moisture from the air, have greater extinction efficiencies with greater RH. All BART analyses will apply relative humidity correction factors ($f_{(RH)}$s) to SO_4^{-2} and NO_3^- concentrations outputs from CALPUFF, which were obtained from EPA's "Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule (EPA, 2003). The $f_{(RH)}$ values for the Class I areas that will be assessed are provided in Table 5.

Table 6 EPA recommended monthly averaged $f_{(RH)}$ for the five Class I areas ADEQ is assessing (EPA, 2003)

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek	3.4	3.1	2.9	3.0	3.6	3.6	3.4	3.4	3.6	3.5	3.4	3.5
Hercules-Glades	3.2	2.9	2.7	2.7	3.3	3.3	3.3	3.3	3.4	3.1	3.1	3.3
Mingo	3.3	3.0	2.8	2.6	3.0	3.2	3.3	3.5	3.5	3.1	3.1	3.3
Sipsey	3.3	3.0	2.8	2.7	3.1	3.4	3.5	3.5	3.5	3.3	3.1	3.3
Upper Buffalo	3.3	3.0	2.7	2.8	3.4	3.4	3.4	3.4	3.6	3.3	3.2	3.3

The $PM_{2.5}$ concentrations are considered part of the dry light extinction equation and do not have a humidity adjustment factor. The light extinction equation is the sum of the wet SO_4^{-2} and NO_3^- and dry components $PM_{2.5}$ plus Rayleigh scattering (β_{Ray}), which is 10 inverse megameters (Mm^{-1}).

To account for sources modeled with a known PM speciation profile for EC, SOA, and SO_4, an adjustment to the extinction coefficient for the PM components will be made in CALPOST. ADEQ intends to follow the method outlined in the FLM CALPUFF Reviewer's Guide (Gebhart, 2005) which is located in Appendix K.

6. Measuring visibility impacts

The recommended procedure for quantifying visibility impacts can be found in Chapter 3 of the CENRAP BART Modeling Guidelines (Tesche, et al, 2005) which is located in Appendix J. The key point is that the light extinction coefficient (β_{ext}) can be calculated from the IMPROVE equation as:

$$\beta_{ext} = 3\,f_{(RH)}\,[(NH_4)_2SO_4] + 3\,f_{(RH)}\,[NH_4NO_3] + 4[OC] + 1[Soil] +$$

$$+ 0.6[Coarse\ Mass] + 10[EC] + \beta_{Ray}$$

The monthly site-specific $f(\mathrm{RH})$ values were obtained for the five Class I Area ADEQ is assessing from Table A-3 in the EPA (2003) guidance document. Then, the haze index (HI), in dv, is calculated in terms of the extinction coefficient via:

$$\mathrm{HI} = 10 \ln (\beta_{ext}/10)$$

The change in visibility (measured in terms of Δ dv) is then compared against background conditions. The Δ dv value is calculated from the source's contribution to extinction, β_{source}, and background extinction, $\beta_{background}$, as follows:

$$\Delta \mathrm{dv} = 10 \ln (\{\beta_{background} + \beta_{source}\} / \beta_{background})$$

If the Δ dv value is greater than or equal to 0.5 dv, the source is said to contribute to visibility impairment and is thus subject-to-BART controls. If not, it is BART-exempt.

The annual average natural levels of aerosol components at each Class I area being evaluated by ADEQ are shown in Table 7. Natural conditions by component in Table 6 are based on whether the Class I area is in the eastern or the western part of the United States. In this BART analysis, all Class I areas are located in the East. The source of this data is from EPA's Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (EPA, 2003).

Table 7 Average annual natural levels of aerosol components ($\mu g/m^3$) (EPA, 2003)

Class I Area	Region	SO_4	NO_3	OC	EC	Soil	Coarse Mass
Caney Creek	East	0.23	0.10	1.40	0.02	0.50	3.00
Hercules-Glades	East	0.23	0.10	1.40	0.02	0.50	3.00
Mingo	East	0.23	0.10	1.40	0.02	0.50	3.00
Sipsey	East	0.12	0.10	0.47	0.02	0.50	3.00
Upper Buffalo	East	0.23	0.10	1.40	0.02	0.50	3.00

As stated in section V, in a cooperative agreement with EPA Regions VI and VII and FLMs, CENRAP guidance deviates from use of the 98th percentile impact. The CALMET datasets as described in this protocol were processed with the no-obs options (i.e., surface observations were not used in the CALMET wind field interpolation). Aware that exercising CALMET with no-obs may lead in some applications to potentially less conservatism in the CALPUFF visibility results compared with the use of CALMET with observations, CENRAP has agreed to EPA's recommendation that the **maximum** visibility impact, rather than the 98th percentile value, should be used for the no-obs screening analysis using the CENRAP-developed CALMET datasets.

If the no-obs screening analysis results indicate a BART-eligible facility's maximum Δ dv on a Class I area is less that 0.5 dv, then they will be considered exempt from BART and will be notified by ADEQ of their status. However, if the maximum Δ dv is equal to or greater than 0.5 dv, the source will be considered to be subject-to-BART. ADEQ will notify these subject-to-BART facilities.

VIII. Change in Visibility Due to BART Controls

Once a facility is determined to be subject-to-BART, this facility must perform an engineering analysis and a post-control modeling analysis using CALPUFF. This modeling analysis must be compared to the pre-control modeling results. Please note that this will be a source specific (i.e. emitting unit specific) and pollutant specific modeling analysis using CALPUFF. If a subject-to-BART facility opts to use the 98th percentile rather than the maximum impact, the subject-to-BART facility will be required to be incorporate observational data with the post processed CALMET prognostic meteorological data. Also these facilities will be required to submit their meteorological modeling protocol, model performance evaluation, and CALPUFF modeling protocol to ADEQ, EPA Region VI, and FLMs for approval. However, if the subject-to-BART facility opts to use the maximum impact rather than the 98th percentile, these facilities may use the post-processed CALMET MM5 data.

Additionally, one control measure that a source may opt to use is to revise their Title V permit to provide for synthetic minor limits so that it falls under the BART emission cap. That permit modification must be done prior to the State going to public hearing on its RH SIP. The limits must be in place for as long as the RH SIP is applicable or for as long as the source is operational. However, the source will still need to do a post-control CALPUFF modeling analysis to determine the amount of emissions it needs to reduce for visibility improvement. (Note: ADEQ **strongly** recommends that all subject-to-BART facilities work closely with ADEQ in their engineering analyses.) Also, after all of the post-control results are submitted to and approved by ADEQ, these results will then be inputted into either CAMx or CMAQ for a cumulative model run. If the control measures proposed by the BART facilities still impact a Class I area, the BART facilities will need to implement additional control. Please note that all post-modeling results are due to ADEQ no later than October 23, 2006.

IX. References

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U.S. EPA, Regions VI & VII (2005). BART Protocol Comments.

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Appendix A. Proposed Time-line

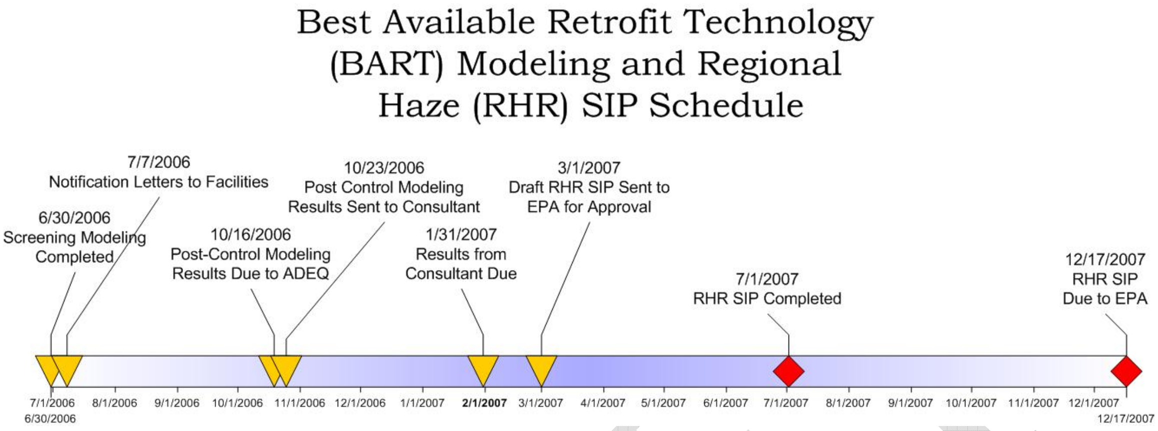


Figure A-1 ADEQ's proposed time-line to meet the RH SIP deadline of December 17, 2007 as set forth by EPA in its Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determination (40 CFR Part 51, p 39156)

Appendix B. Map of receptors

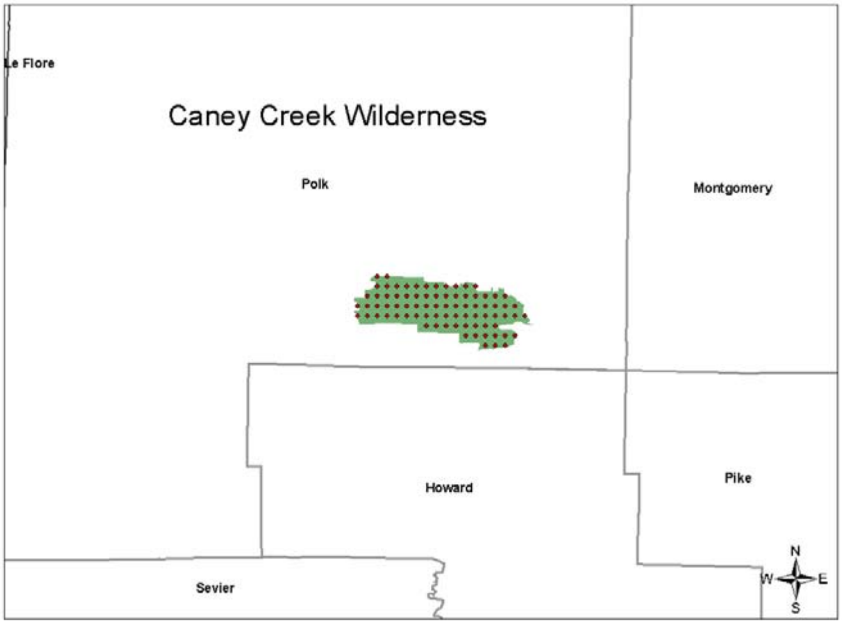


Figure B-1 Receptors located in Caney Creek Wilderness Area, Arkansas

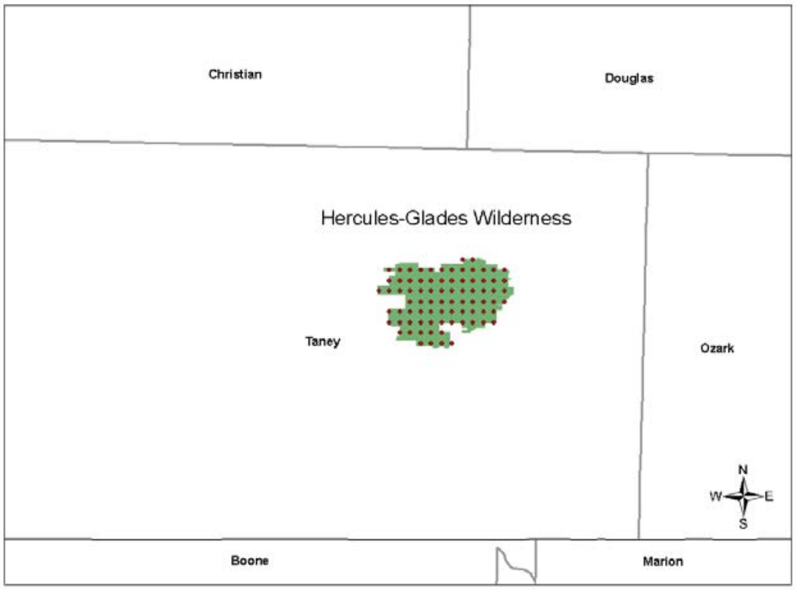


Figure B-2 Receptors located in Hercules-Glade Wilderness Area, Missouri

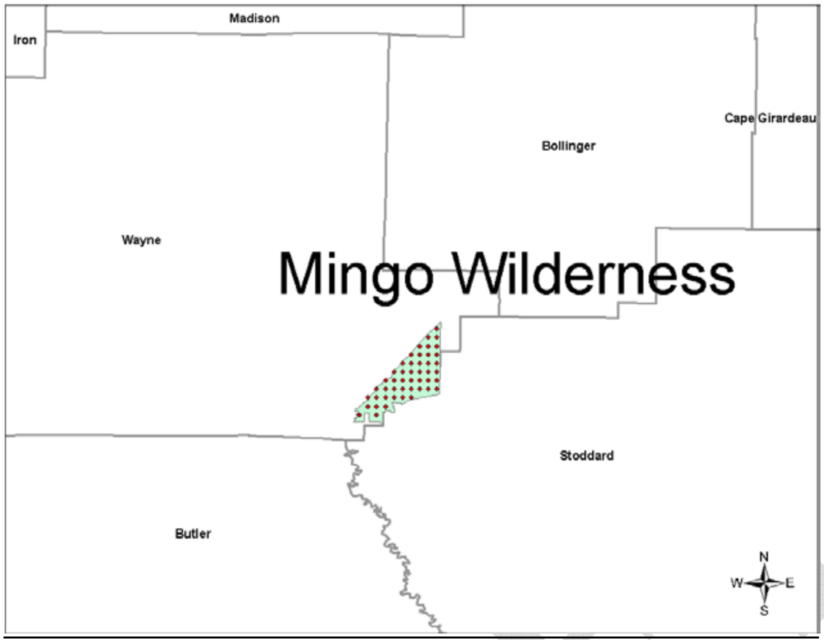


Figure B-3 Receptors located in Mingo Wilderness Area, Missouri

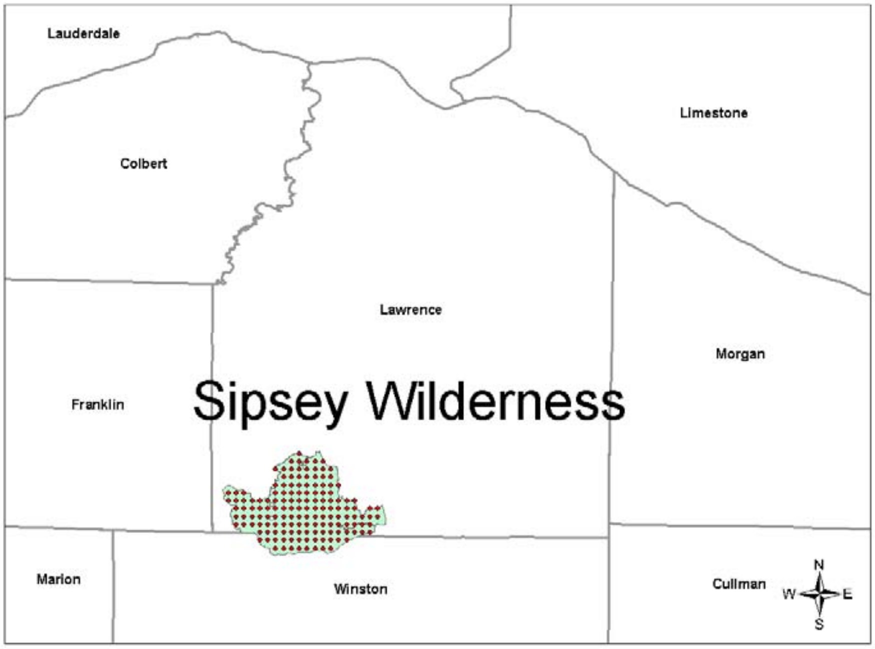


Figure B-4 Receptors located in Sipsey Wilderness, Alabama

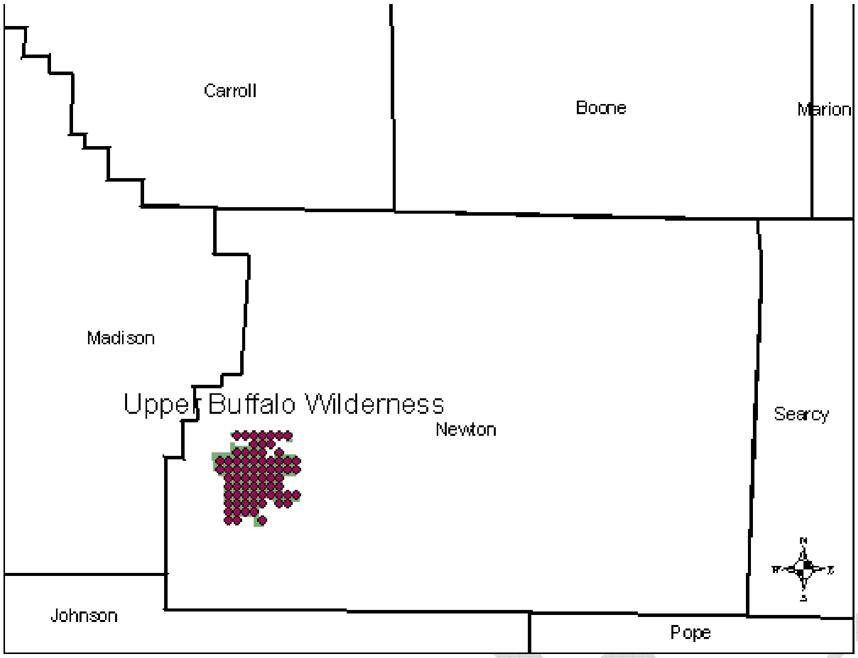


Figure B-4 Receptors located in Upper Buffalo Wilderness Area, Arkansas

Appendix C. BART-Eligible Sources' Stack Parameters, Base Elevation at Ground Level, and Stack Coordinates

Table C-1 BART-eligible sources' stack parameters

STATIONARY SOURCE NAME/LOCATION	**Emission Unit ID**	**Stack Height Meters**	**Stack Diameter Meters**	**Exit Velocity m/sec**	**Temperature ^{o}K**
Albermarle-South Plant / Magnolia	SR-01	57.9	0.814	15.24	922
Albermarle-South Plant / Magnolia	BH-01	6.4	2.591	9.14	505
Albermarle-South Plant / Magnolia	BH-02	6.4	2.591	9.14	505
American Elect. Power (SWEPCO) / Gentry	SN-01	164.6	6.096	34.14	408
AR Elect. Coop - Bailey Plant / Augusta	SN-01	50.9	3.000	28.04	444
AR Elect. Coop - McClellan Plant / Camden	SN-01	48.8	3.301	28.04	444
Big River Industries / W. Memphis	SN-01	30.5	1.524	21.88	330
Delta Natural Kraft / Pine Bluff	SN-02	50.3	2.134	13.29	348
Domtar, Inc. / Ashdown	SN-03	66.1	1.890	26.76	522
Domtar, Inc. / Ashdown	SN-05	71.6	3.659	11.92	325
Eastman Chemical / Batesville	6M01-01	61.0	2.743	9.45	422
El Dorado Chemical / El Dorado	SN-08	22.9	1.219	33.53	505
El Dorado Chemical / El Dorado	SN-09	22.9	1.219	32.00	500
El Dorado Chemical / El Dorado	SN-10	23.8	0.152	23.77	313
Entergy - Lake Catherine / Jones Mill	SN-03	59.4	5.182	3.08	396
Entergy - Ritchie Plant / Helena	SN-02	71.9	3.658	28.62	390
Entergy - White Bluff / Redfield	SN-01	304.8	7.833	27.43	434
Entergy - White Bluff / Redfield	SN-02	304.8	7.833	27.43	434
Entergy - White Bluff / Redfield	SN-05	4.6	0.914	19.81	519
Georgia-Pacific Paper / Crossett	SN-22	53.3	3.658	10.45	341
Great Lakes Chemical / El Dorado	SN-302A	9.1	0.762	40.54	555
Green Bay Packaging / Morrilton	SN-05A	30.8	1.798	25.60	456
Lion Oil / El Dorado	SN-809	61.0	1.753	9.75	533
Potlatch Corp. / McGehee	SN-04	89.6	2.743	14.78	444

Table C-2 BART-Eligible Emission Units' Base Elevation and Lambert Conformal Conical (LCC) Coordinates

STATIONARY SOURCE NAME/LOCATION (BART File Name)	**Emission UNIT ID**	**Base Elevation, meters (m)**	**X Easting LCC x**	**Y Northing LCC y**
Albermarle-South Plant / Magnolia	SR-01	86.9	352.81836	-747.03381
Albermarle-South Plant / Magnolia	BH-01	88.4	352.67618	-746.98114
Albermarle-South Plant / Magnolia	BH-02	88.4	352.65801	-746.98190
American Elect. Power (SWEPCO) / Gentry	SN-01	349.9	221.58128	-410.39077
Ark. Elect. Coop - Bailey Plant / Augusta	SN-01	61.3	510.86643	-507.71488
Ark. Elect. Coop - McClellan Plant / Camden	SN-01	33.5	390.21870	-702.15534
Big River Industries (General Shale)/ W. Memphis	SN-01	60.0	609.12652	-517.70639
Delta Natural Kraft / Pine Bluff	SN-02	66.4	457.00824	-621.20692
Domtar, Inc. / Ashdown	SN-03	97.5	267.47491	-698.66686
Domtar, Inc. / Ashdown	SN-05	97.5	267.48245	-698.74355
Eastman Chemical / Batesville	6M01-01	82.3	493.14724	-458.02938
El Dorado Chemical / El Dorado	SN-08	63.1	401.11728	-734.65321
El Dorado Chemical / El Dorado	SN-09	63.1	401.13533	-734.65236
El Dorado Chemical / El Dorado	SN-10	62.2	401.19594	-734.67412
Entergy - Lake Catherine / Jones Mill	SN-03	100.0	375.45658	-606.40861
Entergy - Ritchie Plant / Helena	SN-02	54.9	586.25363	-591.07129
Entergy - White Bluff / Redfield	SN-01	94.2	446.73457	-625.11197
Entergy - White Bluff / Redfield	SN-02	94.2	445.61252	-604.15523
Entergy - White Bluff / Redfield	SN-05	94.2	445.61539	-604.25671
Georgia-Pacific Paper / Crossett	SN-22	46.0	469.03486	-745.02133
Green Bay Packaging / Morrilton	SN-05A	98.5	387.29077	-532.44265
Lion Oil / El Dorado	SN-809	75.6	403.01817	-741.82948
Potlatch Corp. / McGehee	SN-04	43.9	533.13136	-678.59798

Appendix D. BART-Eligible Emission Rates used for the No-Obs Modeling Run

Table D-1 BART-eligible units' highest 24-hour actual emission rates for SO_2, NO_x, PM_{10}^* and $PM_{2.5}$ in grams per second (g/sec)

BART-Eligible Facilities/ Locations	Emission Unit ID Number	Highest 24-Hour Actual Emission Rates (g/sec)			
		SO_2	NO_x	PM_{10}	$PM_{2.5}$
Albermarle-South Plant / Magnolia	SR-01	48.126	0.076	0.000	0.009
Albermarle-South Plant / Magnolia	BH-01	0.353	2.075	0.000	0.136
Albermarle-South Plant / Magnolia	BH-02	0.535	2.578	0.000	0.128
American Elect. Power (SWEPCO) / Gentry	SN-01	595.781	245.066	21.725	5.531
AR Elect. Coop - Bailey Plant / Augusta	SN-01	299.344	36.933	21.729	21.729
AR Elect. Coop - McClellan Plant / Camden	SN-01	346.189	47.124	28.764	28.764
Big River Industries/ W. Memphis	SN-01	0.000	8.589	0.000	7.076
Delta Natural Kraft / Pine Bluff	SN-02	0.239	1.701	1.058	0.529
Domtar, Inc. / Ashdown	SN-03	0.774	22.632	0.000	21.354
Domtar, Inc. / Ashdown	SN-05	70.175	52.008	0.000	7.881
Eastman Chemical / Batesville	6M01-01	54.046	11.045	0.290	0.217
El Dorado Chemical / El Dorado	SN-08	0.000	20.060	0.000	0.000
El Dorado Chemical / El Dorado	SN-09	0.000	15.645	0.000	0.000
El Dorado Chemical / El Dorado	SN-10	0.000	0.415	0.000	0.000
Entergy - Lake Catherine / Jones Mill	SN-03	0.420	309.535	0.365	0.246
Entergy - Ritchie Plant / Helena	SN-02	0.105	17.640	0.997	0.997
Entergy - White Bluff / Redfield	SN-01	978.164	550.821	15.592	11.802
Entergy - White Bluff / Redfield	SN-02	985.933	596.075	16.653	12.915
Entergy - White Bluff / Redfield	SN-05	4.095	3.811	0.365	0.246
Georgia-Pacific Paper / Crossett	SN-22	77.275	182.677	0.000	9.310
Green Bay Packaging / Morrilton	SN-05A	4.934	8.771	0.000	1.165
Lion Oil / El Dorado	SN-809	23.142	5.980	0.000	7.696
Potlatch Corp. / McGehee	SN-04	6.942	10.533`	2.752	2.752

Appendix E. Chapter 5 of the CENRAP BART Modeling Guidelines (Tesche, et al, 2005)

5.0 DATA BASES FOR CALPUFF MODELING

To support BART modeling by the states and source operators, both meteorological and aerometric data sets are required. Regional meteorological data sets generated by the CALMET model suitable for direct input to the CALPUFF modeling system have been developed and archived. These data sets cover calendar years 2001, 2002, and 2003 for three sub-regional grid domains shown in Figures 5-1 through 5-4. The procedures used in developing the CALMET data sets generally follow the IWAQM recommendations (EPA, 1998), except for a few notable refinements. *The processed CALMET files, in CALPUFF-ready input format, are available from CENRAP on hard disk drives to interested states and stakeholders.*

This chapter describes how these meteorological modeling sets were developed and evaluated. The basic CALMET model configuration used to generate the three years of CALPUFF-ready meteorology is described in detail so that users of this information have a clear understanding of the data sets and their applicability. In addition, for those states or source operators who elect to conduct more source-specific CALMET/CALPUFF modeling, the information in this chapter may be helpful in guiding specification of revised CALMET model inputs and generation of revised CALMET data sets.

Also included in Section 5 .2 is a discussion of routinely available air quality monitoring data sets available to the states and source operators in support of screening and source-specific BART modeling exercises.

5.1 Development of CALMET Meteorological Files

5.1.1 MM5 Data Sets

Alpine Geophysics developed a consistent set of CALMET regional meteorological modeling data sets for use by the CENRAP States, BART eligible sources within the region and others. These meteorological modeling data sets were constructed through the joint use of the CALMET processor and results from existing annual three-dimensional MM5 meteorological simulations. The specific annual prognostic model simulations available for CENRAP BART modeling included:

- 2001 MM5 data set at 36/12 km resolution developed for EPA by Alpine Geophysics (McNally and Tesche, 2002; McNally 2003);
- 2002 MM5 data set at 36 km resolution developed for CENRAP by Iowa DNR (Johnson, 2003a,b),

- 2003 MM5 data set at 36 km resolution developed for the Midwest RPO (Baker, 2005; Baker et al., 2004; Kembell-Cook et al., 2005)

Each of these studies included a performance evaluation of the MM5 generated data sets against surface meteorological observations and the results of these evaluations are contained in the reports or presentations cited above. While there exists a set of annual 12 km MM5 meteorology for 2002, this data set was developed by four independent CENRAP modeling centers and these data sets have not been concatenated into one master data base. More importantly, there has been no systematic, rigorous model performance evaluation performed on the CENRAP 2002 12 km MM5 data yet. Accordingly, until such time as the 2002 12 km data set has been evaluated and shown to be of comparable reliability as the aforementioned MM5 data sets, it's use is contraindicated.

5.1.2 CALMET Model Configuration

The CALMET modeling procedures used to construct meteorological inputs to CALPUFF for visibility screening of BART eligible sources generally follows the IWAQM recommendations (EPA, 1998), except as noted below.

CALMET Model Options. The CALMET model has a number of user-selected options, parameter settings, and 'switches' that must be defined prior to exercising the processing system. These options and settings are well-described in the CALMET User's Guide (Scire et al., 2000a) and in the CALMET input file to the executable code. Appendix A of this protocol summarizes the CALMET configurations used in developing the processed 6 km meteorological fields over the three CENRAP BART modeling domains. Also included in the tables in Appendix A are the default CALMET options and parameter settings recommended in the IWAQM Phase 2 Report (EPA, 1998).

CALMET Domain. Three slightly overlapping modeling domains were defined by CENRAP to support BART modeling. These domains are shown in Figures 5-1 through 5-4 and Table 5-1. The processors used to generate the domain, land use, and elevation data for the CALMET/CALPUFF system include TERREL, CTGPROC, and MAKEGEO, as described below.

- TERREL is the terrain pre-processor that averages terrain features to the modeling grid resolution; TERREL constructs the basic properties of the gridded domain and defines the coordinates upon which meteorological data are stored. Key parameters include specification of grid type, location, resolution and terrain elevation.

- CTGPROC computes the fractional land use for the modeling grid resolution. Land use characteristics for each grid cell are assigned using CTGPROC. The primary variable adjustment associated with CTGRPOC is selection of an appropriate land use database. Version 2.0 of the North American Land Cover Characteristics database is used.

- MAKEGEO is the final pre-processor that combines the terrain and land use data for input to CALMET. Generating the appropriate MAKEGEO.INP control file requires only minimal alteration of the default assignments. Key modifications include specifying domain attributes and ensuring input files are correctly referenced.

Terrain. CALMET requires both terrain height and land use/land cover for the application region. These are generated using the CALMET CTGPROC, TERREL and MAKEGEO processors. The terrain data were created using the TERREL (version 3.311, level 030709) processor and the Shuttle Radar Topography Mission (SRTM)-GTOPO 30 second (~1 km) resolution dataset.

Land Use. The landuse data set was created using the Composite Theme Grid CTGROC processor (version 2.42, level 030709) and the United States Geological Survey (USGS) Global Land Cover Characterization (GLCC) version 2.0 database. The GLCC database is available at 30 second (~1km) resolution. References for these and other modeling datasets can be found at www.src.com.

Vertical Layer Structure. The vertical layer structure for the CALMET/CALPUFF screening applications is more refined than the general suggestions of IWAQM. The CENRAP vertical structure was designed to reduce the need for vertical interpolation while simultaneously improving vertical resolution within the planetary boundary layer (PBL). Table 5-2 identifies the 11 layer interfaces required to define the 10 layer vertical CALMET grid structure. The top interface in the CALMET simulation is 4000 meters.

*Use of Observations***.** Based on considerable discussions with State and Federal managers and agency personnel, CENRAP has elected to use the No-Obs mode in CALMET for constructing the 6 km meteorological fields for CALPUFF screening exercises. The three annual MM5 simulations (2001, 2002, and 2003) will be used as the sole source for meteorological data within CALMET. Blending observational data with the MM5 data within CALMET (i.e., use of the “OBS” option is essentially a redundant use of the same data. Substantial improvement in the MM5 initialization data and in the use of four dimensional data assimilation (FDDA) has been achieved in recent years using observational data. The ETA analysis data used in initial and boundary conditions estimates as well as within the FDDA fields derive from 3-hourly, 40 km objective analysis fields computed using an extensive supply of observational data (National Weather Service surface and upper air data, GOES satellite precipitable water; VAD wind profiles from NEXRAD; ACARS aircraft temperature data; SSM/I oceanic surface winds; daily NESDIS snow cover and sea-ice analysis data; RAOB balloon drift; GOES and TOVS-1B radiance data; 2D-VAR SST from NCEP Ocean Modeling Branch; radar estimated rainfall; and surface rainfall). The complexity, resolution, and accuracy of the ETA data that is used to initialize and 'nudge' the MM5 forecasts is extensive indeed. Particularly at the 12-36 km horizontal grid scales over the flat to modestly rolling topography of the CENRAP domain, there is no need to introduce local meteorological observations in order to retrieve local terrain effects, for example. Thus, mesoscale wind patterns are likely to be adequately characterized by the MM5 simulations.

Many observations, especially surface observations, reflect local conditions on a scale smaller than the 6 km CENRAP CALMET fields. The introduction of the local observations into the regional modeling domain may extend the influence of the observational data beyond its true representativeness and result in internally inconsistent flow features. In particular the time interpolation of the 12-hourly upper air sounding data may wash out structure in the MM5 fields that are appropriate to retain. Given that the CENRAP domain as a whole includes areas of moderately rolling terrain, coastal regions and relatively flat terrain, a single set of representative weights[1] that allows significant influence of the observations where appropriate, will involve a considerable effort and substantial testing. The internally consistent MM5 fields are considered likely to be appropriate for the regional simulations, and the incremental benefit of adding the observational data into the regional CALMET simulations is not considered worthwhile.

However, on the smaller domains likely to be considered in source-specific modeling (e.g., 1-4 km in scale) with the higher CALMET grid resolution and the smaller domain size, more control over the region of influence of the meteorological observations can be achieved. It is easier for the diagnostic model to allow the local flow observations to have appropriate influence in the vicinity of the observation, but allow terrain-adjusted flow to dominate away from the observations. Given that the fine scale source-specific domains will be used especially in irregular and/or meteorologically complex settings, the relatively coarser-scale MM5 simulations are less likely to be fully adequate, and the introduction observational data into CALMET is more likely to achieve improvements in the resulting meteorological fields.

<u>*Diagnostic Model Settings*</u>

A number of diagnostic model settings must be selected for CALMET to properly process representative diagnostic meteorological data sets. These are summarized in Appendix A, compared to the default CALMET settings, and discussed in the following:

---

[1] Weights are assigned in CALMET to control the 'blending' of observations and MM5 predictions.

> CALMET options dealing with radius of influence parameters (R1, R2, RMAX1, RMAX2, RMAX3), BIAS, ICALM parameters are not used in No-Observations mode;

> Gridded cloud data were inferred from the MM5 relative humidity fields (ICLOUD=3);

> Given that all state variables are MM5-derived (IPROG=14; ITPROG=2), surface layer winds were not extrapolated to the upper layers (IEXTRP = -1);

> The IWAQM recommendation for disabling the computation of kinematic effects in the wind field options and parameters was selected. This was selected in light of the very modest elevated terrain in the CENRAP domain, relative to the mountainous regions in the U.S. and Alps where the kinematic parameterizations were originally developed. Thus, the option for computing kinematic effects was disabled (IKINE = 0).

> The BIAS array was set to 0. in the CALMET control file because surface and upper air data were not used (NOOBS = 2);

> Because the MM5 wind fields supply CALMET with the initial guess fields to the diagnostic wind model (IWFCOD =1, IPROG = 14) and observational data are not reintroduced, the following variables were set to nominal values:

- The minimum distance for which extrapolation of surface winds should occur was set to -1 (RMIN2 = -1.).
- RMIN was left at the IWAQM recommendation of 0.1 km.
- RMAX1 and RMAX2 were each assigned a value of 30 km. RMAX3 was assigned a value of 50 km.
- R1 and R2 were each assigned the value of 1.0.
- ISURFT and IUPT were assigned placeholder values of 4 and 2, respectively.

> The radius of influence regarding terrain features is comparable to the resolution of the processed terrain data: 12 km.

> The radius of influence for temperature interpolation is set to 36 km (TRADKM), a value considered appropriate given the 6 km CALMET domain and 36/12 km MM5 domain.

> The beginning/ending land use categories for temperature interpolation over water are assigned category 55: (JWAT1 = JWAT2 = 55).

- SIGMAP was set to 50 km, while the IWAQM recommendation is 100 km, but with no supporting documentation. Because precipitation rates are explicitly incorporated from the MM5 data, a lower radius of influence was deemed appropriate.

- Diagnostic options: IWAQM default values were used (see Appendix A);

- TERRAD (terrain scale) is required for runs with diagnostic terrain adjustments (i.e., the 2003 simulations). Values of ~10-20 km were tested, and an appropriate value determined.

- Land use defining water: JWAT1 = 55, JWAT2 = 55 (large bodies of water). This feature allows the temperature field over large bodies of water such as the Gulf of Mexico and the Great lakes to be properly characterized by buoy observations.

- Mixing height averaging parameter (MNMDAV) were determined sensitivity tests. The purpose of the testing is to optimize the variable to allow spatial variability in the mixing height field, but without excessive noise.

Obviously, there are some instances where more advanced and/or recently developed procedures for constructing the CALMET fields have been used compared with the IWAQM (1998) guidance. For example, one agency expressed concern about the choice to employ prognostic model-derived gridded cloud cover data in CALMET (ICLOUD = 3). While this is admittedly a 'non-guideline' option, in our view it represents the best science option currently available. In particular, the EPA CAIR and CAMR rulemaking modeling and the CAMx/CMAQ modeling being performed by the RPOs for regional haze all utilize the gridded moisture fields in the MM5 model as a basis for estimating cloud. Presumably, if the method is suitable for such advanced visibility modeling, it is adequate for CALPUFF modeling. Of course, in the protocol negotiation, the States, source operators, and regulatory agencies have an opportunity to re-examine the CALMET diagnostic model settings used in creating the CENRAP gridded fields and modify them if warranted.

In summary, the development of the regional CALMET meteorological fields from MM5 data was conducted in No-Observations ("No-Obs") mode. CALMET's boundary layer modules were used to compute mixing heights, turbulence coefficients and other meteorological parameters required as input to CALPUFF.

5.1.3 MM5/CALMET Processing

Construction of the CALPUFF-ready meteorological fields entails a two-step process. First, the MM5 prognostic model output fields are extracted and processed for input to CALMET. This step entails running various extraction software routines followed by the CALMM5 code. Then, CALMET is exercised for the full three year period over each sub-regional CENRAP domain.

CALMM5. Previous applications of the prognostic Mesoscale Meteorological model version 5 (MM5) served as the source of the gridded meteorological fields for calendar years 2001, 2002, and 2003. The actual CALMM5 configuration entailed modification of a few user-specified variables. However, two setting are of primary importance:

> All vertical layers from MM5 were extracted, providing CALMET configuration flexibility, and

> Vertical velocity, relative humidity, cloud/rain fields, and ice/snow fields were extracted. (Graupel was extracted for 2001, the only year where the data were available in the MM5 datasets.)

CALMET. CALMET (v5.53a, lev 040716) was applied consistent with CENRAP's recommendation that the 6 km be generated using the 'No-Obs' option. The specific options used have been discussed above and are summarized in Appendix A.

5.1.4 Evaluation of the CALPUFF-Ready Meteorological Data Sets

In typical applications the adequacy of the CALMET fields is seldom evaluated using independent measurements. Often, only cursory visual examination of wind vector plots or time series is considered. This evaluation is important because the CALMET performance analysis gives direct insight into the adequacy of the model-processed fields on a subregional basis. It also serves as an independent quality assurance tool. Alpine's MAPS evaluation software to perform an independent evaluation of the processed CALMET data bases. MAPS was used in conjunction with the NCAR DS472 TDL data sets to evaluate the surface winds and temperatures for 2001-2003 across all three domains. Since only a small portion of the meteorological content of these data were ingested in the MM5 data assimilation routines (see Johnson, 2003a), these data sets are essentially an independent, quantitative means for evaluating the adequacy of the meteorological fields input to CALPUFF.

CALMET Evaluation Methodology

Several statistical measures were calculated as part of the CALMET meteorological evaluation using established procedures (e.g., Tesche et al., 1990; Emery et al., 2001). Additional plots and graphs are used to present these statistics on both hourly and daily time frames over the full annual cycle. For this study, evaluation measures were calculated for wind, temperature, and relative humidity because these parameters are the principal meteorological inputs to CALPUFF. The full set of CALMET evaluation statistics and graphical displays generated with the AG-MAPS software (McNally and Tesche,1994) are contained on a DVD available from CENRAP.

The statistics used to evaluate the meteorological fields for 2001-2003 are generated in both absolute terms (e.g., wind speed error in m/s), and relative terms (percent error) as is commonly done for air quality assessments. Obviously, a very different significance is associated with a given relative error for different meteorological parameters. For example, a 10% error for wind speed measured at 10 m/s is an absolute error of 1 m/s, a minor error. Yet a 10% error for temperature at 300 K is an absolute error of 30 K, a ridiculously large error. On the other hand, pollutant concentration errors of 10% at 1 ppb or 10 ppm carry practically the same significance.

Three key meteorological metrics include the bias, error, and index of agreement (IOA) for wind speed, temperature and relative humidity. These measures are defined as follows:

Bias (B): Calculated as the mean difference in prediction-observation pairings with valid data within a given analysis region and for a given time period (hourly or daily):

$$B = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left(P_j^i - O_j^i\right)$$

Error (E): Calculated as the mean *absolute* difference in prediction-observation pairings with valid data within a given analysis region and for a given time period

$$E = \frac{1}{IJ}\sum_{j=1}^{J}\sum_{i=1}^{I}\left|P_j^i - O_j^i\right|$$

(hourly or daily).

Note that the bias and gross error for winds are calculated from the predicted-observed residuals in speed and direction (not from vector components *u* and *v*). The direction error for a given prediction-observation pairing is limited to range from 0 to ±180°.

Index of Agreement (IOA): calculated following the approach of Willmont (1981). This metric condenses all the differences between model estimates and observations within a given analysis region and for a given time period (hourly and daily) into one statistical quantity. It is the ratio of the total RMSE to the sum of two differences – between each prediction and the observed mean, and each observation and the observed mean:

$$IOA = 1 \; - \left[\frac{IJ \cdot RMSE^2}{\sum_{j=1}^{J}\sum_{i=1}^{I}\left|P_j^i - M_o\right| + \left|O_j^i - M_o\right|}\right]$$

Viewed from another perspective, the index of agreement is a measure of the match between the departure of each prediction from the observed mean and the departure of each observation from the observed mean. Thus, the correspondence between predicted and observed values across the domain at a given time may be quantified in a single metric and displayed as a time series. The index of agreement has a theoretical range of 0 to 1, the latter score suggesting perfect agreement.

CALMET Evaluation Results

Table 5-5 summarizes the statistical measures, averaged over the month, for temperature, wind speed, and relative humidity for all three years. The CALMET evaluation DVD contains a full compilation of the statistical and graphical results. Figures 5-7 through 5-31 present a variety of graphical displays of processed and observed surface temperature, relative humidity, and wind across the three CENRAP subdomains for the three-year period 2001-2003. Figures 5-28 through 5-31 provide convenient summaries of the bias and error in the relative humidity, temperature, and wind speed fields across the continuous 36 month period by subdomain.

Thorough discussion of the performance findings is beyond the scope of these guidelines. However, a few key findings of the evaluation are worth noting here. From Table 5-5, the wind speed index of agreement, a general measure of correlation between measured and observed winds, is systematically greater than a value of 0.8 for virtually every month. These values are typically better than those generally achieved in urban- and regional-scale model applications for ozone SIPs. For example, the statistical benchmark for IOA suggested by Emery et al., (2001) is IOA > 0.6. Thus, the wind speed agreement for all three domains and all three years appears quite good relative to other MM5/RAMS model applications. From Figure 5-11, the wind speed root mean square error for the Central domain for 2002 is generally below 2.0 m/s, the performance goal for this parameter. From Figure 5-29 (as well as in Table 5-5), the temperature bias results for the 36 month are generally quite close to the ± 0.5 deg C performance goal. As shown in Figure 5-30 the temperature error results are slightly poorer than the 2 deg C performance goal for 2001 and 2003, but are below the 2.0 deg C threshold for 2002. Note that the benchmarks were developed not to provide a pass/fail standard to which all modeling results should be held, but rather to put the results into an historical context.

In summary, we find that:

- Relative Humidity
    - Bias over three-year period near zero all domains
    - For some months over- and under-prediction (up to 10% or more) is evident – no discernable trend
    - Errors typically diminish from 2001 through 2003, and are generally < 12% after 1st quarter of 2001.

- Surface Temperatures

  - Monthly averaged temperatures are systematically biased low (cooler) by 0.25 to 1.25 deg C.
  - The errors in monthly averaged temperatures typically range between 1.8 and 2.6 deg C
  - Average error over all months is about 2.2 deg C.

- Surface Wind Speeds
  - IOA typically between 0.8 0-0.9
  - Seasonally variable
  - Central subdomain gives best correlation

- Results from MM5/CALMET evaluation provide potentially useful information for diagnosing BART visibility modeling analyses

- MM5/CALMET fields exhibit good statistical agreement with observations, in part because observations figure prominently in the construction of the interpolated CALMET fields.

- MM5/CALMET fields for the three CENRAP subdomains are quite sufficient for use in CALPUFF modeling.

5.1.5 Meteorological Data Archive and Distribution

All models, scripts and CALMET data (excepting MM5 outputs) are available from CENRAP on appropriate external combination Firewire/USB drives.

5.2 Aerometric Monitoring Networks

Data from ambient monitoring networks for both gas-phase and aerosol species are available for use in CENRAP BART modeling analyses. Table 5-4 summarizes ambient monitoring networks. Data for 2002 have been compiled for all networks covering the CENRAP domain with the exception of the PAMS and PM Supersites. These data sets may be obtained from CENRAP. Figures 5-5 and 5-6 display the locations of monitoring sites in and near the CENRAP States.

Table 5-1. CENRAP Lambert Conic Conformal Modeling Domain Specifications (40.97 degree projection origin; 33 and 45 degree matching parallels).

Domain	Southwest Coordinate (km)	Number of X grid cells	Number of Y grid cells	Horizontal Resolution
CALMET				
South	-1008, -1620	306	246	6 km
Central	-1008, -864	388	234	6 km
North	-1008, 0	300	193	6 km

Table 5-2. Vertical Layer Structure in CALMET Fields. (Heights are in meters.)

LAYER NUMBER	LAYER HEIGHT	LAYER NUMBER	LAYER HEIGHT
0	0.	6	640.
1	20.	7	1200.
2	40.	8	2000.
3	80.	9	3000.
4	160.	10	4000.
5	320.		

Table 5-3. Meteorological Model File Sizes for CENRAP BART Modeling.

CALMET 6 km File Sizes, (Gbytes)				MM5 File Sizes, (Gbytes)		
Domain	Monthly	Annual	3 Years	Domain	Grid	3 years
North	4.6	55.2	165.6	2001	12 km	1370
Central	6.6	79.2	237.6	2002	36 km	430
South	6.0	72.0	216.0	2003	36 km	430
total	17.2	206.4	619.2	total		2230

Table 5-4. Statistical Evaluation of the CALMET Meteorological Fields for 2001-2003.

CALMET Model Evaluation Statistics for 2001.													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Mean
RH Bias (%)													
North	4.54	3.19	0.17	-14.55	-12.09	-4.35	-0.62	1.17	-2.07	-7.98	-6.62	-4.22	-3.62
Central	-2.60	-7.28	-11.38	-10.69	-8.62	-2.90	0.66	1.07	-1.44	-5.46	-6.16	-7.78	-5.21
South	-10.23	-11.53	-13.78	-4.24	-2.08	0.99	4.12	3.16	-0.12	-2.12	-3.44	-9.76	-4.09
RH Error (%)													
North	10.06	10.31	14.03	18.77	16.28	12.39	11.82	11.76	13.26	15.54	13.53	12.89	13.39
Central	13.32	15.86	17.45	17.05	14.50	11.67	11.52	11.32	12.26	15.52	14.79	14.95	14.18
South	16.22	18.37	18.17	13.26	12.15	11.51	12.09	12.40	11.82	14.85	14.73	16.19	14.31
Temp Bias (^{0}C)													
North	-1.63	-1.23	-1.23	-0.24	0.08	-0.29	-0.23	-0.54	-0.55	-0.09	-0.40	-1.27	-0.64
Central	-0.99	-0.65	-0.54	-0.16	0.13	-0.23	-0.43	-0.54	-0.36	-0.34	-0.30	-0.74	-0.43
South	-0.47	-0.42	0.03	-0.31	-0.33	-0.63	-0.99	-0.85	-0.52	-0.36	-0.19	-0.21	-0.44
Temp Error (^{0}C)													
North	3.10	2.88	2.54	2.49	2.44	2.43	2.42	2.49	2.58	2.48	2.89	2.55	2.61
Central	2.38	2.25	1.99	2.18	1.99	2.01	2.07	2.11	2.21	2.52	2.61	2.42	2.23
South	2.31	2.28	1.92	2.13	2.01	2.17	2.19	2.21	2.19	2.70	2.49	2.50	2.26
Wind Speed IOA													
North	0.79	0.83	0.83	0.87	0.86	0.85	0.81	0.84	0.84	0.82	0.81	0.79	0.83
Central	0.85	0.87	0.88	0.88	0.89	0.86	0.84	0.86	0.87	0.86	0.85	0.84	0.86
South	0.81	0.80	0.85	0.79	0.83	0.83	0.78	0.80	0.82	0.82	0.80	0.82	0.81

CALMET Model Evaluation Statistics for 2002.													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Mean
RH Bias (%)													
North	8.33	9.52	6.63	0.95	-2.42	1.25	2.43	1.60	0.57	0.47	4.47	7.73	3.46
Central	7.43	5.13	4.60	1.65	-1.02	1.52	2.50	1.88	-0.27	-1.40	-0.01	4.35	2.20
South	3.08	-1.19	2.53	2.32	1.26	1.98	2.51	2.62	-0.80	-2.42	-4.45	-1.03	0.53
RH Error (%)													
North	11.85	13.18	11.61	11.13	11.90	10.04	9.54	9.08	10.26	10.26	11.55	11.61	11.00
Central	12.21	12.43	11.26	10.58	10.72	9.89	9.55	9.54	10.22	10.25	11.42	11.26	10.78
South	11.24	11.76	10.34	8.95	9.30	9.49	9.46	9.61	9.68	9.33	11.63	10.95	10.14
Temp Bias (^{0}C)													
North	-0.70	-0.82	-0.96	-0.52	-0.25	-0.36	-0.53	-0.49	-0.44	-0.67	-0.76	-0.69	-0.60
Central	-0.57	-0.65	-0.79	-0.62	-0.41	-0.68	-0.81	-0.74	-0.49	-0.54	-0.55	-0.52	-0.61
South	-0.23	-0.13	-0.52	-0.61	-0.61	-0.94	-0.94	-1.07	-0.65	-0.47	0.04	-0.13	-0.52
Temp Error (^{0}C)													
North	2.15	2.07	2.04	1.89	1.86	1.83	1.86	1.80	1.95	1.78	1.99	2.15	1.95
Central	2.12	2.05	2.14	1.95	1.91	1.93	1.93	1.92	2.02	1.77	2.00	2.00	1.98
South	2.18	2.05	2.17	1.83	1.89	1.91	1.88	2.00	1.92	1.68	2.06	1.93	1.96
Wind Speed IOA													
North	0.82	0.84	0.86	0.88	0.86	0.85	0.85	0.83	0.85	0.85	0.81	0.78	0.84
Central	0.87	0.88	0.90	0.90	0.88	0.87	0.84	0.84	0.87	0.88	0.85	0.85	0.87
South	0.86	0.86	0.85	0.85	0.84	0.82	0.79	0.80	0.83	0.83	0.83	0.82	0.83

CALMET Model Evaluation Statistics for 2003.													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Mean
RH Bias (%)													
North	10.15	7.40	6.01	0.93	-3.76	-0.38	1.38	2.04	-1.66	-1.99	2.96	7.68	2.56
Central	6.94	4.76	4.15	0.42	-2.18	0.17	2.08	2.13	-2.05	-4.13	0.00	5.47	1.48
South	0.00	0.00	0.47	-1.10	-0.37	0.54	1.77	2.89	-3.31	-6.01	-3.66	-0.33	-0.76
RH Error (%)													
North	13.30	11.21	12.32	11.70	11.65	10.03	9.70	9.57	11.13	12.68	11.53	11.85	11.39
Central	12.77	10.95	11.61	11.18	10.33	9.91	9.49	9.50	10.70	12.69	12.10	12.43	11.14
South	11.18	10.00	9.85	10.17	9.20	9.54	8.90	9.91	10.21	12.12	12.15	12.39	10.47
Temp Bias (^{0}C)													
North	-1.24	-0.99	-0.63	-0.29	-0.11	-0.10	-0.22	-0.49	-0.34	0.29	-0.85	-1.34	-0.53
Central	-0.84	-0.80	-0.64	-0.47	-0.27	-0.36	-0.60	-0.66	-0.32	0.30	-0.54	-0.89	-0.51
South	-0.17	-0.27	-0.36	-0.43	-0.46	-0.62	-0.91	-0.98	-0.28	0.53	0.00	-0.03	-0.33
Temp Error (^{0}C)													
North	2.31	2.15	2.14	2.02	1.81	1.77	1.91	1.98	2.25	2.57	2.30	2.67	2.16
Central	2.14	2.03	2.15	2.13	1.80	1.81	1.96	1.99	2.16	2.54	2.31	2.45	2.12
South	2.10	1.90	2.00	2.08	1.84	1.81	1.88	2.06	1.94	2.40	2.28	2.48	2.06
Wind Speed IOA													
North	0.79	0.81	0.83	0.86	0.87	0.85	0.86	0.87	0.84	0.82	0.80	0.82	0.83
Central	0.85	0.88	0.87	0.89	0.90	0.87	0.87	0.86	0.87	0.87	0.86	0.86	0.87
South	0.83	0.83	0.85	0.83	0.85	0.81	0.83	0.82	0.85	0.84	0.82	0.82	0.83

Table 5-5. Overview of Ambient Data Monitoring Networks Covering the CENRAP Domain.

Monitoring Network	Chemical Species Measured	Sampling Period	Data Availability/Source
The Interagency Monitoring of Protected Visual Environments (IMPROVE)	Speciated PM25 and PM10 (see species mappings)	1 in 3 days; 24 hr average	http://vista.cira.colostate.edu/improve/Data/IMPROVE/improve_data.htm
Clean Air Status and Trends Network (CASTNET)	Speciated PM25, Ozone (see species mappings)	Approximately 1-week average	http://www.epa.gov/castnet/data.html
National Atmospheric Deposition Program (NADP)	Wet deposition (hydrogen (acidity as pH), sulfate, nitrate, ammonium, chloride, and base cations (such as calcium, magnesium, potassium and sodium)), Mercury	1-week average	http://nadp.sws.uiuc.edu/
Air Quality System (AQS) Aka Aerometric Information Retrieval System (AIRS)	CO, NO2, O3, SO2, PM25, PM10, Pb	Typically hourly average	http://www.epa.gov/air/data/
Speciation Trends Network (STN)	Speciated PM	24-hour average	http://www.epa.gov/ttn/amtic/amticpm.html
Southeastern Aerosol Research and Characterization (SEARCH) (Southeastern US only)	24-hr PM25 (FRM Mass, OC, BC, SO4, NO3, NH4, Elem.); 24-hr PM coarse (SO4, NO3, NH4, elements); Hourly PM2.5 (Mass, SO4, NO3, NH4, EC, TC); Hourly gases (O3, NO, NO2, NOy, HNO3, SO2, CO)	Hourly or 24-hour average, depending on parameter.	Electric Power Research Institute (EPRI), Southern Company, and other companies. http://www.atmospheric-research.com
EPA Particulate Matter Supersites (Includes St. Louis in the CENRAP region)	Speciated PM25		http://www.epa.gov/ttn/amtic/supersites.html
Photochemical Assessment Monitoring Stations (PAMS)	Varies for each of 4 station types.		http://www.epa.gov/ttn/amtic/pamsmain.html
National Park Service Gaseous Pollutant Monitoring Network	Acid deposition (Dry; SO4, NO3, HNO3, NH4, SO2), O3, meteorological data	Hourly	http://www2.nature.nps.gov/ard/gas/netdata1.htm

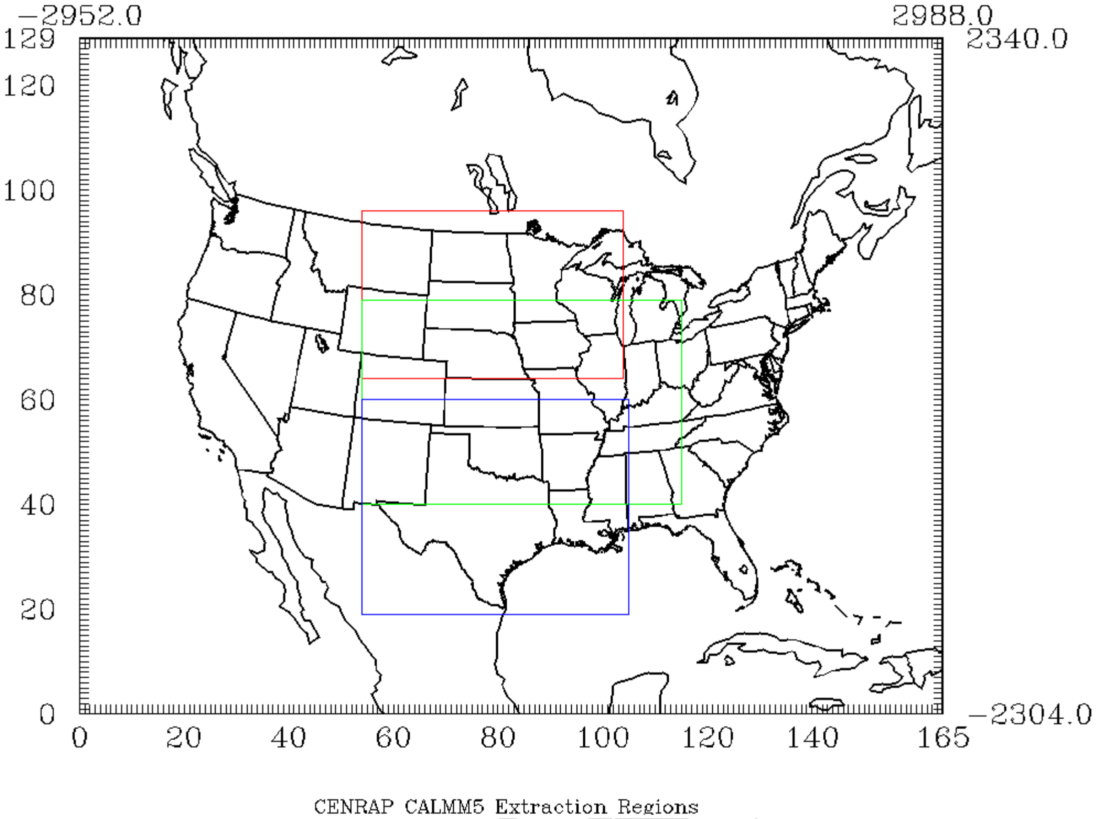


Figure 5-1. CENRAP North, Central, and South 6 km Meteorological Domains.

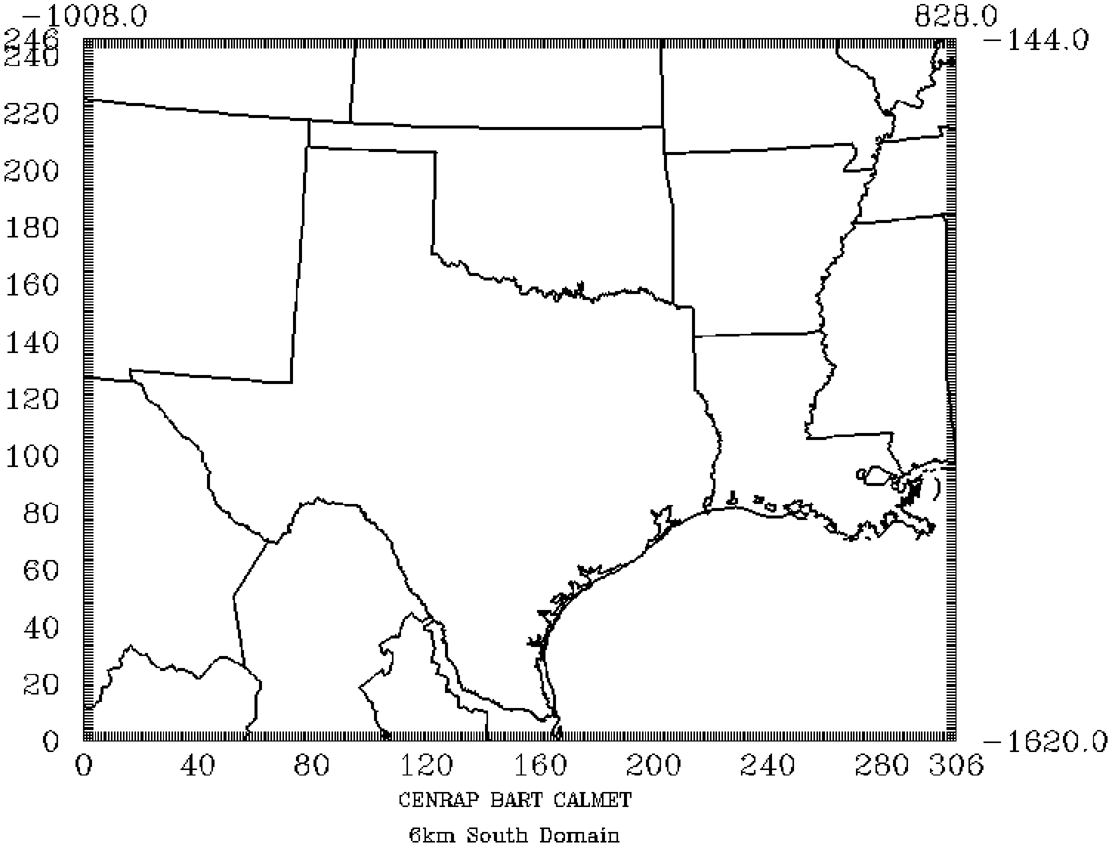


Figure 5-2. CENRAP South Domain.

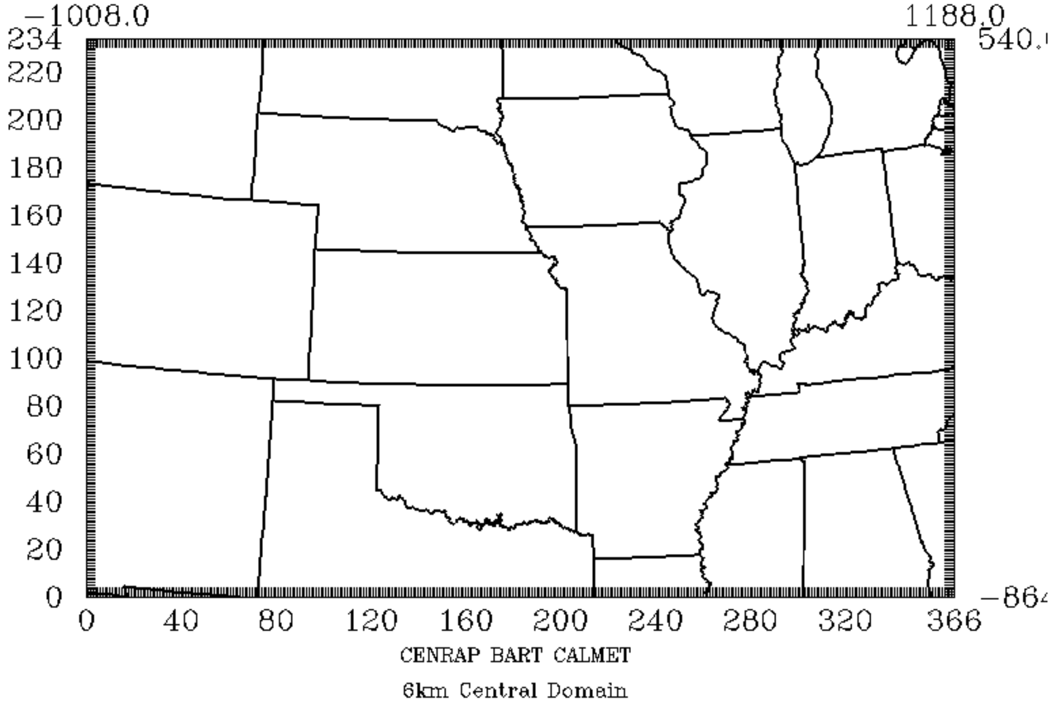


Figure 5-3. CENRAP Central Domain.

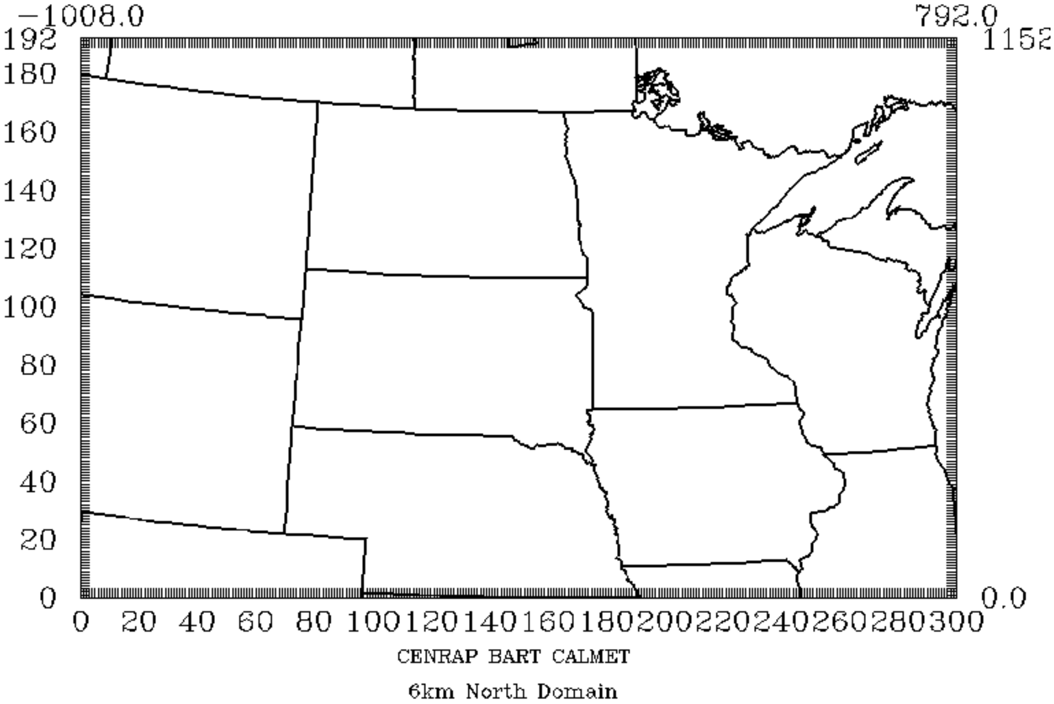


Figure 5-4. CENRAP North Domain.

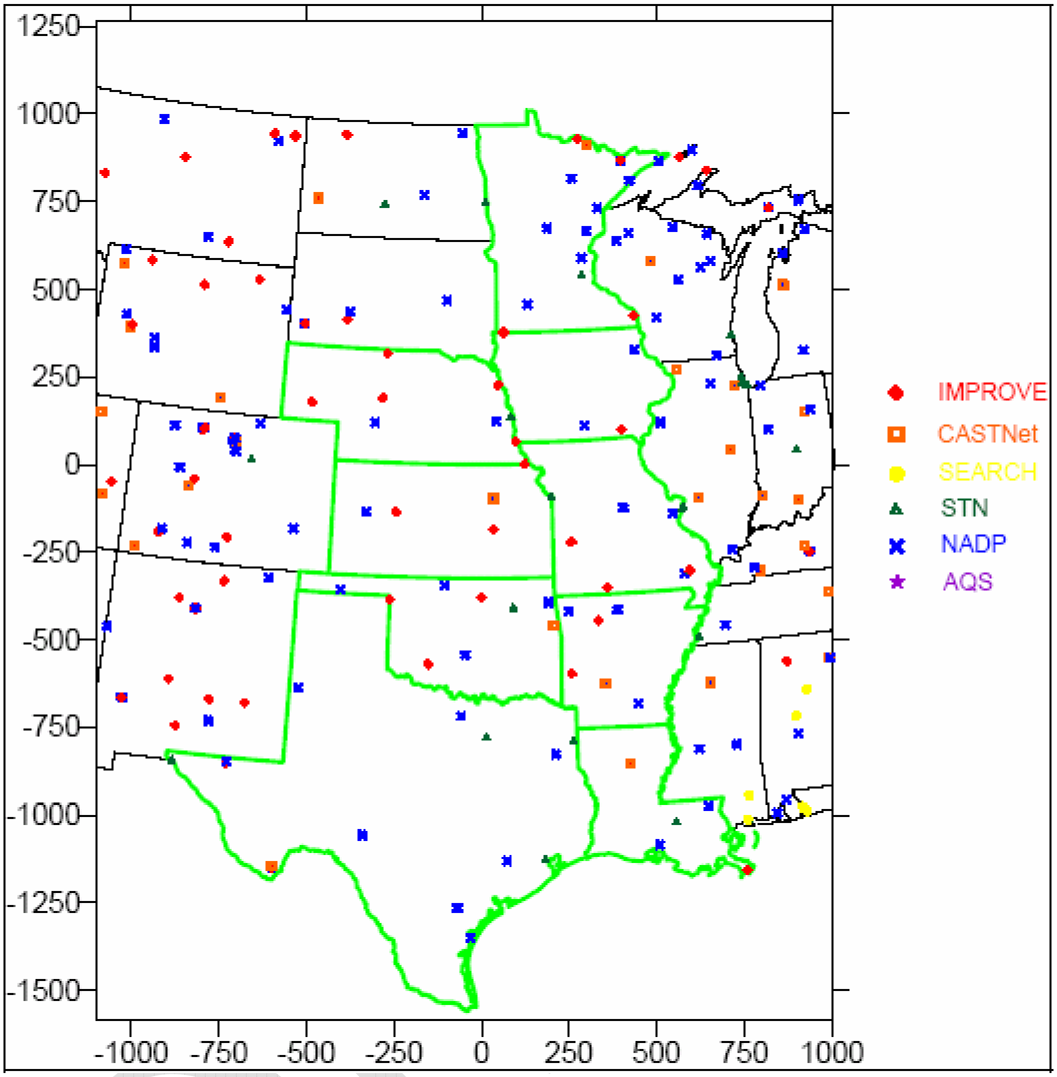


Figure 5-5. Locations of IMPROVE, CASTNet, SEARCH, STN and NADP Monitoring Sites in and Near the CENRAP States.

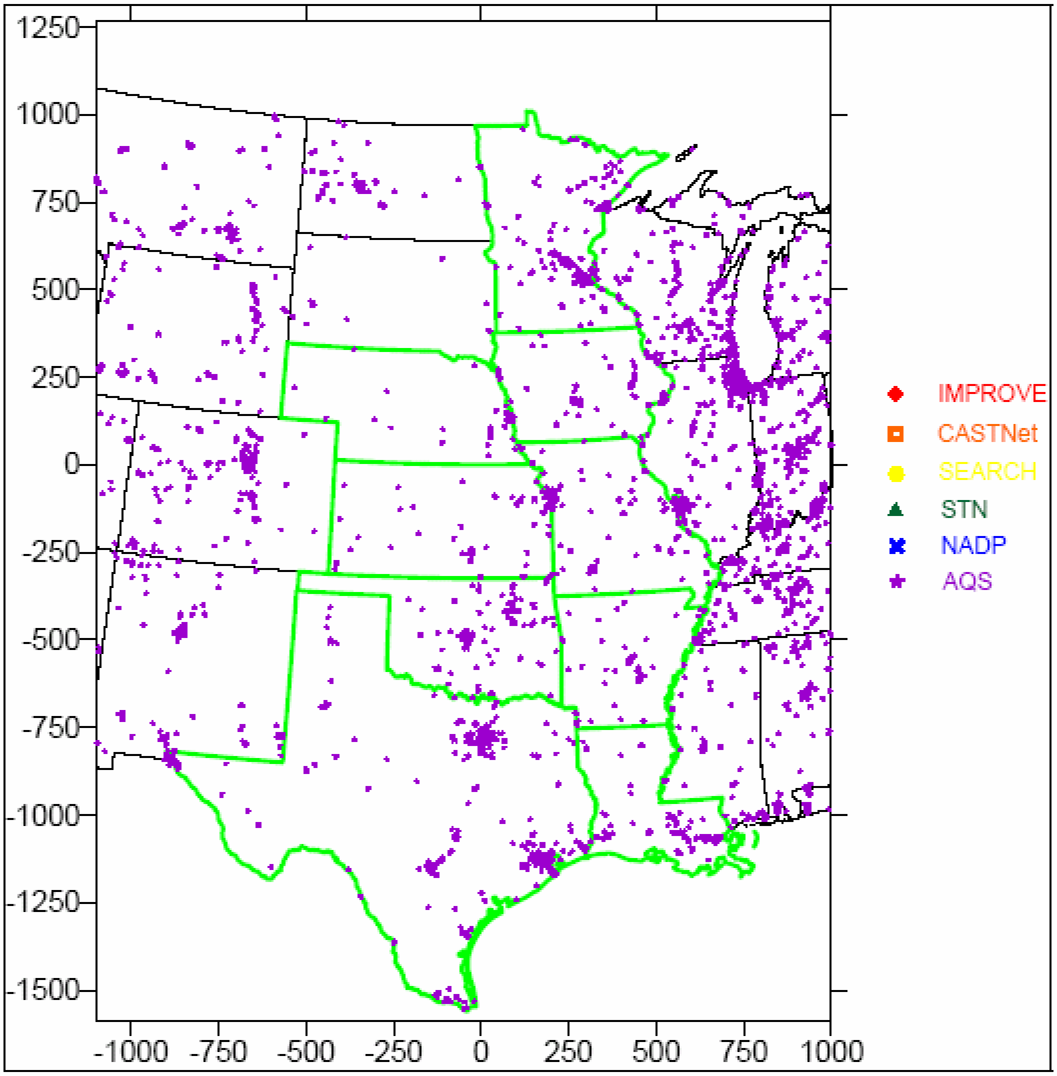


Figure 5-6. Locations of AQS Monitoring Sites in and Near the CENRAP States.

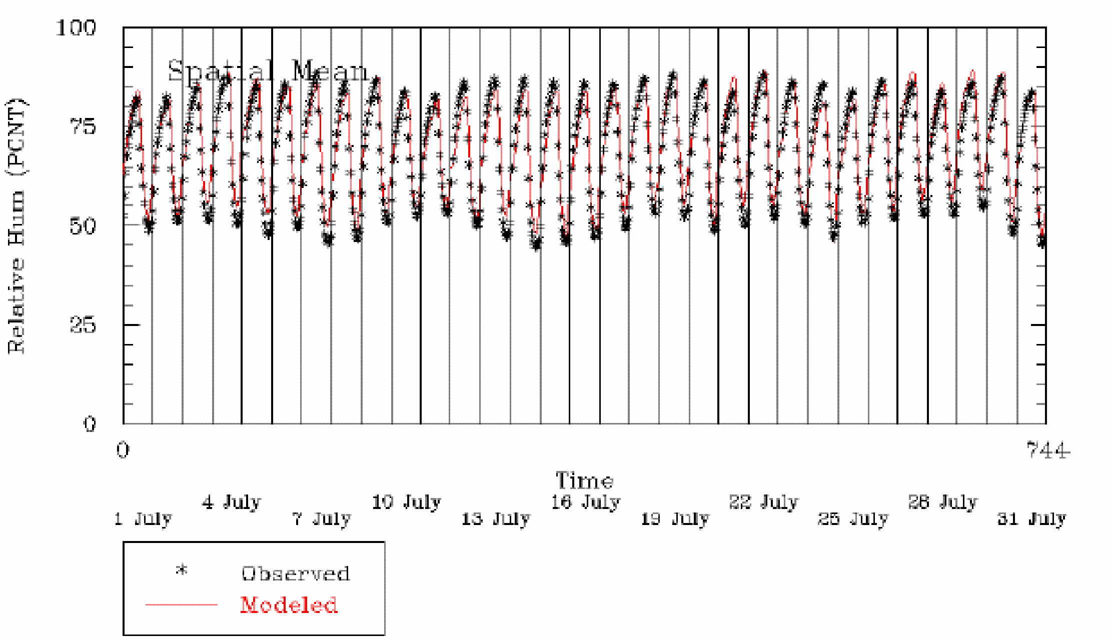


Figure 5-7. Spatial Mean Relative Humidity (%) over the Central Domain: July 2002.

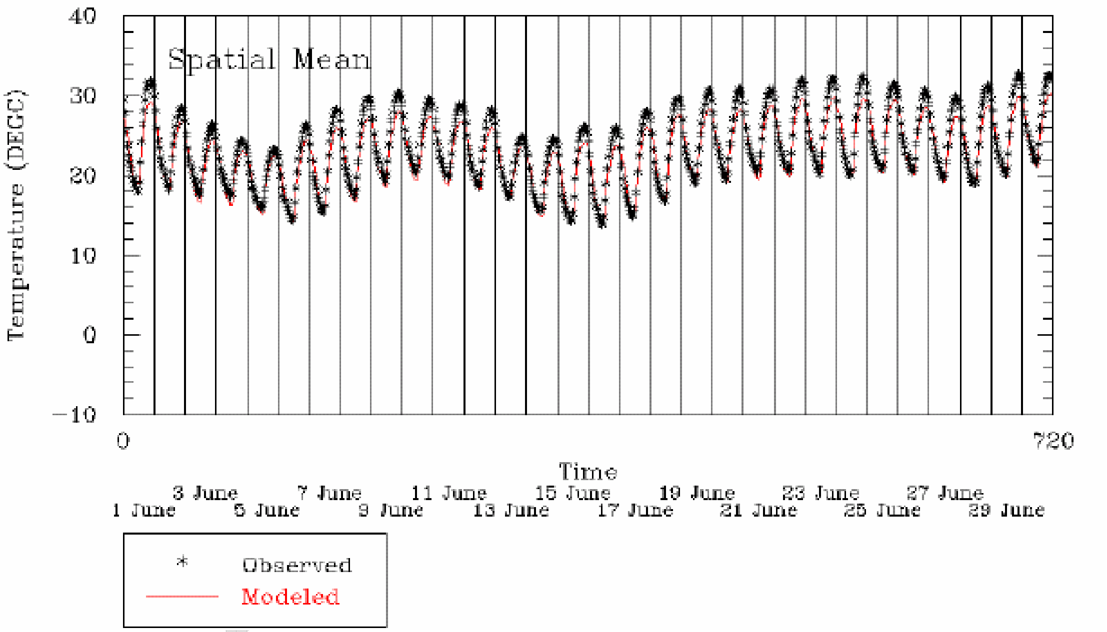


Figure 5-8. Spatial Mean Surface Temperature (deg C) over the Central Domain: July 2002.

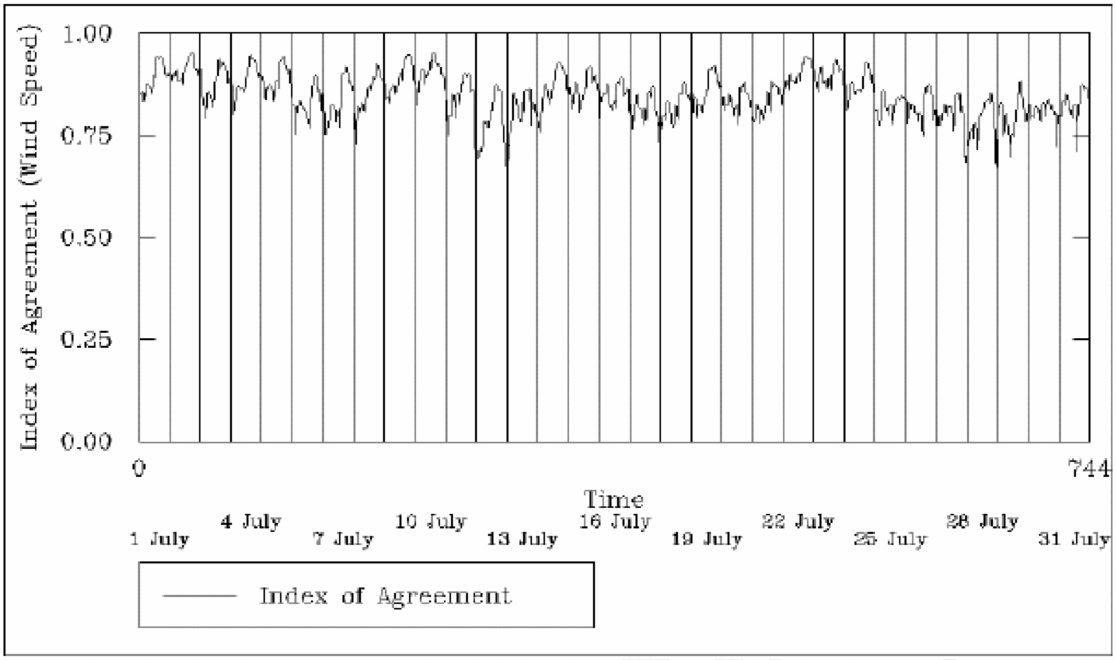


Figure 5-9. Wind Speed Index of Agreement over the Central Domain: July 2002.

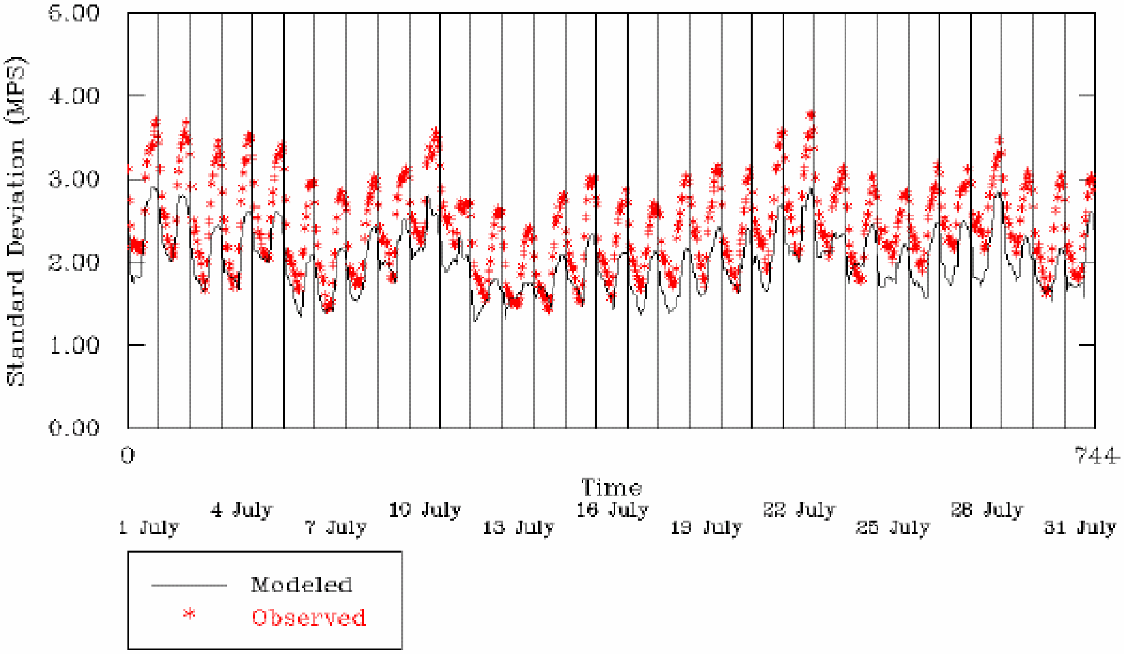


Figure 5-10. Standard Deviation in Wind Speed (m/s) over the Central Domain: July 2002.

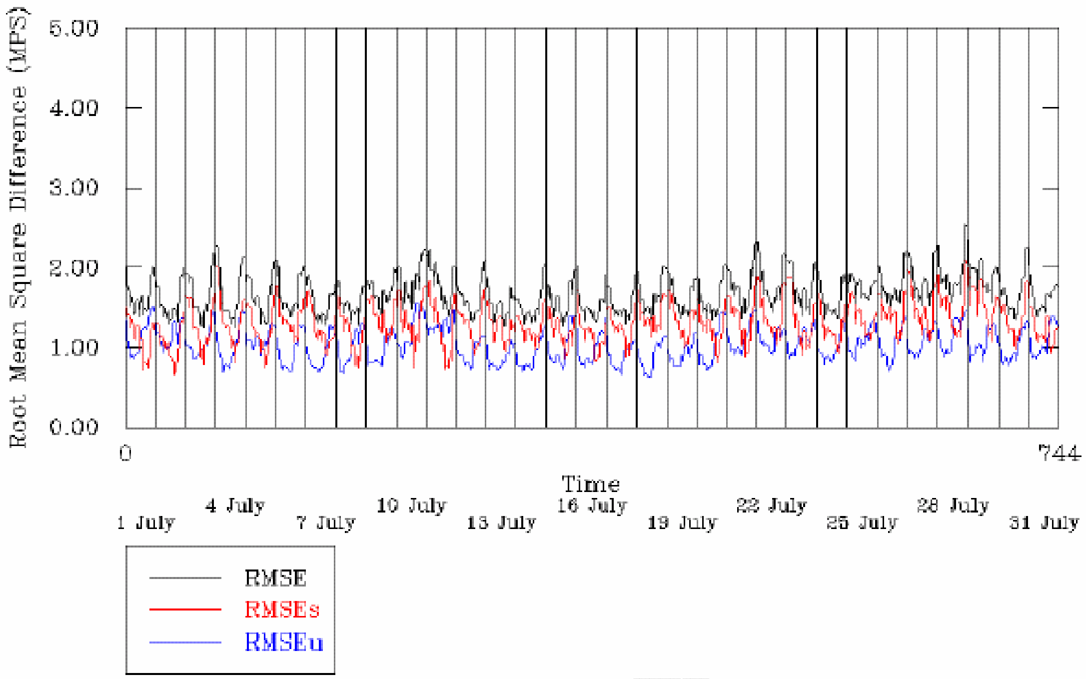


Figure 5-11. Root Mean Square Error in Wind Speed (m/s) over the Central Domain: July 2002**.**

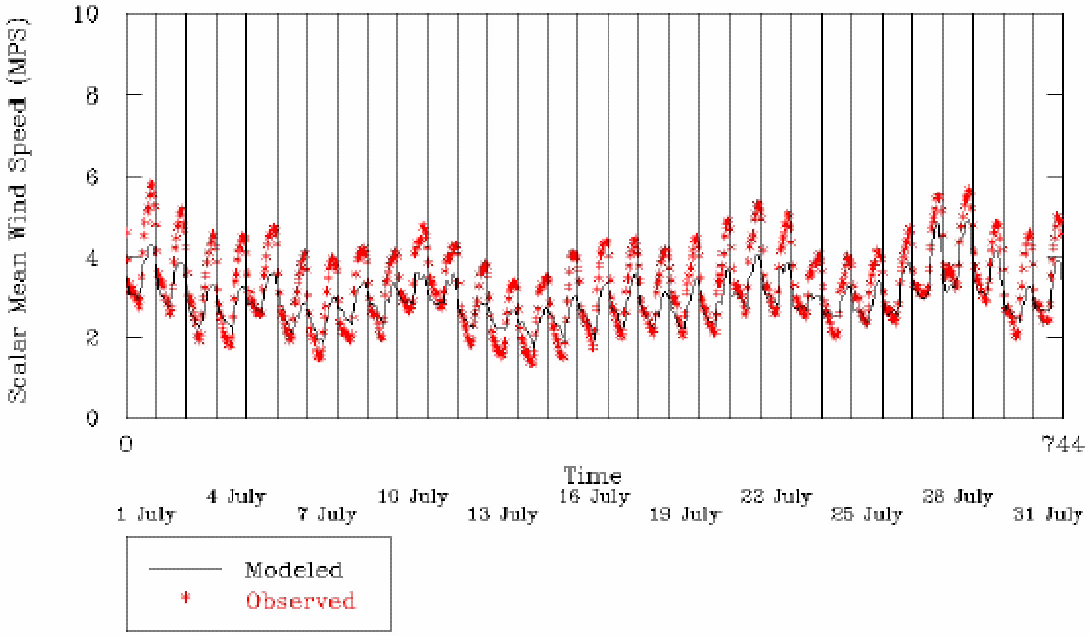


Figure 5-12. Scalar Mean Wind Speed (m/s) over the Central Domain: July 2002.

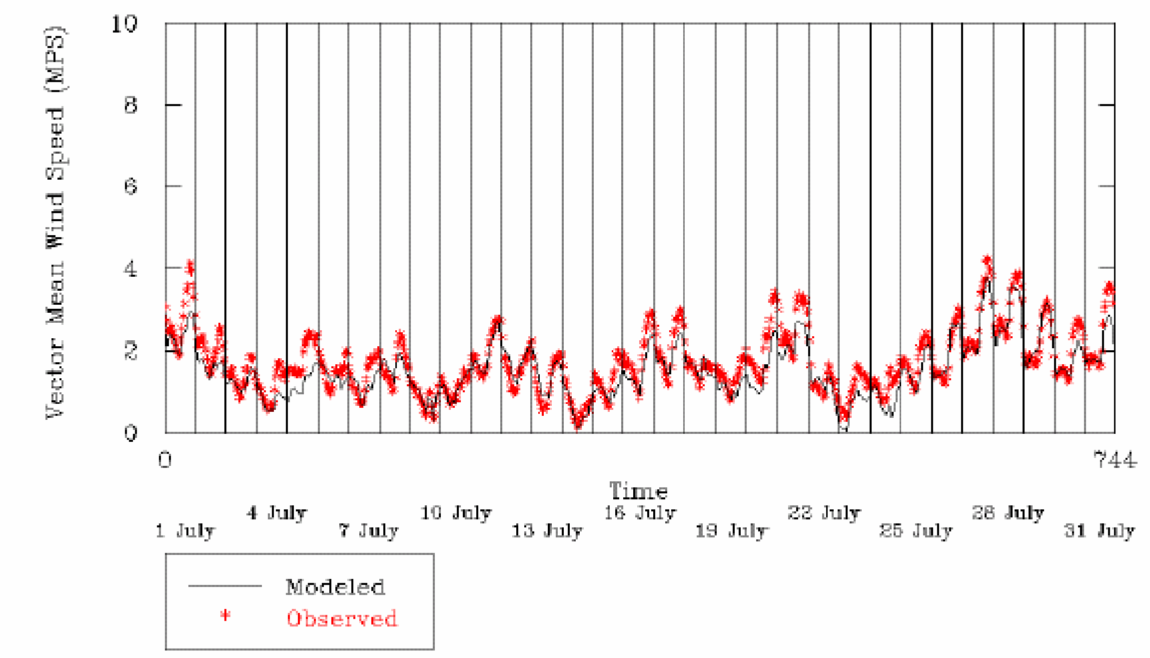


Figure 5-13. Vector Mean Wind Speed (m/s) over the Central Domain: July 2002.

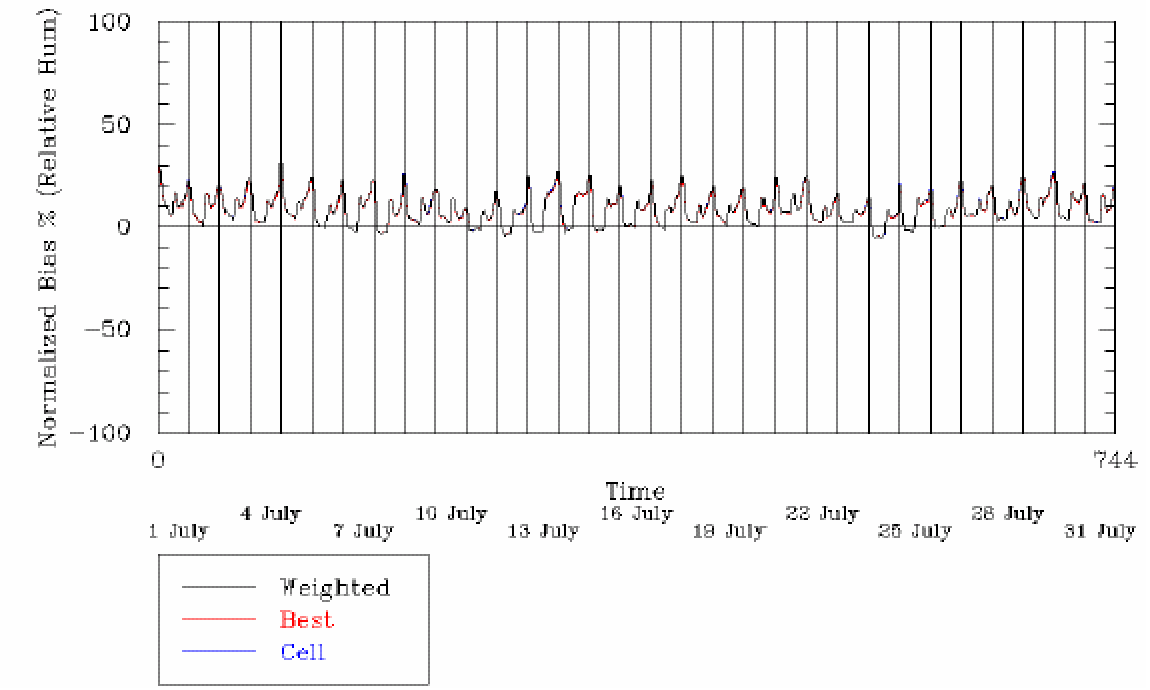


Figure 5-14. Normalized Bias in Relative Humidity (%) over the Central Domain: July 2002.

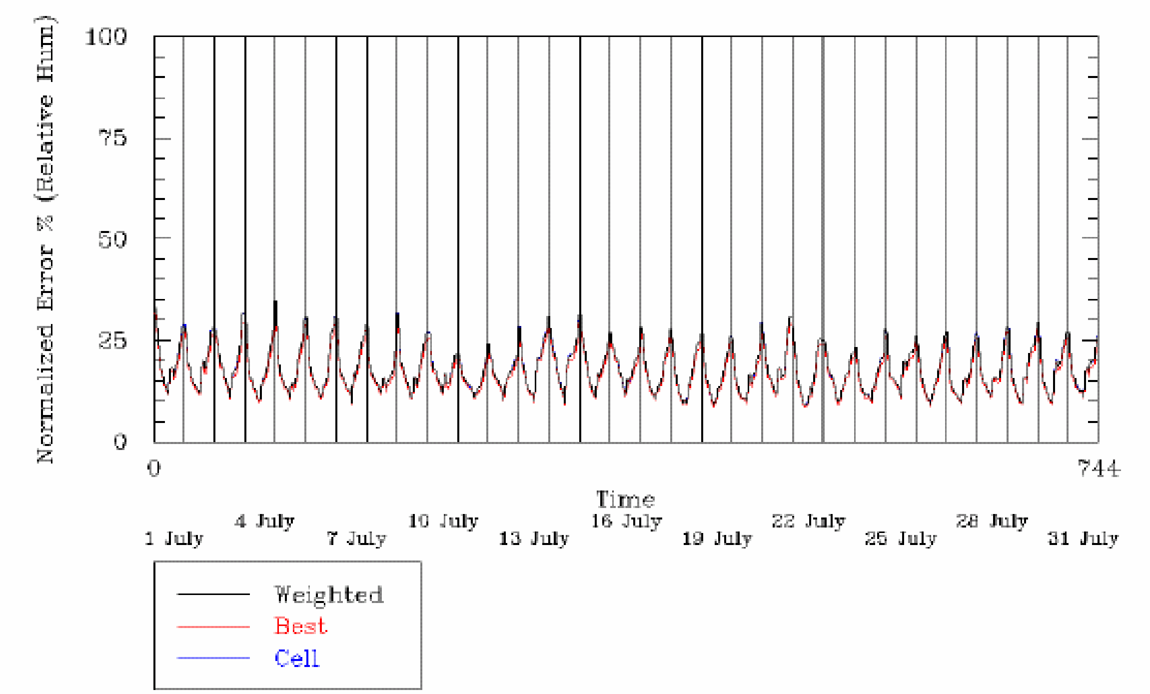


Figure 5-15. Normalized Error in Relative Humidity (%) over the Central Domain: July 2002.

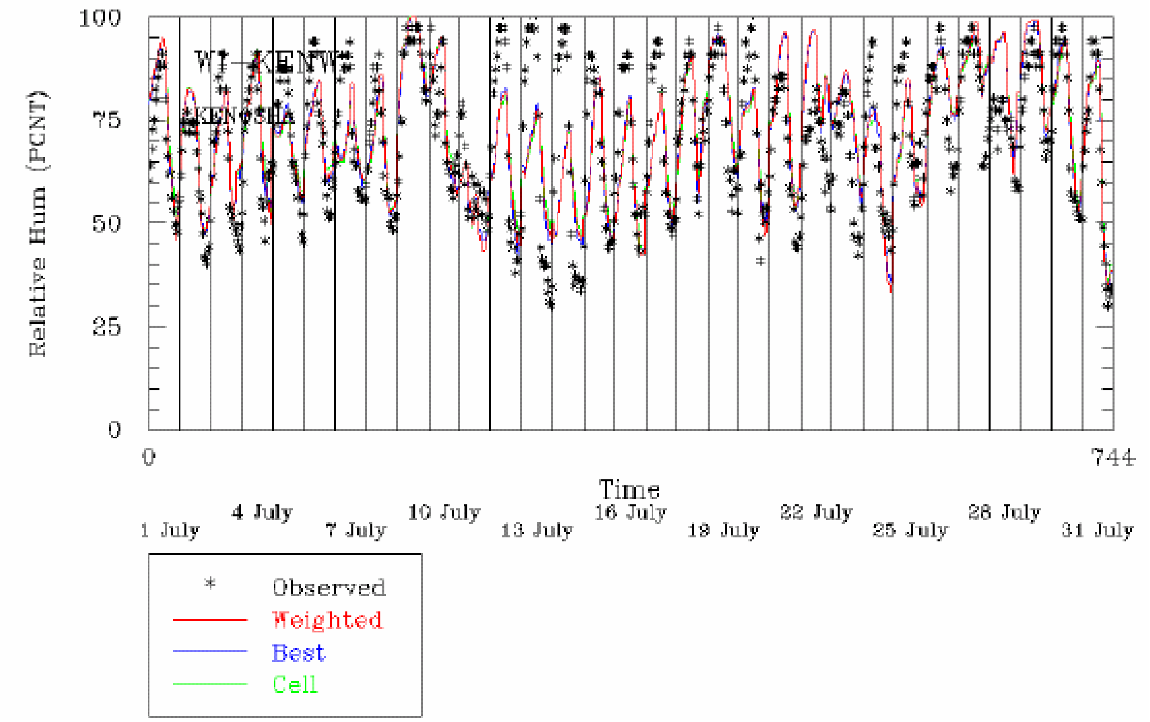


Figure 5-16. Relative Humidity (%) at Kenosha, WI: July 2002.

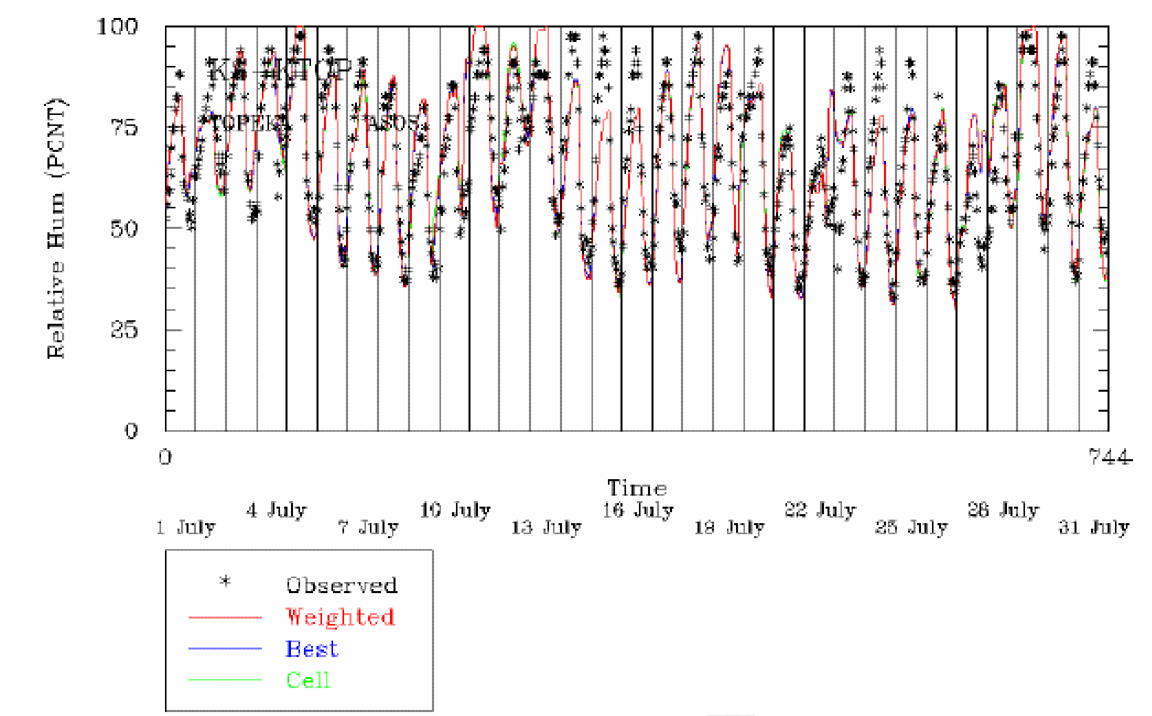


Figure 5-17. Relative Humidity (%) at Topeka, KS: July 2002.

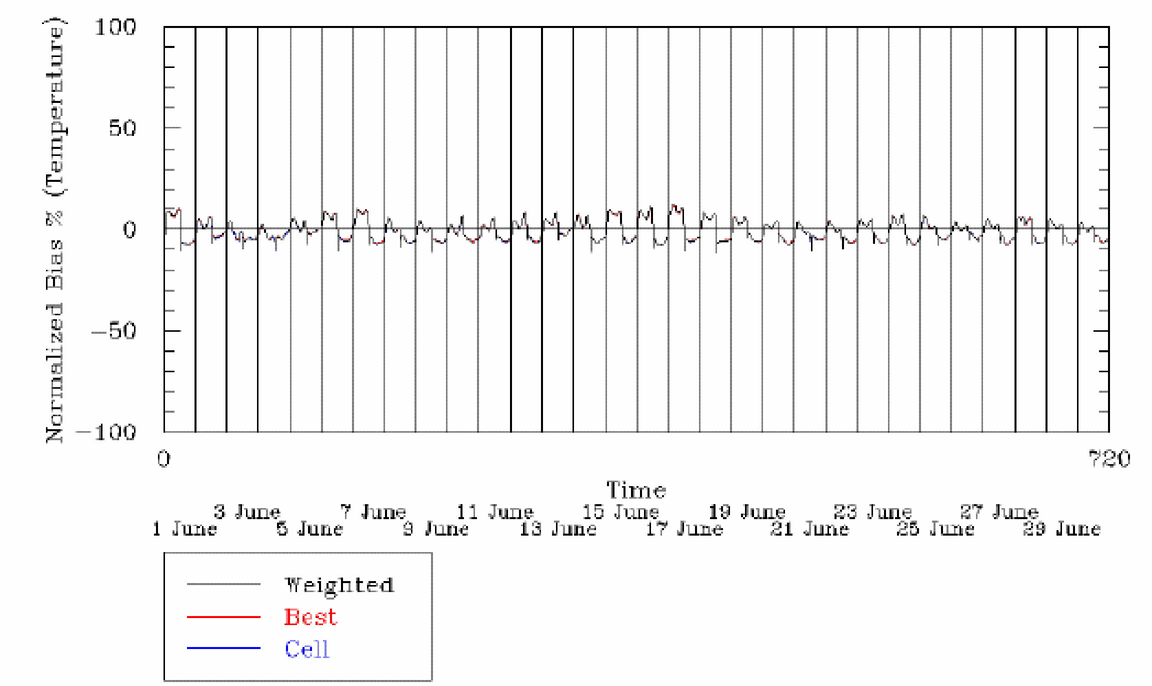


Figure 5-18. Normalized Bias in Surface Temperature (%) over the Central Domain: July 2002.

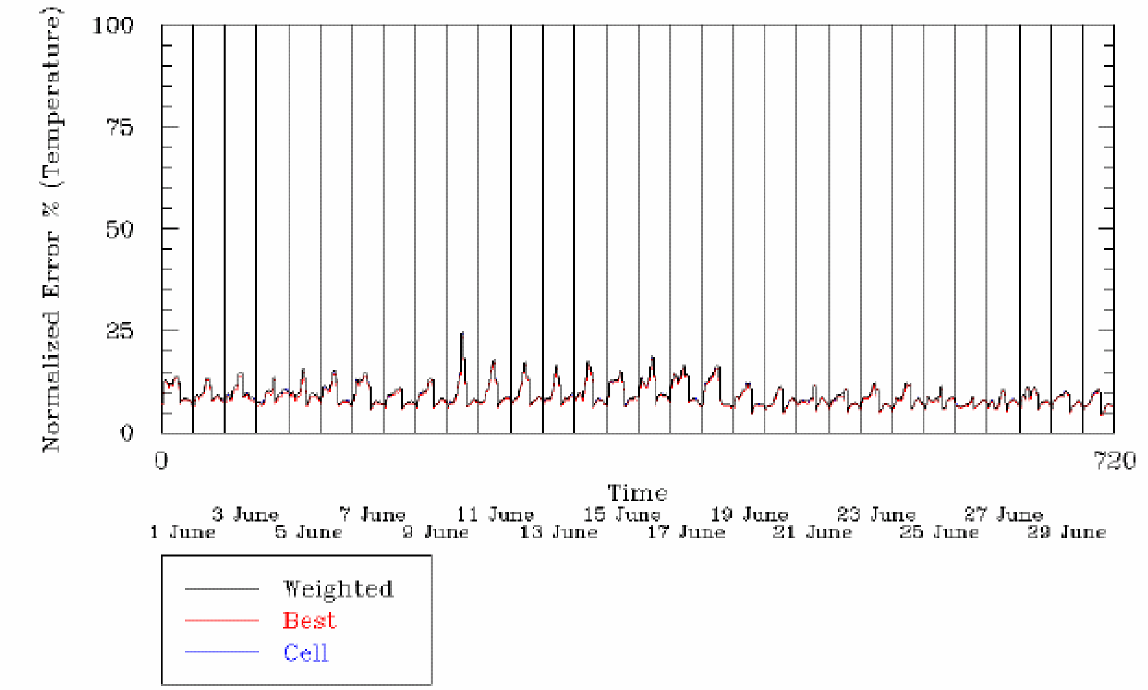


Figure 5-19. Normalized Error in Surface Temperature over the Central Domain: July 2002.

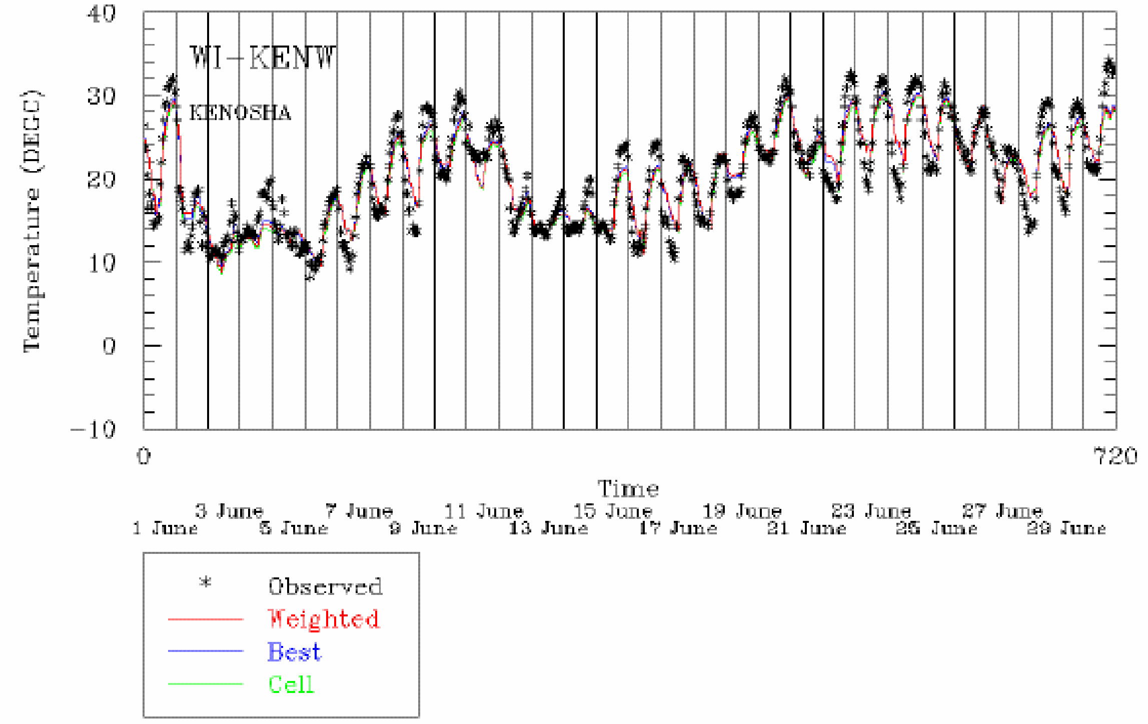


Figure 5-20. Surface Temperature (deg C) at Kenosha, WI: July 2002.

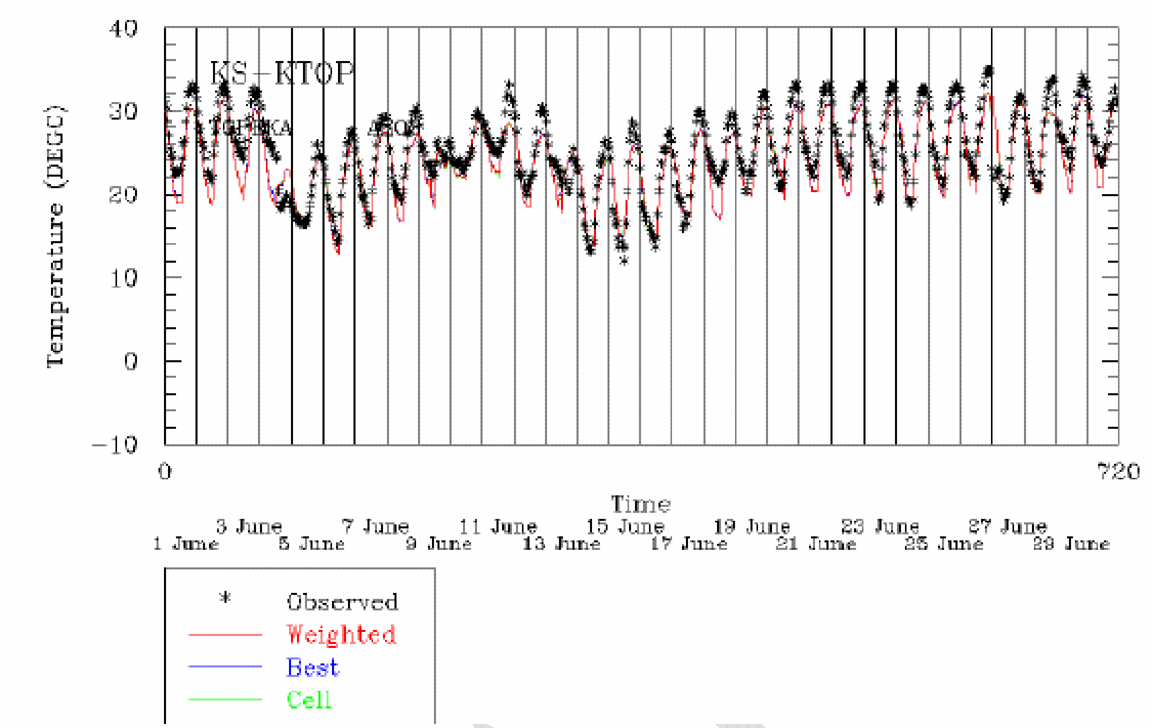
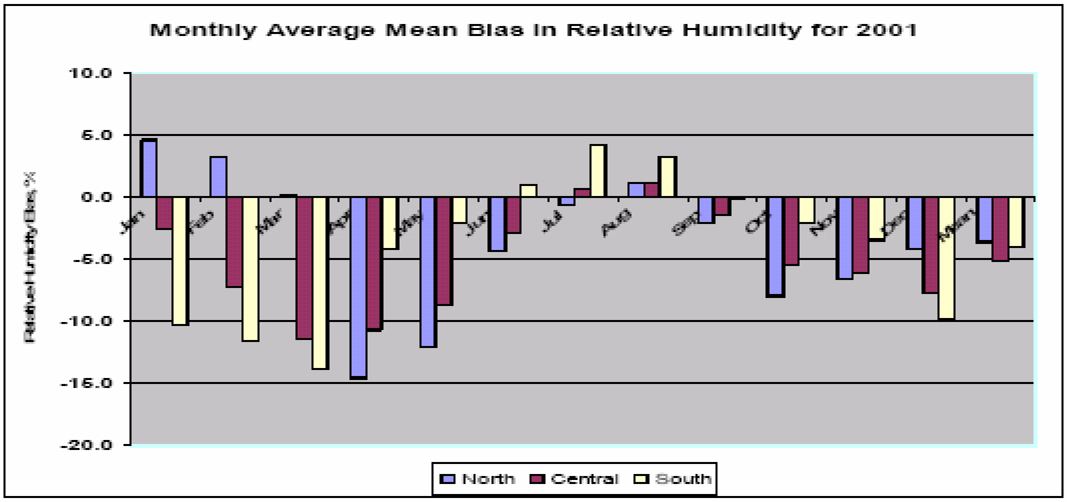
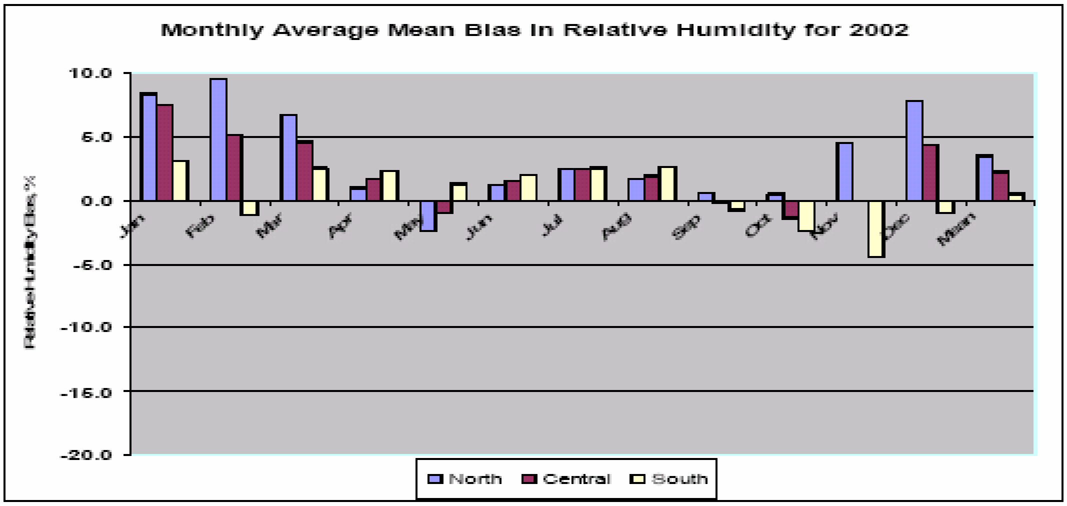


Figure 5-21. Surface Temperature at Topeka, KS: July 2002.





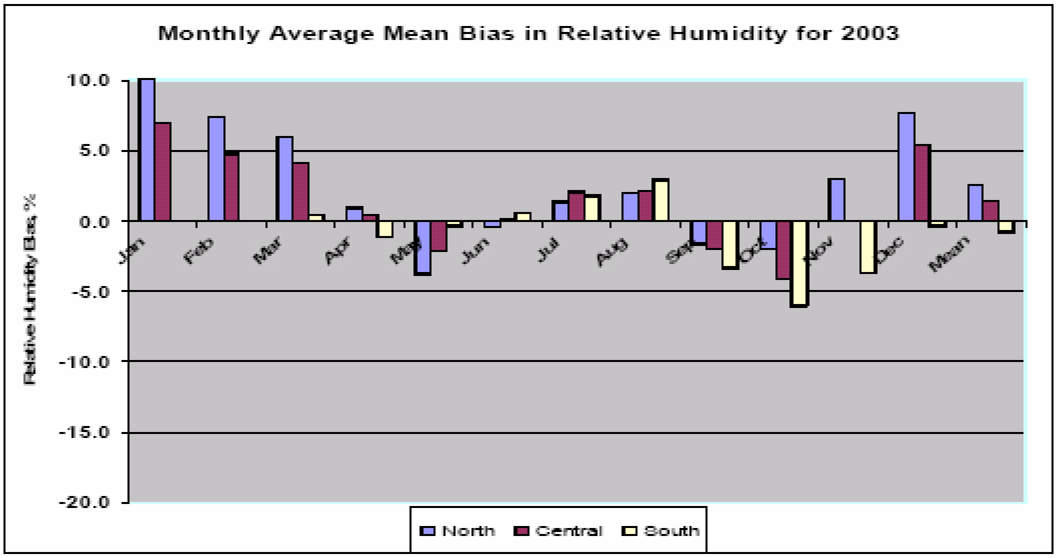


Figure 5-22. MM5/CALMET Relative Humidity Bias (%) by Month for Three BART Modeling Years (2001, 2003, and 2003).

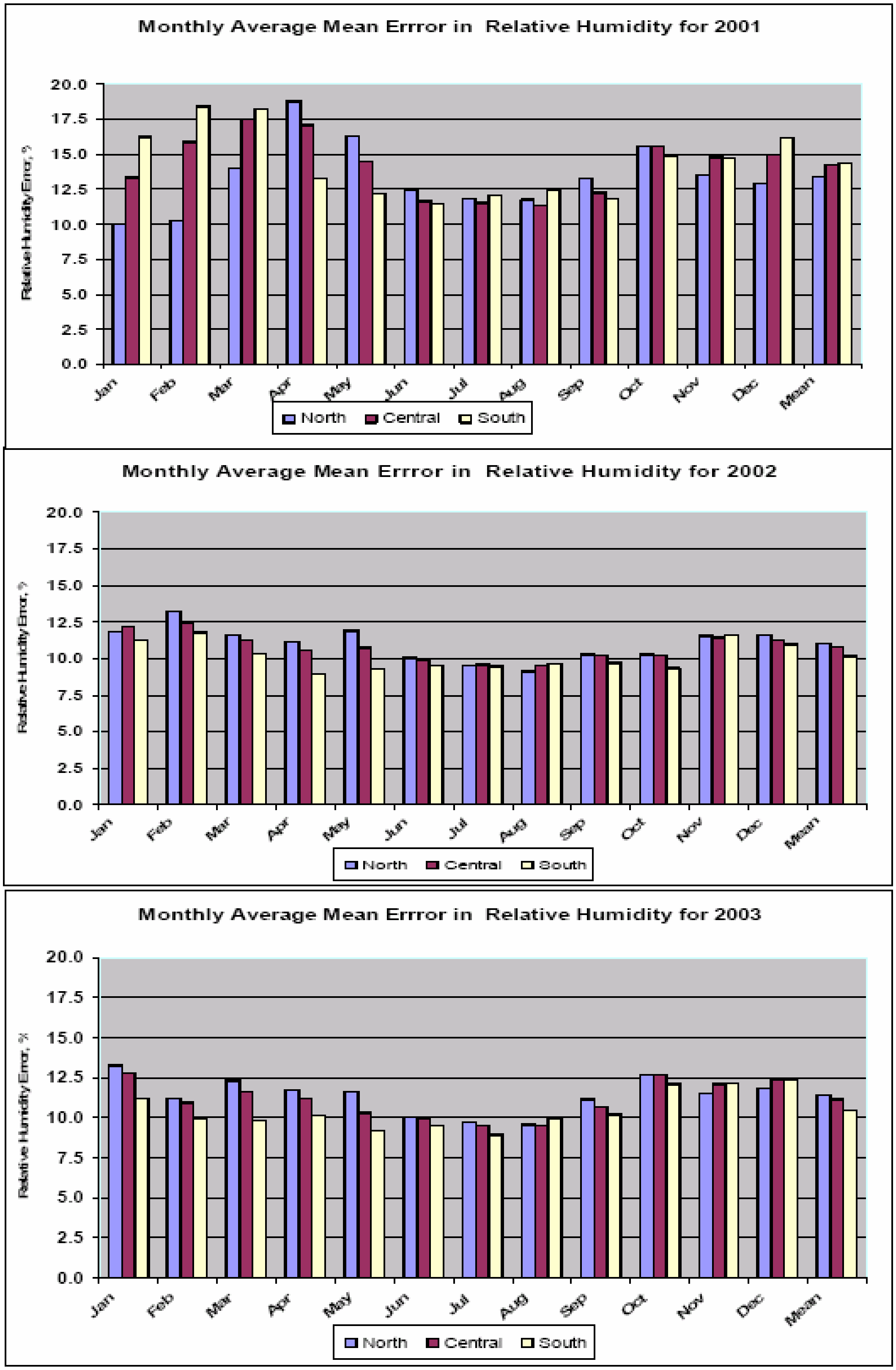


Figure 5-23. MM5/CALMET Relative Humidity Error (%) by Month for Three BART Modeling Years (2001, 2003, and 2003).

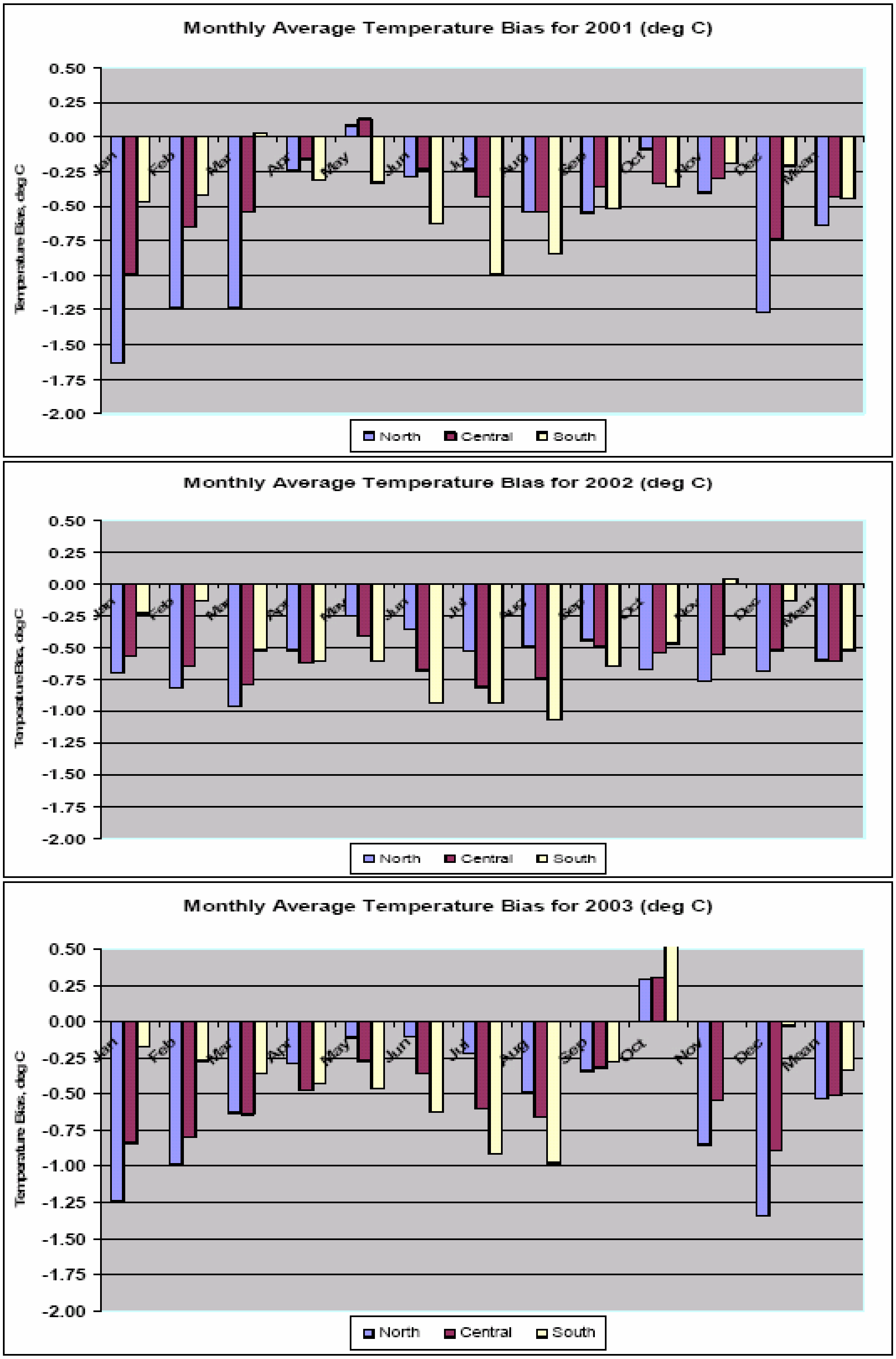
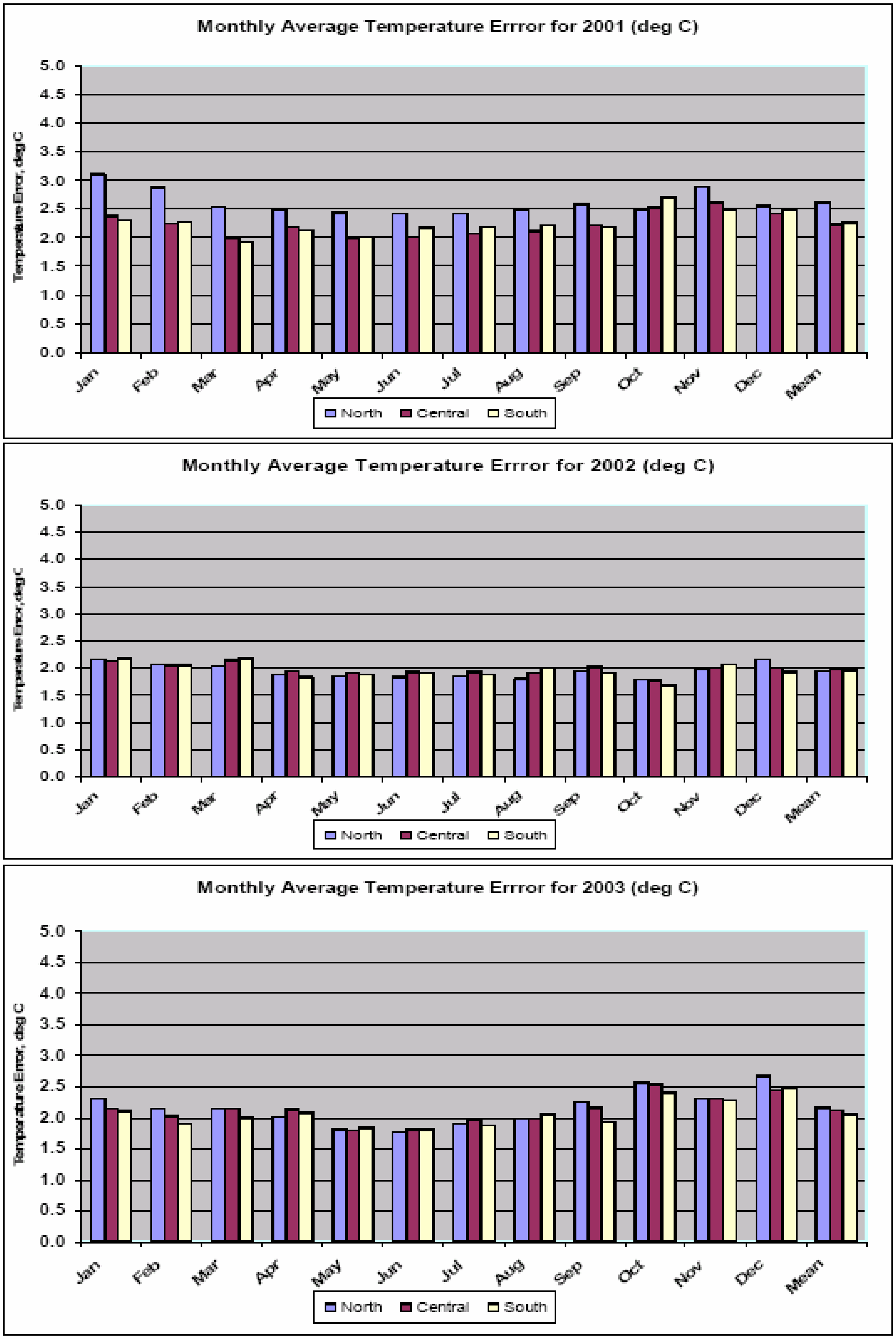


Figure 5-24. MM5/CALMET Temperature Bias (deg C) by Month for Three BART Modeling Years (2001, 2003, and 2003).



Monthly Average Temperature Errror for 2001 (deg C)

Monthly Average Temperature Errror for 2002 (deg C)

Monthly Average Temperature Errror for 2003 (deg C)

Figure 5-25. MM5/CALMET Temperature Error (deg C) by Month for Three BART Modeling Years (2001, 2003, and 2003).

Figure 5-26. MM5/CALMET Wind Speed Index of Agreement by Month for Three BART Modeling Years (2001, 2003, and 2003).

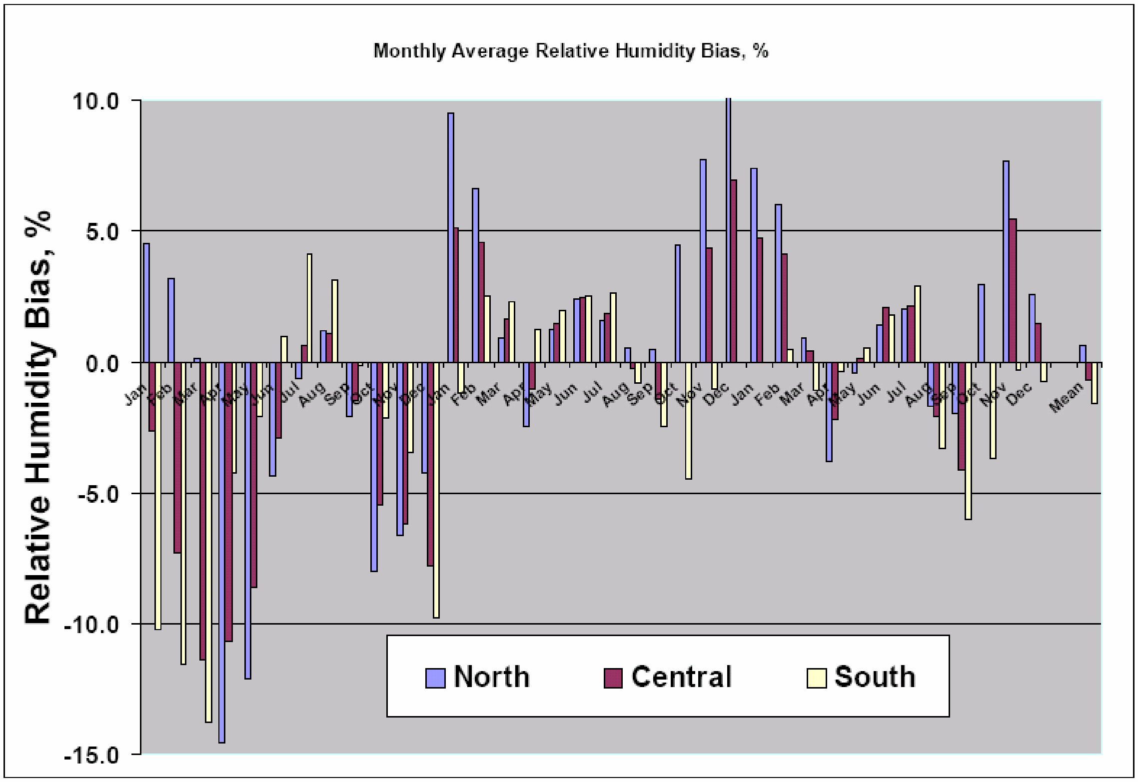


Figure 5-27. MM5/CALMET Relative Humidity Bias (%) over Three Years in All CENRAP Domains.

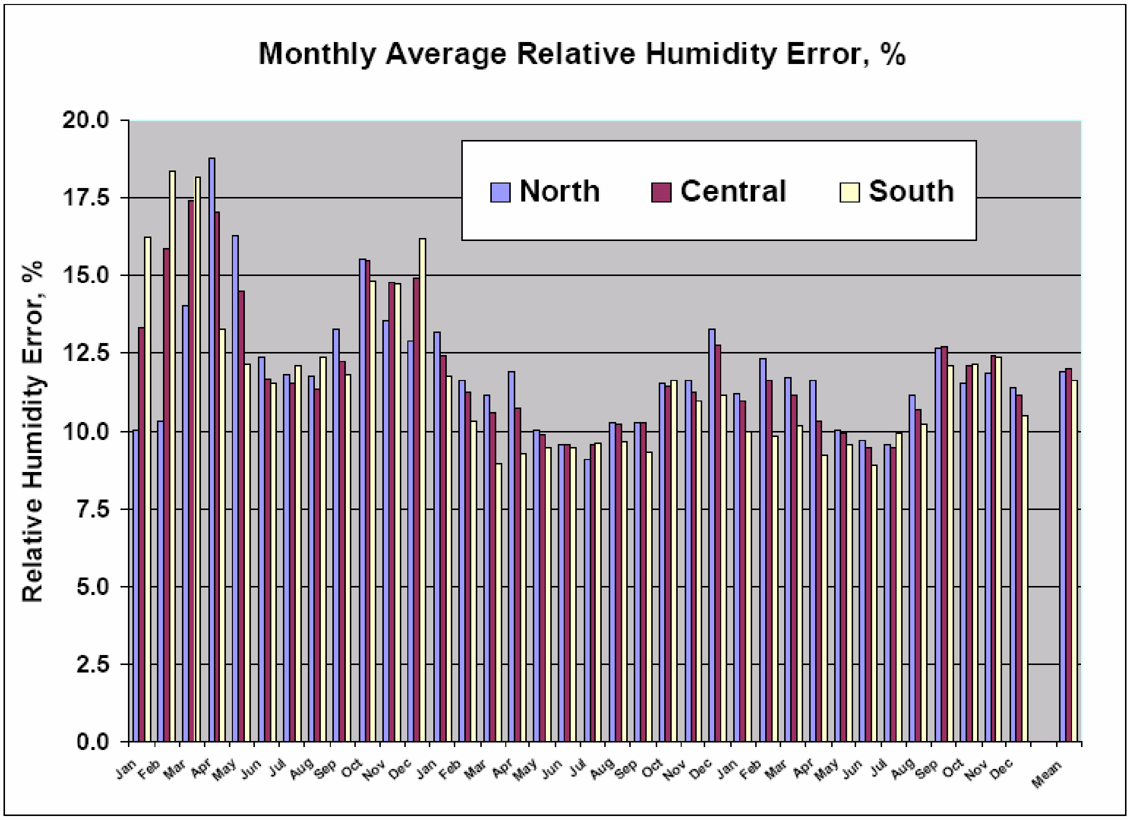


Figure 5-28. MM5/CALMET Relative Humidity Error (%) over Three Years in All CENRAP Domains.

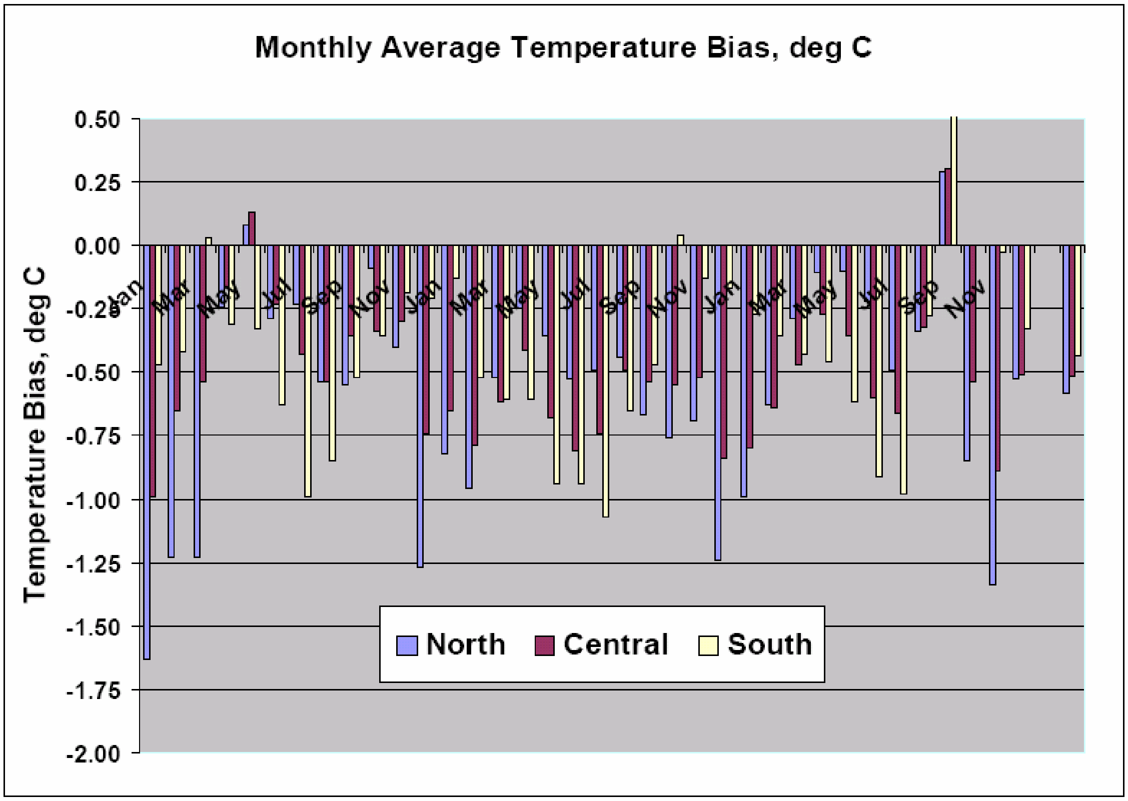


Figure 5-29. MM5/CALMET Surface Temperature Bias (deg C) over Three Years in All CENRAP Domains.

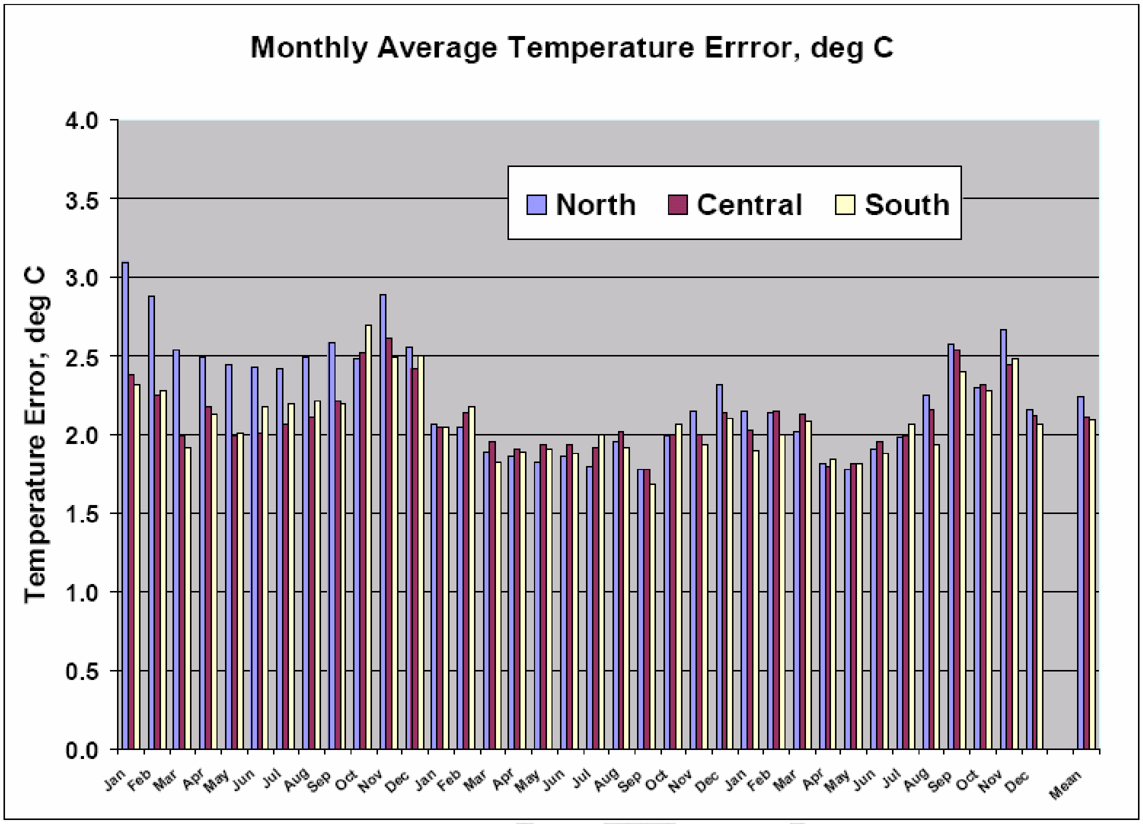


Figure 5-30. MM5/CALMET Surface Temperature Error (deg C) over Three Years in All CENRAP Domains.

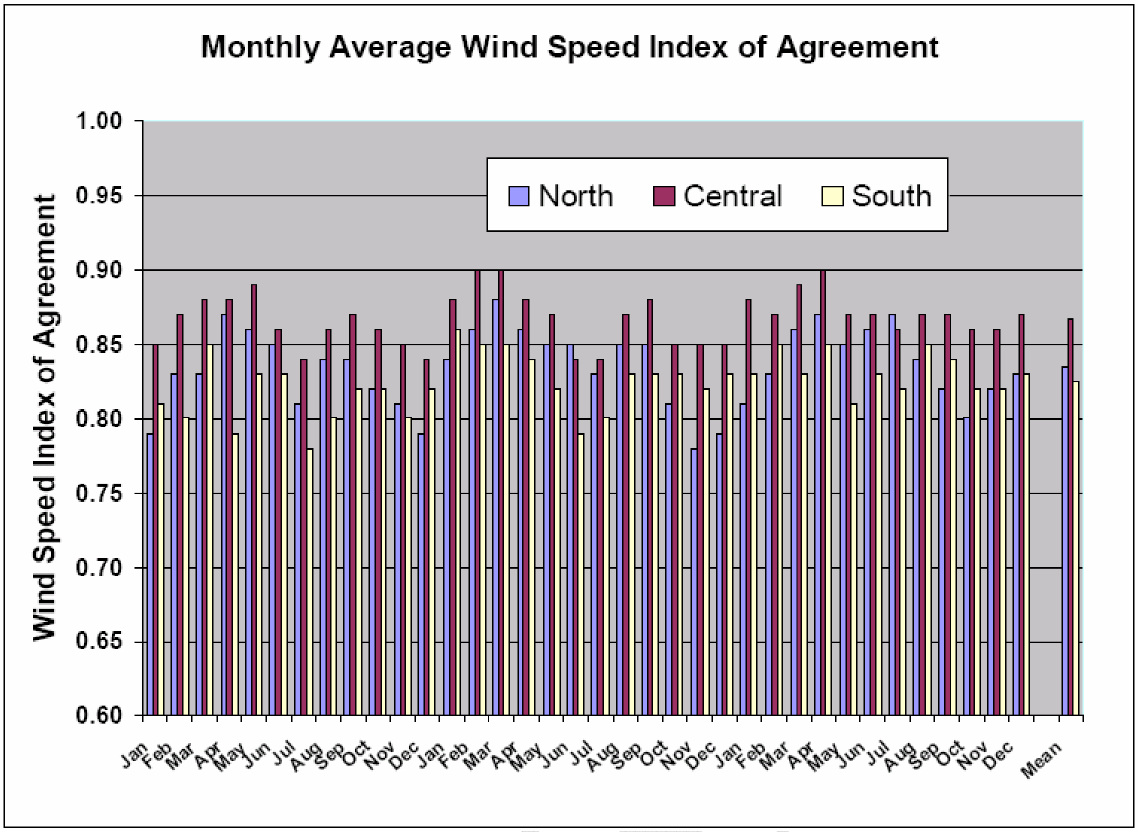


Figure 5-31. MM5/CALMET Wind Speed Index of Agreement over Three Years in All CENRAP Domains.

Appendix F. CALMET Input Control Parameters

Table F-1 Input Groups in the CALMET Control File.

Input Group	Description	Applicable
0	Input and output file names	Yes
1	General run control parameters	Yes
2	Map Projection and Grid Control Parameters	Yes
3	Output Options	Yes
4	Meteorological Data Options	Yes
5	Wind field Options and Parameters	Yes
6	Mixing Height, Temperature and Precipitation Parameters	Yes
7	Surface Meteorological Station Parameters	Yes
8	Upper Air Meteorological Station Parameters	Yes
9	Precipitation Station Parameters	Yes

Table F-2 CALMET Model Input Group 0: Input and Output File Names

Parameter	Default	Value	Comments
Input	GEO.DAT	GEO.DAT	
Input	SURF.DAT	SURF.DAT	
Input	CLOUD.DAT	CLOUD.DAT	
Input	PRECIP.DAT	PRECIP.DAT	
Input	MM4.DAT	MM4.DAT	
Input	WT.DAT	WT.DAT	
Output	CALMET.LST	CALMET.LST	
Output	CALMET.DAT	CALMET.DAT	
Output	PACOUT.DAT	PACOUT.DAT	
NUSTA	--	0	Number of upper air stations
NOWSTA	--	0	Number of over water stations
Input	UP1.DAT	UP1.DAT	
Input	UP2.DAT	UP2.DAT	
Input	UP3.DAT	UP3.DAT	
Input	SEA1.DAT	SEA1.DAT	
Input	DIAG.DAT	DIAG.DAT	
Input	PROG.DAT	PROG.DAT	
Output	TEST.PRT	TEST.PRT	
Output	TEST.OUT	TEST.OUT	
Output	TEST.KIN	TEST.KIN	
Output	TEST.FRD	TEST.FRD	
Output	TEST.SLP	TEST.SLP	

Table F-3 CALMET Model Input Group 1: General Run Control Parameters

Parameter	Default	Value	Comments
IBYR	-	2001	Starting year
IBMO	-	1	Starting month
IBDY	-	1	Starting day
IBHR	-	1	Starting hour
IBTZ	-	6	Base time zone
IRLG	-	8760	Length of run
IRTYPE	1	1	Run type (must = 1 to run CALPUFF)
LCALGRD	T	F	Compute CALGRID data fields
ITEST	2	2	Stop run after SETUP to do input QA

Table F-4 CALMET Model Input Group 2: Map Projection and Grid Control Parameters

Parameter	Default	Value	Comments
PMAP	UTM	LCC	Map Projection
RLATO	--	40N	Latitude (dec. degrees) of projection origin
RLONO	--	97W	Longitude (dec. degrees) of projection origin
XLAT1	--	33N	Matching parallel(s) of latitude for projection
XLAT2	--	45N	Matching parallel(s) of latitude for projection
DATUM	WGS-G	WGS-G	
NX	--	300	Number of X grid cells in meteorological grid
NY	--	192	Number of Y grid cells in meteorological grid
DGRIDKM	--	6.0	Grid spacing, km
XORIGKM	--	-1008.	Ref. Coordinate of SW corner of grid cell (1,1)
YORIGKM	--	0.0	Ref. Coordinate of SW corner of grid cell (1,1)
NZ	--	10	No. of vertical layers
ZFACE	--	0, 20 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000	Cell face heights in arbitrary vertical grid, m

Table F-5 CALMET Model Input Group 3: Output Options

Parameter	Default	Value	Comments
LSAVE	T	T	Disk output option
IFORMO	1	1	Type of unformatted output file
LPRINT	F	F	Print met fields
IPRINF	1	1	Print intervals
IUVOUT(NZ)	NZ*0	NZ*0	Specify layers of u,v wind components to print
IWOUT(NZ)	NZ*0	NZ*0	Specify layers of w wind component to print
ITOUT(NZ)	NZ*0	NZ*0	Specify levels of 3-D temperature field to print
LDB	F	F	Print input met data and variables
NN1	1	1	First time step for debug data to be printed
NN2	1	1	Last time step for debug data to be printed
IOUTD	0	0	Control variable for writing test/debug wind fields
NZPRN2	1	0	Number of levels starting at surface to print
IPR0	0	0	Print interpolated wind components
IPR1	0	0	Print terrain adjusted surface wind components
IPR2	0	0	Print initial divergence fields
IPR3	0	0	Print final wind speed and direction
IPR4	0	0	Print final divergence fields
IPR5	0	0	Print winds after kinematic effects
IPR6	0	0	Print winds after Froude number adjustment
IPR7	0	0	Print winds after slope flows are added
IPR8	0	0	Print final wind field components

Table F-6 CALMET Model Input Group 4: Meteorological Data Options

Parameter	Default	Value	Comments
NOOBS	0	2	2 = No surface, over water, or upper air observations; use MM5 for surface, over water, and upper air data
NSSTA	--	0	Number of meteorological surface stations
NPSTA	--	0	Number of precipitation stations
ICLOUD	--	3	Gridded cloud fields
IFORMS	2	2	Formatted surface meteorological data file
IFORMP	2	2	Formatted surface precipitation data file
IFORMC	2	2	Formatted cloud data file

Table F-7 CALMET Model Input Group 5: Wind field Options and Parameters

Parameter	Default	CENRAP	Comments
IWFCOD	1	1	Model selection variable
IFRADJ	1	1	Compute Froude number adjustment effects?
IKINE	0	0	Compute kinematic effects?
IOBR	0	0	Use O'Brien (1970) vertical velocity adjustment?
ISLSOPE	1	1	Compute slope flow effects?
IEXTRP	-4	-1	Extrapolate surface wind obs to upper levels?
ICALM	0	0	Extrapolate surface winds even if calm?
BIAS	NZ*0	0, 0, 0, 0, 0, 0, 0, 0, 0, 0	Layer-dependent biases weighting aloft measurements
RMIN2	4.	-1.0	Minimum vertical extrapolation distance
IPROG	0	14	14 = Yes, use winds from MM5.DAT file as initial guess field [IWFCOD = 1
ISTEPPG	1	1	MM5 output time step
LVARY	F	T	Use varying radius of influence
RMAX1	--	30.	Maximum radius of influence over land in sfc layer
RMAX2	--	30.	Maximum radius of influence over land aloft
RMAX3	--	50.	Maximum radius of influence over water
RMIN	0.1	0.1	Minimum radius of influence used anywhere
TERRAD	--	12.	Terrain features radius of influence
R1	--	1.	Weighting of first guess surface field
R2	--	1.	Weighting of first guess aloft field
RPROG	--	0.	MM5 windfield weighting parameter
DIVLIM	5.E-6	5.E-6	Minimum divergence criterion
NITER	50	50	Number of divergence minimization iterations
NSMMTH	2, 4, 4, 4, 4, 4, 4	2, 4, 4, 4, 4, 4, 4	Number of passes through smoothing filter in each layer of CALMET
NITR2	99.	5, 5, 5, 5, 5, 5, 5, 5, 5, 5	Maximum number of stations used in each layer for the interpolation of data to a grid point
CRITFN	1.0	1.0	Critical Froude number
ALPHA	0.1	0.1	Kinematic effects parameter
FEXTR2	NZ*0.0	NZ*0.0	Scaling factor for extrapolating sfc winds aloft
NBAR	0	0	Number of terrain barriers
IDIOTP1	0	0	Surface temperature computation switch
ISURFT	--	4	Number of sfc met stations to use for temp calcs
IDIOPT2	0	0	Domain-averaged lapse rate switch
IUPT	0	2	Upper air stations to use for lapse rate calculation
ZUPT	200.	200.	Depth through which lapse rate is calculated
IDIOPT3	0	0	Domain-averaged wind component switch

IUPWND	-1	-1	Number of aloft stations to use for wind calc
ZUPWND	1., 1000.	1., 1000.	Bottom and top of layer through which the domain-scale winds are computed
IDIOPT4	0	0	Observed surface wind component switch
IDIOPT5	0	0	Observed aloft wind component switch
LLBREZE	F	F	Use Lake Breeze Module
NBOX	0	0	Number of lake breeze regions
NLB	--	0	Number of stations in the region
METBXID(NLB)	--	0	Station ID's in the region

Table F-8 CALMET Model Input Group 6: Mixing Height, Temperature and Precipitation

Parameter	Default	Value	Comments
CONSTB	1.41	1.41	Neutral stability mixing height coefficient
CONSTE	0.15	0.15	Convective stability mixing height coefficient
CONSTN	2400.	2400.	Stable stability maxing height coefficient
CONSTW	0.16	0.16	Over water mixing height coefficient
FCORIOL	1.E-4	1.E-4	Absolute value of Coriolis parameter
IAVEZI	1	1	Conduct spatial averaging? Yes = 1
MNMDAV	1	10	Maximum search radius in averaging process
HAFANG	30.	30.	Half-angle of upwind looking cone for averaging
ILEVZI	1	1	Layers of wind use in upwind averaging
DPTMIN	0.001	0.001	Minimum potential temperature lapse rate in the stable layer above the current convective mixing ht
DZZI	200.	200.	Depth of layer above current conv. mixing height through which lapse rate is computed
ZIMIN	50.	50.	Minimum overland mixing height
ZIMAX	3000.	3000.	Maximum overland mixing height
ZIMINW	50.	50.	Minimum over water mixing height
ZIMAXW	3000.	3000.	Maximum over water mixing height
ITPROG	0	2	3D temperature from observations or from MM5?
IRAD	1	1	Type of interpolation; 1 = 1/R
TRADKM	500.	36.	Temperature interpolation radius of influence
NUMTS	5	5	Max number of stations for temp interpolation
IAVET	1	1	Spatially average temperatures? 1 = yes
TGDEFB	-.0098	-.0098	Temp gradient below mixing height over water
TGDEFA	-.0045	-.0045	Temp gradient above mixing height over water
JWAT1	--	55	Beginning land use categories over water
JWAT2	--	55	Ending land use categories for water
NFLAGP	2	2	Precipitation interpolation flag; 2 = 1/R-squared
SIGMAP	100.	50.	Radius of influence for precipitation interpolation
CUTP	0.01	0.01	Minimum precipitation rate cutoff (mm/hr)

Appendix G. CALPUFF Input Control Parameters

Table G-1 Input Groups in the CALPUFF Control File

Input Group	Description	Applicable
0	Input and output file names	Yes
1	General run control parameters	Yes
2	Technical options	Yes
3	Species list	Yes
4	Grid control parameters	Yes
5	Output options	Yes
6	Sub grid scale complex terrain inputs	Yes
7	Dry deposition parameters for gases	Yes
8	Dry deposition parameters for particles	Yes
9	Miscellaneous dry deposition for parameters	Yes
10	Wet deposition parameters	Yes
11	Chemistry parameters	Yes
12	Diffusion and computational parameters	Yes
13	Point source parameters	Yes
14	Area source parameters	No
15	Line source parameters	No
16	Volume source parameters	No
17	Discrete receptor information	Yes

Table G-2 CALPUFF Model Input Group 0: Input and Output File Names

Parameter	Default	Value	Comments
METDAT	CALMET.DAT	Not used	Input file name
PUFLST	CALPUFF.LST	Varies with facility	CALPUFF output file name
CONDAT	CONC.DAT	Varies with facility	Concentration output file name
DFDAT	DFLX.DAT	Varies with facility	Dry flux output file name
WFDAT	WFLX.DAT	Varies with facility	Wet flux output file name
VISDAT	VISB.DAT	Varies with facility	Visibility output file name
OZDAT	OZONE.DAT	Varies with year	Ozone input file name
LCFILES	-	T	File names converted to lower case
NMETDAT	1	12	Number of CALMET.DAT files for run
CALMET.DAT	-	METDAT=/location of CALMET.DAT files	12 entries one for each month

Table G-3 CALPUFF Model Input Group 1: General Run Control Parameters

Parameter	Default	Value	Comments
METRUN	0	0	All model periods in met file(s) will be run
IBYR	-	See note 1 below	Starting year
IBMO	-	1	Starting month
IBDY	-	1	Starting day
IBHR	-	1	Starting hour
XBTZ	-	0	Time zone for met files (0 = GMT)
IRLG	-	See note 2 below	Length of run
NSPEC	5	10	Number of MESOPUFF II chemical species
NSE	3	See note 3 below	Number of chemical species to be emitted
ITEST	2	2	Program is executed after SETUP phase
MRESTART	0	0	Do not read or write a restart file during run
NRESPD	0	0	File written only at last period
METFM	1	1	CALMET binary file (CALMET.MET)
AVET	60	60	Averaging time in minutes
PGTIME	60	60	PG Averaging time in minutes

Note 1: Enter the year being modeled (i.e. 2001, 2002, or 2003)

Note 2: Enter 8760 for the years 2001 and 2002 but enter 8748 for the year 2003

Note 3: Enter 6 for the no-obs run and 7 for the refined run

Table G-4 CALPUFF Model Input Group 2: Technical Options

Parameter	Default	Value	Comments
MGAUSS	1	1	Gaussian distribution used in near field
MCTADJ	3	3	Partial plume path terrain adjustment
MCTSG	0	0	Sub-grid-scale complex terrain not modeled
MSLUG	0	0	Near-field puffs not modeled as elongated
MTRANS	1	1	Transitional plume rise modeled
MTIP	1	1	Stack tip downwash used
MSHEAR	0	0	(0, 1) Vertical wind shear (not modeled, modeled)
MSPLIT	0	0	Puffs are not split
MCHEM	1	1	MESOPUFF II chemical parameterization scheme
MAQCHEM	0	0	Aqueous phase transformation **not modeled**
MWET	1	1	Wet removal modeled
MDRY	1	1	Dry deposition modeled
MDISP	3	2	AERMOD dispersion coefficients
MTURBVW	3	3	Use both σ_v and σ_w from PROFILE.DAT to compute σ_y and σ_z (n/a)
MDISP2	3	2	AERMOD dispersion coefficients
MROUGH	0	0	PG σ_y and σ_z **not adjusted** for roughness
MPARTL	1	1	**No partial plume** penetration of elevated inversion

MTINV	0	0	Strength of temperature inversion computed from default gradients
MPDF	0	0	PDF **not used** for dispersion under convective conditions
MSGTIBL	0	0	Sub-grid TIBL module **not used** for shoreline
MBCON	0	0	Boundary concentration conditions **not modeled**
MFOG	0	0	**Do not** configure for FOG model output
MREG	1	1	Technical options must conform to USEPA Long Range Transport (LRT) guidance

Table G-5 CALPUFF Model Input Group 3: Species List-Chemistry Options

CSPEC	Modeled[1]	Emitted[2]	Dry Deposition[3]	Output Group Number
SO_2	1	1	1	0
SO_4^{-2}	1	0	2	0
NOx	1	1	1	0
HNO_3	1	0	1	0
NO_3^-	1	0	2	0
NH_3	0	0	1	0
PM_{10}[4]	1	1	2	0
PMF[4]	1	1	2	0
EC[5]	1	1	2	0
SOA[5]	1	1	2	0

Note 1: 0 = No, 1 = Yes

Note 2: 0 = No, 1 = Yes (Depends on if species is being modeled or not)

Note 3: 0 = none, 1 = computed gas, 2 = computed particle, 3 = user specified

Note 4: Only PMF will be modeled and emitted in the no-obs run; however, both PM_{10} and PMF will be modeled and emitted in the refined analysis

Note 5: EC and SOA will not be modeled nor will it be emitted during the no-obs and the refined runs

Table G-6 CALPUFF Model Input Group 4: Map Projection and Grid Control Parameters

Parameter	Default	Value	Comments
PMAP	UTM	LCC	Map Projection
FEAST	0.0	0.000	False Easting
FNORTH	0.0	0.000	False Northing
RLATO	None	40N	Latitude and Longitude of projection origin
RLONO	None	97W	Latitude and Longitude of projection origin
XLAT1	None	33N	Matching parallel of latitude for map projection
XLAT2	None	45N	Matching parallel of latitude for map projection
DATUM	WGS-84	WGS-G	Datum region for output coordinates
NX	None	366	Number of X grid cells in meteorological grid
NY	None	234	Number of Y grid cells in meteorological grid
NZ	None	10	Number of vertical layers in meteorological grid
DGRIDKM	None	6	Grid spacing (km)
ZFACE	None	0, 20 40, 80, 160, 320, 640, 1200, 2000, 3000, 4000	Cell face heights in meteorological grid (m)
XORIGKM	None	-1008	Reference X coordinate for SW corner of grid cell (1,1) of meteorological grid (km)
YORIGKM	None	-864	Reference Y coordinate for SW corner of grid cell (1,1) of meteorological grid (km)
IBCOMP	None	1	X index of lower left corner of the computational grid
JBCOMP	None	1	Y index of lower left corner of the computational grids
IECOMP	None	366	X index of the upper right corner of the computational grid
JECOMP	None	234	Y index of the upper right corner of the computational grid
LSAMP	T	F	Sampling grid is not used
IBSAMP	None	1	X index of lower left corner of the sampling grid
JBSAMP	None	1	Y index of lower left corner of the sampling grid
IESAMP	None	366	X index of upper right corner of the sampling grid
JESAMP	None	234	Y index of upper right corner of the sampling grid
MESHDN	1	1	Nesting factor of the sampling grid

Table G-7 CALPUFF Model Input Group 5: Output Options

Parameter	Default	Value	Comments
ICON	1	1	Output file CONC.DAT containing concentrations is created
IDRY	1	1	Output file DFLX.DAT containing dry fluxes is created
IWET	1	1	Output file WFLX.DAT containing wet fluxes is created
IVIS	1	1	Output file containing relative humidity data is created
LCOMPRS	T	T	Perform data compression in output file
IMFLX	0	0	Do not calculate mass fluxes across specific boundaries
IMBAL	0	0	Mass balances for each species not reported hourly
ICPRT	0	1	Print concentration fields to the output list file
IDPRT	0	0	Do not print dry flux fields to the output list file
IWPRT	0	0	Do not print wet flux fields to the output list file
ICFRQ	1	1	Concentration fields are printed to output list file every hour (hr)
IDFRQ	1	1	Dry flux fields are printed to output list file every 1 hour
IWFRQ	1	1	Wet flux fields are printed to output list file every 1 hour
IPRTU	1	3	Units for line printer output are in g/m3 for concentration and g/m^2/s for deposition
IMESG	2	2	Messages tracking the progress of run written to screen
LDEBUG	F	F	Logical value for debug output
IPFDEB	1	1	First puff to track
NPFDEB	1	1	Number of puffs to track
NN1	1	1	Meteorological period to start output
NN2	10	10	Meteorological period to end output

Table G-8 CALPUFF Model Input Group 6: Sub-Grid Scale Complex Terrain Input

Parameter	Default	Value	Comments
NHILL	0	0	Number of terrain features
NCTREC	0	0	Number of special complex terrain receptors
MHILL	-	2	Input terrain and receptor data for CTSG hills input in CTDM format
XHILL2M	1	1	Conversion factor for changing horizontal dimensions to meters
ZHILL2M	1	1	Conversion factor for changing vertical dimensions to meters
XCTDMKM	None	0.0 E+00	X origin of CTDM system relative to CALPUFF coordinate system (km)
YCTDMKM	None	0.0 E+00	Y origin of CTDM system relative to CALPUFF coordinate system (km)

Table G-9 CALPUFF Model Input Group 7: Dry Deposition Parameters for Gases

Species	Default	Value	Comments
SO_2	0.1509	0.1509	Diffusivity
	1000.	1000.	Alpha star
	8.0	8.0	Reactivity
	0.0	0.0	Mesophyll resistance
	0.04	0.04	Henry's Law coefficient
NO_x	0.1656	0.1656	Diffusivity
	1.0	1.0	Alpha star
	8.0	8.0	Reactivity
	5.0	5.0	Mesophyll resistance
	3.5	3.5	Henry's Law coefficient
HNO_3	0.1628	0.1628	Diffusivity
	1.0	1.0	Alpha star
	18.0	18.0	Reactivity
	0.0	0.0	Mesophyll resistance
	8.0E-8	8.0E-8	Henry's Law coefficient
	0.000359	0.000359	Henry's Law coefficient

Table G-10 CALPUFF Model Input Group 8: Dry Deposition Parameters for Particles

Species	Default	Value	Comments
SO_4^{-2}	0.48	0.48	Geometric mass mean diameter of SO_4^{-2} (μm)
NO_3^-	2.0	0.48	Geometric mass mean diameter of NO_3^- (μm)
PM_{10}	2.0	6.0	Geometric mass mean diameter of PMC (μm)
PMF	2.0	0.48	Geometric mass mean diameter of PMF (μm)
EC	2.0	0.48	Geometric mass mean diameter of EC (μm)
SOA	0.48	0.48	Geometric mass mean diameter of SOA (μm)

(Geometric Standard Deviation for all species assumed to be 2.0 μm).

Table G-11 CALPUFF Model Input Group 9: Miscellaneous Dry Deposition Parameters

Parameter	Default	Value	Comments
RCUTR	30	30	Reference cuticle resistance (s/cm)
RGR	10	10	Reference ground resistance (s/cm)
REACTR	8	8	Reference pollutant reactivity
NINT	9	9	Number of particle size intervals for effective particle deposition velocity
IVEG	1	1	Vegetation in non-irrigated areas is active and unstressed

Table G-12 CALPUFF Model Input Group 10: Wet Deposition Parameters

Species	Default	Value	Comments
SO_2	3.21E-05	3.21E-05	Scavenging coefficient for liquid precipitation (s^{-1})
	0.0	0.0	Scavenging coefficient for frozen precipitation (s^{-1})
SO_4^{-2}	1.0E-04	1.0E-04	Scavenging coefficient for liquid precipitation (s^{-1})
	3.0E-05	3.0E-05	Scavenging coefficient for frozen precipitation (s^{-1})
HNO_3	6.0E-05	6.0E-05	Scavenging coefficient for liquid precipitation (s^{-1})
	0.0	0.0	Scavenging coefficient for frozen precipitation (s^{-1})
NO_3^-	1.0E-04	1.0E-04	Scavenging coefficient for liquid precipitation (s^{-1})
	3.0E-05	3.0E-05	Scavenging coefficient for frozen precipitation (s^{-1})
NH_3	8.0E-05	8.0E-05	Scavenging coefficient for liquid precipitation (s^{-1})
	0.0	0.0	Scavenging coefficient for frozen precipitation (s^{-1})
PM_{10}	1.0E-04	1.0E-04	Scavenging coefficient for liquid precipitation (s^{-1})
	3.0E-05	3.0E-05	Scavenging coefficient for frozen precipitation (s^{-1})
PMF	1.0E-04	1.0E-04	Scavenging coefficient for liquid precipitation (s^{-1})
	3.0E-05	3.0E-05	Scavenging coefficient for frozen precipitation (s^{-1})
EC	1.0E-04	1.0E-04	Scavenging coefficient for liquid precipitation (s^{-1})
	3.0E-05	3.0E-05	Scavenging coefficient for frozen precipitation (s^{-1})
OC	1.0E-04	1.0E-04	Scavenging coefficient for liquid precipitation (s^{-1})
	3.0E-05	3.0E-05	Scavenging coefficient for frozen precipitation (s^{-1})

Table G-13 CALPUFF Model Input Group 11: Chemistry Parameters

Parameter	Default	Value	Comments
MOZ	1	1	Read ozone background concentrations from ozone.dat file (measured values).
$BCKO_3$	12*80	12*40	Background ozone concentration (ppb)
$BCKNH_3$	12*10	12*3	Background ammonia concentration (ppb)
RNITE1	0.2	0.2	Nighttime NO_2 loss rate in percent/hour
RNITE2	2	2	Nighttime NO_X loss rate in percent/hour
RNITE3	2	2	Nighttime HNO_3 loss rate in percent/hour
MH_20_2	1	1	Background H_2O_2 concentrations (Aqueous phase transformations **not modeled**)
$BCKH_20_2$	1	1	Background monthly H_2O_2 concentrations (Aqueous phase transformations **not modeled**)

Table G-14 CALPUFF Model Input Group 12: Dispersion/Computational Parameters

Parameter	Default	Value	Comments
SYDEP	550	550	Horizontal size of a puff in meters beyond which the time dependant dispersion equation of Heffter (1965) is used
MHFTSZ	0	0	Do **not use** Heffter formulas for sigma z
JSUP	5	5	Stability class used to determine dispersion rates for puffs above boundary layer
CONK1	0.01	0.01	Vertical dispersion constant for stable conditions
CONK2	0.1	0.1	Vertical dispersion constant for neutral/stable conditions
TBD	0.5	0.5	Use ISC transition point for determining the transition point between the Schulman-Scire to Huber-Snyder Building Downwash scheme
IURB1	10	10	Lower range of land use categories for which urban dispersion is assumed
IURB2	19	19	Upper range of land use categories for which urban dispersion is assumed
ILANDUIN	20	*	Land use category for modeling domain
XLAIIN	3.0	*	Leaf area index for modeling domain
ZOIN	-0.25	*	Roughness length in meters for modeling domain
ELEVIN	0.0	*	Elevation above sea level
XLATIN	-999	-	North latitude of station in degrees
XLONIN	-999	-	South latitude of station in degrees
ANEMHT	10	10	Anemometer height in meters
ISIGMAV	1	1	Sigma-v is read for lateral turbulence data
IMIXCTDM	0	0	Predicted mixing heights are used
XMXLEN	1	1	Maximum length of emitted slug in meteorological grid units
XSAMLEN	1	10	Maximum travel distance of slug or puff in meteorological grid units during one sampling unit
MXNEW	99	60	Maximum number of puffs or slugs released from one source during one time step
MXSAM	99	60	Maximum number of sampling steps during one time step for a puff or slug
NCOUNT	2	2	Number of iterations used when computing the transport wind for a sampling step that includes transitional plume rise
SYMIN	1	1	Minimum sigma y in meters for a new puff or slug
SZMIN	1	1	Minimum sigma z in meters for a new puff or slug
SVMIN	.50	.50	Minimum lateral turbulence velocities (m/s)
SWMIN	0.20, 0.12, 0.08, 0.06,	0.20, 0.12, 0.08, 0.06,	Minimum vertical turbulence velocities (m/s)

	0.03, 0.016	0.03, 0.016	
WSCALM	0.5	0.5	Minimum non-calm wind speeds (m/s)
XMAXZI	3000.	3000.	Maximum mixing height (m)
XMINZI	50.	20.	Minimum mixing height (m)
SL2PF	10.	10.	Maximum Sy/puff length
PLXO	0.07, 0.07, 0.10, 0.15, 0.35, 0.55	0.07, 0.07, 0.10, 0.15, 0.35, 0.55	Wind speed power-law exponents
WSCAT	1.54, 3.09, 5.14, 8.23, 10.80	1.54, 3.09, 5.14, 8.23, 10.80	Upper bounds of 1st 5 wind speed classes
PGGO	0.020, 0.035	0.020, 0.035	Potential temp gradients PG E & F (deg/km)
CDIV	0.01	0.01	Divergence criterion for dw/dz (1/s)
PPC	0.5, 0.5, 0.5, 0.5, 0.35, 0.35	0.5, 0.5, 0.5, 0.5, 0.35, 0.35	Plume path coefficients (only if MCTADJ=3)
NSPLIT	3	3	Number of puffs when puffs split
IRESPLIT	-	1900	Hour(s) when puff is eligible to split
ZISPLIT	100	100	Previous hour's minimum mixing height, m
ROLDMAX	0.25	0.25	Previous Max mixing height/current mixing height ratio, must be less than this value to allow puff to split
NSPLITH	5	5	Number of puffs resulting from a split
SYSPLITH	1.0	1.0	Minimum sigma-y of puff before it may split
SHSPLITH	2.0	2.0	Minimum puff elongation rate from wind shear before puff may split
CNSPLITH	1.0E-07	1.0E-07	Minimum species concentration before a puff may split
EPSSLUG	1.0E-04	1.0E-04	Criterion for SLUG sampling
EPSAREA	1.0E-06	1.0E-06	Criterion for area source integration
DSRISE	1.0	1.0	Trajectory step length for numerical rise algorithm
Note: Values indicated by an asterisk (*) were allowed to vary spatially across the domain and were obtained from CALMET			

Table G-15 CALPUFF Model Input Group 13: Point Source Parameters

Parameter	Default	Value	Comments
NPT1	None	Varies by scenario	Number of point sources with stack parameters
IPTU	1	1	Units for point source emission rates are g/s
NSPT1	0	0	Number of source-species combinations with variable emissions scaling factors
NPT2	None	0	Number of point sources with variable emission parameters provided in external file
MISC	None	Point source parameters and emission data	Point source inputs include stack height (H), stack diameter (d), exit temperature (T), exit velocity (v) emissions by species, and coordinate of stack (LCC)

Table G-16 CALPUFF Model Input Group 17: Discrete Receptor Information

Parameter	Default	Value	Comments
NREC	None	427	Number of discrete receptors

Please note that ADEQ will not be modeling area, line and volume sources which are input groups 14, 15, and 16 respectively.

Appendix H. POSTUTIL Input Control Parameters

Table H-1 Input Groups in the POSTUTIL Processor Control File

Sub Group	Description	Applicable
0a	Input and output file names	Yes
1	NMET – Number of CALMET data files (365)	Yes
2	NFILES – Number of CALPUFF data files	Yes

Table H-2 POSTUTIL Processor Input Group 1: General Run Control Parameters

Parameter	Default	Value	Comments
ISYR	None	See note 1 below	Starting year
ISMO	None	1	Starting month
ISDY	None	1	Starting day
ISHR	None	0	Starting hour
NPER	None	See note 2 below	Number of periods to process
NSPECINP	None	See note 3 below	Number of CALPUFF species to process
NSPECOUT	None	See note 3 below	Number of species to output
NSPECCMP	None	0	Number of species to derive
MDUPLCT	None	1	Stop run if duplicate name
NSCALED	None	0	Number of CALPUFF files to 'scale'
MNITRATE	None	1	Re-compute the HNO_3/NO_3 partition for CALPUFF modeled concentrations? 1 = yes for all sources combined
BCKNH3	10.	3.	Default NH_3 concentration (ppb) for HNO_3/NO_3 partitioning

Note 1: Enter the modeled year for the CALPUFF run
Note 2: Enter 8760 for years 2001 and 2002, but enter 8748 for the year 2003
Note 3: Enter 6 for the no-obs run and 7 for the refined run

Table H-3 POSTUTIL Processor Input Group 2: Species Processing Information

Parameter	Default	Value	Comments
ASPECI	None	SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}, PMF See Note 1 Below	Species to post-process
ASPECO	None	SO_2, SO_4, NO_x, HNO_3, NO_3, PM_{10}, PMF See Note 4 Below	Species to output
CSPECCMP	None	CSPECCMP = N SO_2 = 0.0 SO_4 = 0.291667 NO = 0.466667 NO_2 = 0.304348 HNO_3 = 0.222222 NO_3 = 0.451613 PM_{10} = 0.0	Nitrogen species to be computed by scaling and summing one or more of the processed input species using the scaling factors for each of the NSPECINP input species
CSPECCMP	None	CSPECCMP = S SO_2 = 0.50 SO_4 = 0.333333 NO = 0.0 NO_2 = 0.0 HNO_3 = 0.0 NO_3 = 0.0 PM_{10} = 0.0	Sulfur species to be computed by scaling and summing one or more of the processed input species using the scaling factors for each of the NSPECINP input species
MODDAT	None	A (Default=1.0) SO_2 = 1.1 SO_4 = 1.5 HNO3 = 0.8 NO_3 = 0.1 B (Default=0.0) SO_2 = 0.0 SO_4 = 0.0 HNO_3 = 0.0 NO_3 = 0.0	Each species in NSCALED CALPUFF data files may be scaled before processing (e.g., to change the emission rate for all sources modeled in the run that produced a data file). For each scaled species the scaling factors are A and B where x' = Ax + B.

Note 4: In the no-obs run just enter PMF, but in the refined run enter PM_{10} and PMF

Appendix I. CALPOST Input Control Parameters

Table I-1Input Groups in the CALPOST Processor Control File

Group	Description	Applicable
0	Input and output file names	Yes
1	General Run Control Parameters	Yes
2	Visibility Parameters	Yes
3	Output Options	Yes

Table I-2 CALPOST Processor Input Group 1: General Run Control Parameters

Parameter	Default	Value	Comments
METRUN	0	1	1 = Run all met periods in CALPUFF data file
ISYR	None	2001, 2002, 2003	Starting year
ISMO	None	1	Starting month
ISDY	None	1	Starting day
ISHR	None	0	Starting hour
NPER	None	See note 1 below	Number of periods to process
NREP	1	1	Process every hour of data? Yes = 1
ASPEC	None	VISIB	Process species for visibility
ILAYER	1	1	Layer/deposition code; 1 for CALPUFF concentrations
A	0.0	0.0	Scaling factor, slope
B	0.0	0.0	Scaling factor, intercept
LBACK	F	F	Add hourly background concentrations or fluxes
MSOURCE	0	0	Process only total reported contribution
LG	F	F	Process gridded receptors
LD	F	T	Process discrete receptors
LCT	F	F	Process complex terrain receptors
LDRING	F	F	Report receptor ring results
NDRECP	-1	See note 2 below	To select the Class I area's receptors enter *1 after the number of receptors otherwise enter *0
IBGRID	-1	-1	X index of LL corner of receptor grid
JBGRID	-1	-1	Y index of LL corner of receptor grid
IEGRID	-1	-1	X index of UR corner of receptor grid
JEGRID	-1	-1	X index of UR corner of receptor grid
NGONOFF	0	0	Number of gridded receptor rows
NGXRECP	1	0	Exclude specific gridded receptors, Yes = 0

Note 1: Enter 8760 for the years 2001 and 2002, but enter 8748 for the year 2003.

Note 2: CALPOST is to be run for each Class I area assessed.

- The following are the number of receptors for each Class I area being assessed:
  1. Caney Creek = 80
  2. Hercules-Glade = 47
  3. Mingo Wilderness = 80
  4. Sipsey = 148
  5. Upper Buffalo = 72

Table I-3 CALPOST Processor Input Group 2: Species Processing Information

Parameter	Default	Value	Comments
RHMAX	98	95	Maximum RH (%) used in particle growth curve
LVSO4	T	T	Compute light extinction for sulfate?
LVNO3	T	T	Compute light extinction for nitrate?
LVOC	T	T	Compute light extinction for organic carbon?
LVMPC	T	T	Compute light extinction for coarse particles?
LVMPF	T	T	Compute light extinction for fine particles?
LVEC	T	T	Compute light extinction for elemental carbon?
LVBK	T	T	Include background in extinction calculation?
SPECPMC	PMC	PMC	Coarse particulate species
SPECPMF	PMF	PMF	Fine particulate species
EEPMC	0.6	0.6	Extinction efficiency for coarse particulates
EEPMF	1.0	1.0	Extinction efficiency for fine particulates
EEPMCBK	0.6	0.6	Extinction efficiency for coarse part. background
EESO4	3.0	3.0	Extinction efficiency for ammonium sulfate
EENO3	3.0	3.0	Extinction efficiency for ammonium nitrate
EEOC	4.0	4.0	Extinction efficiency for organic carbon
EESOIL	1.0	1.0	Extinction efficiency for soil
EEEC	10.0	10.0	Extinction efficiency for elemental carbon
MVISBK	2	6	Method 6 for background light extinction: Compute extinction from speciated PM measurements. FLAG RH adjustment factor applied to observed & modeled sulfate and nitrate
BEXTBTBK	--	12	Background extinction for MVISBK=1 (1/Mm)
RHFRAC	--	10	Percentage of particles affected by RH
RHFAC	12*value	Depends on Class I Area	Extinction coefficients for modeled and background hygroscopic species computed using EPA (2003) monthly RH adjustment factors
BKSEC	0.02	0.02	Eastern background elemental carbon β_{ext}
BKSO4	0.23	0.23	Eastern background sulfate β_{ext}
BKNO3	0.10	0.10	Eastern background nitrate β_{ext}
BKPMC	3.00	3.00	Eastern background PMC β_{ext}
BKSOC	1.40	1.40	Easter background organic carbon β_{ext}
BKSSOIL	0.50	0.50	Eastern background soil β_{ext}
BKSEC	0.02	0.02	Eastern background elem. β_{ext}
BEXTRAY	10.0	10.0	Extinction due to Rayleigh scattering (1/Mm)

Table I-4 CALPOST Processor Input Group 3: Output Options

Parameter	Default	Value	Comments
LDOC	F	F	Print documentation image
IPRTU	1	3	Print output units ($\mu g/m^3$) for concentrations and ($\mu g/m^2/sec$) for deposition
L1HR	T	F	Report 1 hr averaging times
L3HR	T	F	Report 3 hr averaging times
L24HR	T	T	Report 24 hr averaging times
LRUNL	T	F	Report run-length (annual) averaging times
LT50	T	F	Top 50 table
LTOPN	F	F	Top 'N' table
NTOP	4	4	Number of 'Top-N' values at each receptor
ITOP	1,2,3,4	1,2,3,4	Ranks of 'Top-N' values at each receptor
LEXCD	F	F	Threshold exceedances counts
THRESH1	-1.0	-1.0	Averaging time threshold for 1 hr averages
THRESH3	-1.0	-1.0	Averaging time threshold for 3 hr averages
THRESH24	-1.0	-1.0	Averaging time threshold for 24 hr averages
THRESHN	-1.0	-1.0	Averaging time threshold for NAVG-hr averages
NDAY	0	0	Accumulation period, days
NCOUNT	1	1	Number of exceedances allowed
LECHO	F	F	Echo option
LTIME	F	F	Time series option
LPLT	F	F	Plot file option
LGRD	F	F	Use grid format instead of DATA format
LDEBUG	F	F	Output information for debugging?

Appendix J. Chapter 3 of the CENRAP BART Modeling Guidelines (Tesche, et al, 2005)

3.0 CALPUFF FORMULATION AND IMPLEMENTATION

The RHR relates visibility attenuation to extinction coefficient (b_{ext}) which is a measure of light scattering and absorption due to atmospheric constituents. Values for b_{ext} are estimated using an empirically derived equation which relates the extinction coefficient to relative humidity and the following components of particulate matter mass: (a) sulfates (SO_4); (b) nitrates (NO_3); (c) organic carbon (OC); (d) elemental carbon (EC); (f) particulate matter (IP) ("crustal material"); and (g) coarse mass (CM) (i.e., PM_{10} – $PM_{2.5}$). The BART guidance requires the use of modeled concentrations of these components, together with a "humidity correction factor", to estimate values for b_{ext} on all days within a three year period. These estimates, when compared with naturally occurring background extinction, are used to determine whether a source is causing or contributing to visibility impairment and also to measure the effectiveness of emissions controls on the source aimed at mitigating such effects. EPA notes that secondary particulate matter constitutes an important fraction of $PM_{2.5}$ and that the modeling requirements for secondary and primary particulate matter differ in their need to consider atmospheric chemistry and in the degree of spatial resolution needed for the modeling (EPA, 2001, pg 22).

This chapter introduces the formulation of the CALPUFF modeling system. We summarize the model capabilities as described in the user's manuals (Scire et al., 2000a,b) and discuss the capabilities and limitations of the model. Equipped with this information, states and source operators can identify those situations for which screening and/or source-specific applications of CALPUFF are appropriate.

In most cases, we expect that application of the CALPUFF system will be sufficient to meet the BART Rule requirements. For that subset of conditions requiring advanced methods, Chapter 5 provides details on full-science alternative models and available data bases for BART modeling. Such conditions might include a situation where the default modeling shows that a source just barely causes or contributes to visibility degradation or in negotiations over the final BART determination that weighs technical and economic feasibility against expected air quality benefits. In both situations, a more accurate estimate of a source's impacts may be very important to source operators.

3.1 Original Model Development

The CALPUFF modeling system was originally developed as a component of a three-part modeling system sponsored by the California Air Resources Board (ARB) in the mid-1980s. The ARB sought to develop a new puff-based model, a new grid-based model and an improved meteorological processor that would support application of the two. CALGRID was the urban-scale photochemical grid model resulting from the project (Yamartino et al., 1992) comparable in science and capabilities to the Urban Airshed Model (UAM-IV) (Scheffe and Morris, 1993). The model formulation was aimed at overcoming the deficiencies in EPA's steady-state Gaussian plume models that were routinely used in California for inert and linearly reactive materials (principally SO_2) from elevated point sources. Thus, the CALGRID model was designed to treat the complexities of urban-scale photochemical processes while CALPUFF was formulated to treat the non-steady state transport, diffusion, linear reaction, and deposition of primary pollutants from point sources. CALPUFF was not designed to address photochemical oxidants or and secondary aerosol formation production processes in a scientifically rigorous manner.

In recent years, CALPUFF and its meteorological pre-processor (CALMET) have been used in a range of regulatory modeling studies to address point source issues that include complexities posed by complex terrain, large source-receptor distances, parameterized chemical transformation and deposition, and issues related to Class I visibility impacts. These applications are more complex than the California ARB's non-steady-state, linear chemistry formulation of the mid-1980s.

The CALPUFF modeling system has been adopted by the EPA as a guideline model for source-receptor distances greater than 50 km, and for use on a case-by-case basis in complex flow situations for shorter distances. It was recommended for Class I impact assessments by the FLM Workgroup (FLAG, 2000) and the Interagency Workgroup on Air Quality Modeling (IWAQM) (EPA, 1998). As directed in the BART guidance, CALPUFF is the primary modeling system for screening and source-specific BART applications in the CENRAP region. Thus, examination of the model's formulation provides the context for assessing the extent to which it suitable for simulating the various physical processes and gas-phase, aerosol, and aqueous-phase chemical processes that influences visibility.

3.2 CALPUFF Model Formulation

The CALPUFF user's guide (Scire et al., 2000a) depicts the modeling system as shown in Figure 3-1. CALMET is a diagnostic/interpolation model that provides meteorological inputs to CALPUFF. These fields include hourly-averaged three-dimensional wind and temperature fields and two-dimensional fields of mixing heights and other meteorological parameters. CALMET uses routine surface and aloft meteorological observations and/or three-dimensional output from prognostic numerical models such as MM5 (Grell et al., 1995) or RUC (Benjamin et al., 2004) to construct the meteorological inputs. Other inputs to the air quality program include emissions information, receptor locations, ancillary geophysical information, and estimated concentrations of ambient pollutants that are entrained by the modeled puffs as each is carried downwind. Tables 3-1 and 3-2 summarize the key features of the CALMET/CALPUFF models as described in the user's guides.

Two post-processor routines are included to facilitate cumulative source impacts (POSTUTIL) and estimates of light extinction and visibility attenuation at Class I receptors of interest (CALPOST). In particular, CALPOST contains several options for computing change in extinction and deciviews for visibility assessments while the POSTUTIL postprocessor includes options for summing contributions of individual sources or groups of sources to assess cumulative impacts. POSTUTIL also contains an empirical nitric acid-nitrate chemical equilibrium module to estimate the cumulative effects of ammonia consumption by background sources once the simulation is completed.

3.2.1 Model Concept and Governing Equations

The starting point for the CALPUFF development was the choice of the fundamental reference system of which there are two: Eulerian and Lagrangian. Consistent with the original ARB design criteria, the Lagrangian (moving puff) reference system was chosen for CALPUFF. In the Eulerian approach, the behavior of pollutants is described relative to a fixed coordinate system. The Lagrangian reference frame, in contrast, relates the behavior of pollutants relative to a coordinate system that moves with the average wind. These two approaches yield different mathematical relationships for pollutant concentrations *that are equally valid*. The choice of which approach to adopt depends upon the specific design goals of the modeling system.

The advantages and drawbacks of each approach are thoroughly discussed in the literature (Tesche, 1983; Seinfeld and Pandis, 1998; Jacobson, 1999; Russell and Dennis, 2000). One of the criticisms of early Eulerian grid models was their 'over-dilution' of point source emissions into the fixed grid cells; but for the past twenty years, this limitation has been overcome through with the development of sub-grid-scale, plume-in-grid algorithms (Seigneur, et al., 1981; Godowitch, 2004; Karamchandani et al., 2005; Emery and Yarwood, 2005) and the use of multi-scale nested grids (Russell and Dennis, 2000). While the Lagrangian approach is conceptually simple, flexible, and computationally inexpensive, the governing equations are not directly applicable to situations involving non-linear chemical reactions (Seinfeld and Pandis, (1998) and it is awkward to handle a large number of sources realistically.

3.2.2 Transport and Dispersion

Adopting the Lagrangian concept, CALPUFF simulates the transport, dispersion, linear chemical transformation, and deposition of individual puffs carried downwind by the three-dimensional fields generated by CALMET. The model's implementation follows puffs from the near source region (a few tens of meters) to hundreds of kilometers downwind. Its puff-based formulation, in conjunction with three-dimensional hourly meteorological data, allow CALPUFF to simulate the effects of time- and space-varying meteorological conditions on pollutants emitted from a variety of source types. The major features and options of the CALPUFF model are summarized below:

<ins>*Building Downwash:*</ins> The Huber-Snyder and Schulman-Scire downwash models are both incorporated into CALPUFF. An option is provided to use either model for all stacks, or make the choice on a stack-by-stack and wind sector-by-wind sector basis. Both

algorithms have been implemented in such a way as to allow the use of wind direction specific building dimensions. The PRIME building downwash model (Schulman et al., 2000) is also included in CALPUFF as an option.

Dispersion Coefficients: Turbulent dispersion in CALPUFF is treated with the K-theory (flux-gradient) closure scheme, defined for a Lagrangian frame of reference. Several options are provided in CALPUFF for the computation of dispersion coefficients, including the use of turbulence measurements (σ_v and σ_w), the use of similarity theory to estimate σ_v and σ_w from modeled surface heat and momentum fluxes, or the use of Pasquill-Gifford (PG) or McElroy-Pooler (MP) dispersion coefficients, or dispersion equations based on the CTDM. Options are provided to apply an averaging time correction or surface roughness length adjustments to the PG coefficients. Recently, the EPA AERMOD dispersion parameters have been included in CALPUFF and are used regularly.

Puff Sampling Functions: Puff sampling routines are included in CALPUFF to address computational difficulties encountered when applying a puff model to near-field releases. For near-field applications during rapidly-varying meteorological conditions, an elongated puff (slug) sampling function may be used. An integrated puff approach may be used during less demanding conditions. Both techniques reproduce continuous plume results under the appropriate steady state conditions.

Wind Shear Effects: A key underpinning of the Lagrangian concept is that the modeled puffs retain their identity over the time- and spatial-scale associated with the effects the model is attempting to predict (i.e., visibility impairment at 200 km or beyond) While discrete puffs emitted from a source retain their physical integrity for a period of time, at some point the action of horizontal and vertical variations in wind speed and direction (i.e. 'wind shear') shred the puff into multiple elements. These new puff parcels, composed of remnants of the old puff, continue to be diffused and dispersed by the wind. The point where significant puff shredding occurs is difficult to define since it depends substantially upon the complexity of the meteorological conditions and the underlying terrain. But when shredding occurs, the Lagrangian concept in CALPUFF breaks down. By ignoring puff shredding (i.e., by keeping puffs intact), the model will systematically over-predict pollutant concentrations.

To deal with this conceptual limitation, CALPUFF contains an optional puff splitting algorithm to simulate vertical wind shear effects across individual puffs. Differential rates of dispersion and transport among the "new" puffs generated from the original, well-mixed puff act to increase the effective rate of horizontal spread of the material as would be expected in the real atmosphere. Puffs may also be split in the horizontal when the puff size becomes large relative to the grid size to account for wind shear across the puffs. Detailed guidance on when and how the puff-splitting algorithm should be used and actual verification studies demonstrating that the technique operates as intended are not discussed in the model documentation or presented in the science literature.

<u>Complex Terrain:</u> Effects of complex terrain on puff transport are derived from the CALMET winds. In addition, puff-terrain interactions at gridded and discrete receptor locations are simulated using one of two algorithms that modify the puff-height (either that of ISCST3 or a general "plume path coefficient" adjustment), or an algorithm that simulates enhanced vertical dispersion derived from the weakly-stratified flow and dispersion module of the Complex Terrain Dispersion Model (CTDMPLUS) (Perry et al., 1989). The puff-height adjustment algorithms rely on the receptor elevation (relative to the elevation at the source) and the height of the puff above the surface. The enhanced dispersion adjustment relies on the slope of the gridded terrain in the direction of transport during the time step.

<u>Subgrid Scale Complex Terrain (CTSG):</u> An optional module, CTSG treats terrain features that are not resolved by the gridded terrain field, and is based on the CTDMPLUS (Perry et al., 1989). Plume impingement on subgrid-scale hills is evaluated at the CTSG subgroup of receptors using a dividing streamline height (H_d) to determine which pollutant material is deflected around the sides of a hill (below H_d) and which material is advected over the hill (above H_d). The local flow (near the feature) used to define H_d is taken from the gridded CALMET fields. As in CTDMPLUS, each feature is modeled in isolation with its own set of receptors.

<u>Overwater and Coastal Interaction Effects</u>: The CALMET processor contains overwater and overland boundary layer parameterizations allowing certain of the effects of water bodies on plume transport, dispersion, and deposition to be estimated. In a sense, CALPUFF operates as a hybrid model, by utilizing gridded fields of meteorology and dispersion conditions as well as grid-based descriptions of underlying land use. This includes the abrupt changes that occur at the coastline of a major body of water.

<u>Dry Deposition</u>: A resistance model is used for the computation of dry deposition rates of gases and particulate matter as a function of geophysical parameters, meteorological conditions, and pollutant species. For particles, source-specific mass distributions may be provided for use in the resistance model. Of particular interest for BART analyses is the ability to separately model the deposition of fine particulate matter (< 2.5 μm diameter) from coarse particulate matter (2.5-10 μm diameter).

<u>Wet Deposition</u>: An empirical scavenging coefficient approach is used to compute the depletion and wet deposition fluxes due to precipitation scavenging. The scavenging coefficients are specified as a function of the pollutant and precipitation type (i.e., frozen vs. liquid precipitation).

3.2.3 Primary Particulates

CALPUFF is designed to simulate PM_{10} or $PM_{2.5}$ or other user defined size distributions of particles. The smaller the particles, the more they disperse like an inert gas. In most cases, the dispersion of inert $PM_{2.5}$ particles will differ only slightly from that of an inert gas. A key primary $PM_{2.5}$ emission from coal-fired electric generating units (EGUs) of relevance to visibility calculations is particulate sulfate. Although primary sulfate emissions account for only a small fraction of the total sulfur emissions from such sources, it is appropriate to include their effect if reasonable estimates of primary sulfate emissions from the source are available. Treating primary sulfate emissions is likely to be most important at short distances from the stack before significant SO_2 to secondary sulfate conversion has taken place.

3.2.4 Gas-Phase Chemistry

Chemical reactions in the gas-phase play an important role in secondary aerosol formation by generating radical concentrations (e.g., the hydroxyl radical). These radical species oxidize SO_2 and NOx, providing the precursors to aqueous–phase chemistry (i.e., chemistry in liquid water droplets) that convert SO_2 to sulfate (e.g., H_2O_2 and O_3), and form condensable gases from some volatile organic compounds (VOCs) that can then condense into particulate secondary organic aerosols (SOA). The levels of NOx, VOC, and O_3 concentrations along with the reactivity of the VOCs, sunlight, temperature, and water vapor are all key variables that influence the radical cycle and consequent sulfate and nitrate formation rates.

CALPUFF neglects realistic gas-phase processes entirely. The chemistry in CALPUFF parameterizes chemical transformation effects using five species (SO_2, $SO_4^=$, NO_x, HNO_3, and NO_3^-) via a set of user-specified, diurnally-varying transformation rates. The model estimates secondary fine particulate matter (sulfate and nitrate) from emissions of gas-phase SO_2 and NO_x. Rather than simulating important non-linear gas phase oxidant chemistry, the model employs a user-supplied hourly ozone concentration as a surrogate for the hydroxyl radical and other oxidizing radical species. Ambient ammonia concentrations are also a user input along with temperature and relative humidity.

Although simplifications of photochemistry have been attempted in the past, correct representation of the gas-phase photochemistry and the radical cycles are critically important in order to properly characterize sulfate and nitrate formation in the real atmosphere. Seigneur et al., (2000) demonstrated this fact in their evaluation of full-science representations of photochemistry against simplified representations (but more advanced than CALPUFF). They concluded that simplified linearized transformation schemes are inadequate for describing sulfate and nitrate formation processes:

> “These results indicate that the accurate prediction of source-receptor relationships for $PM_{2.5}$ requires a comprehensive treatment of $PM_{2.5}$ formation from gaseous precursors for the secondary components of $PM_{2.5}$ and a spatially resolved treatment of transport processes for primary $PM_{2.5}$. Simplified treatments of either atmospheric chemistry or transport are appropriate only when the secondary or primary components of $PM_{2.5}$, respectively, are not significant. Therefore, the development of source-receptor relationships for $PM_{2.5}$ should be based on air quality models that provide comprehensive descriptions of atmospheric chemistry and transport.”

Morris et al., (1998) also compared the sulfate and nitrate particulate estimates from a comprehensive full-science regional model with those from a model incorporating a simplified empirical chemical mechanism developed in a manner similar to the mechanism in CALPUFF. Evaluating the full-science and empirical chemistry models against observed concentrations, Morris and co-workers concluded:

> "Given the importance of the radical cycle for determining secondary PM formation rates, it appears that empirical gas-phase algorithms are inadequate for determining secondary PM formation."

The uncertainty and potential biases introduced into the CALPUFF visibility estimates due to neglect of gas phase oxidant chemistry remain unknown.

3.2.5 Aerosol Chemistry

Formation of secondary fine particulate matter (e. g., nitrates, sulfates, organic aerosols) in point source plumes is strongly dependent on the rate of mixing with ambient (background) air and the chemical composition of this background. The rates of oxidation of sulfur dioxide (SO_2) and nitrogen dioxide (NO_2) to sulfate and nitric acid can be very different within a power plant or industrial plume compared to that in the background air (Gillani and Godowitch, 1999; Karamchandani et al., 2000). Similarly, the formation of secondary organic aerosols from emitted VOCs and those from other anthropogenic and biogenic sources, adds yet another pathway in the formation of visibility-impairing aerosols. The presence of atmospheric ammonia introduces further nonlinearities into the gas phase and aerosol reactions. Accordingly, for a model to realistically simulate the production of secondary particulate sulfate, nitrate, and organic aerosols from a potential BART source, the mixing processes and chemical reactions within and outside of the plume must be treated realistically. If the chemical interactions between these two fundamentally different and interactive chemical environments are overly-simplified or neglected altogether, the ability of the model to correctly calculate plume concentrations, deposition, or visibility impacts is lost.

Sulfate and Nitrate Formation. Two SO_2 and NOx chemical transformation schemes are available in CALPUFF: the MESOPUFF-II algorithm (Scire et al., 1983; Atkinson et al., 1982) and the RIVAD algorithm (Latimer et al., 1986). These algorithms calculate sulfate and nitrate formation rates based on the puff concentrations, background environmental parameters provided by CALMET, and background ozone and ammonia concentrations provided as input by the user. SOA particulates are not treated by either mechanism. The parameters used are as follows (note that each method does not use all of these parameters).

Puff Average Concentrations (from CALPUFF)

- NOx concentration
- SO_2 concentration

Environmental Parameters (from CALMET)

- Temperature
- Surface Relative Humidity (RH)
- Atmospheric Stability
- Solar Radiation

Background Concentrations (User Input)

- Ozone (O_3)
- Ammonia (NH_3)

The MESOPUFF-II chemical transformation scheme is EPA's recommended approach for Class I area impact assessment (IWAQM, 1998). It entails pathways for five active pollutants (SO_2, SO_4, NOx, HNO_3, and NO_3) as follows:

$$SO_2 \xrightarrow{k_1} SO_4$$

$$NOx \xrightarrow{k_2} HNO_3\ (+RNO_3)$$

$$NOx \xrightarrow{k_3} HNO_3$$

$$HNO_3\ (g) \overset{NH_3}{\leftrightarrow} NO_3\ (PM)$$

where,

SO_2 is the puff average sulfur dioxide concentration;
NOx is the puff average oxides of nitrogen concentrations;
SO_4 is sulfate concentrations formed from the SO_2;
HNO_3 is the nitric acid formed from the NOx;
NO_3 is the particulate nitrate that is in equilibrium with the nitric acid; and
NH_3 is the background ammonia concentration.

Daytime Rates

$k_1 = 36 \text{ x } R^{0.55} \text{ x } [O_3]^{0.71} \text{ x } S^{-1.29} + k_{1(aq)}$

$k_{1(aq)} = 3 \text{ x } 10^{-8} \text{ x } RH^4$ (added to k_1 above during the day)

$k_2 = 1206 \text{ x } [O_3]^{1.5} \text{ x } S^{-1.41} \text{ x } [NOx]^{-0.33}$

$k_3 = 1261 \text{ x } [O_3]^{1.45} \text{ x } S^{-1.34} \text{ x } [NOx]^{-0.12}$

Nighttime Rates

k_1 = 0.20 (%/hr)
k_2 = 0.00 (%/hr)
k_3 = 2.00 (%/hr)

with,

k_1	is the SO_2 to SO_4 gas-phase transformation rate (%/hr)
$k_{1(aq)}$	is the SO_2 to SO_4 aqueous-phase transformation rate (%/hr)
k_2	is the NOx to HNO_3+RNO_3 transformation rate (%/hr)
k_3	is the NOx to HNO_3 (only) transformation rate (%/hr)
S	is the stability index ranging from 2 to 6 (PGT class A&B=2, C=3, D=4, E=5, F=6)
R	is the total solar radiation intensity (kw/m^2)
RH	is the relative humidity (%)
$[O_3]$	is the user provided background ozone concentrations (ppm)
[NOx]	is the plume average NOx concentration (ppm)
NH_3	is the user provided background ammonia concentrations

Daytime chemical transformations are based on statistically analyzed hourly transformation rates (Scire et al., 1983) obtained from box model simulations using the Atkinson et al., (1982) photochemical mechanism. In this scheme, gas-phase oxidation of SO_2 and NOx depends on the hydroxyl (OH) radical concentrations for which background ozone, solar intensity (R), and stability index are used as surrogates. At night, OH concentrations are much lower and default SO_2 and NOx oxidation rates of 0.2 %/hr and 2.0 %/hr are assumed. The $k_{1(aq)}$ sulfate formation rate is added to the k_1 rate during the day as a surrogate for aqueous-phase sulfate formation which begins to assume importance above approximately 50% RH (~0.2 %/hr sulfate formation rate) and peaks at 100% RH (3%/hr sulfate formation rate).

The sulfate and nitrate formation rate equations used in the MESOPUFF II scheme were originally generated by developing regression equations for a few key variables on the results of 144 box model simulations that used the 1982 photochemical mechanism of Atkinson et al. These box model simulations varied ambient temperature, ozone concentration, sunlight intensity, VOC concentrations, atmospheric stability, and plume NOx concentrations as shown in Table 3-1. The actual environmental conditions used to generate the sulfate and nitrate transformation equations were extremely limited. For example, the transformation rates did not cover temperatures below 10 deg C (50 deg F) or cleaner rural atmospheric conditions with VOC concentrations less than 50 ppbC.

The CALPUFF MESOPUFF-II chemistry clearly neglects several environmental parameters and chemical processes that are important in simulating sulfate and nitrate formation in NO_X/SO_2 emissions source plumes. In many cases these deficiencies lead to an overestimation bias of the source's sulfate and nitrate impacts. Factors that lead such a bias include:

> Lack of Temperature Effects: Photochemistry is known to be highly temperature sensitive, as evidenced by the fact that elevated ozone concentrations tend to occur on hot summer days. Lower temperatures produce lower OH and other radical concentrations and consequently lower sulfate and nitrate formation rates. The CALPUFF sulfate and nitrate formation rates, however, do not adequately incorporate temperature effects. The MESOPUFF-II chemical transformation algorithm was developed under conditions with a minimum temperature of only

10° C (50° F). Thus, under conditions colder than 10° C, CALPUFF will overpredict sulfate and nitrate formation rates and impacts. CALPUFF typically estimates maximum sulfate and visibility impacts during the late fall/early spring and winter months; these are the same months when the CALPUFF overestimation bias from not considering temperature effects will be greatest. In addition, under colder temperatures, NOx will be converted to peroxyacetyl nitrate (PAN) so that the NOx is no longer available to be converted to nitrate. Since the CALPUFF chemistry ignores the PAN sink for NOx, it will systematically overpredict nitrate impacts.

Effects of NOx Emissions on Sulfate Chemistry: Downwind of a point source with significant NOx/SO_2 emissions, high NOx and SO_2 concentrations co-exist. Under high NOx concentrations, radical concentrations are greatly reduced, resulting in very low ozone, sulfate, and nitrate formation rates. This is due to the NOx inhibition effect on photochemistry whereby: (1) the titration of NO with ozone eliminates ozone and its source as a radical generator; and (2) the high NO_2 concentrations eliminate the OH radical via the NO_2 + OH reaction thereby effectively shutting down photochemistry. Thus, in a NOx/SO_2 point source plume near the source, there will be very low OH radical and ozone concentrations and consequently very low sulfate and nitrate formation. Since the simple MESOPUFF-II transformation equations cannot account for the NOx effect on the sulfate formation, CALPUFF will tend to over-predict sulfate formation rate in a NOx/SO_2 point source plume near the source, which in turn leads to overstating the sulfate formation rate. Because NOx/SO_2 point sources are typically buoyant, they are frequently be emitted aloft in a stable layer where the high NOx concentrations and inhibited sulfate and nitrate formation rates could persist 100 km or more downwind.

Aqueous-Phase Sulfate Formation Algorithm. CALPUFF's MESOPUFF-II chemistry treats aqueous-phase sulfate formation solely as a function of relative humidity (RH), which actually has no direct affect on aqueous-phase sulfate formation chemistry. The CALPUFF MESOPUFF-II aqueous-phase sulfate formation rate ranges from values of approximately 0.2 %/hr at 50% RH to 3.0 %/hr at 100% RH. Relative humidity (RH) is a measure of the content of water vapor in the atmosphere. However, in reality aqueous-phase sulfate formation will depend on the amount of atmospheric liquid water content (LWC) in cloud or fog droplets, the pH of the water droplets, and the level of H_2O_2, ozone, and SO_2 concentrations. Accordingly, in the atmosphere, aqueous-phase sulfate formation chemistry is not affected by RH. Thus, the CALPUFF aqueous-phase chemistry parameterization is incorrect. Although under conditions of clouds and fog there will be high RH, the occurrence of high RH with very little or no clouds or fog can be quite frequent.

In a liquid water droplet, the reaction of SO_2 with H_2O_2 to form sulfate is essentially instantaneous and is usually limited by the amount of H_2O_2 present (i.e., oxidant limited) for a NOx/SO_2 point source. Once the H_2O_2 is reacted away within the water droplet, sulfate formation via this pathway slows to the rate of H_2O_2 formation, which would be extremely slow to nonexistent in a large point source plume due to the scavenging of radicals by the high NOx concentrations. This introduces an inaccurate representation of sulfate formation in CALPUFF that creates uncertainties and bias in modeled visibility impacts. Whether this uncertainty results in an under- or overestimate of sulfate formation is difficult to determine since the approach is scientifically invalid. Under conditions of high RH and little clouds or little plume interaction with clouds, it will clearly overstate sulfate formation. However, under conditions of cloudy conditions with available photochemical oxidants (i.e., H_2O_2 and O_3) and a dilute NOx/Sox point source plume, it may understate sulfate formation. Near large NOx/SO_2 point source where the elevated NOx concentrations scavenge and limit photochemical oxidants, the MESOPUFF-II algorithm will likely overstates sulfate formation.

Thus, the CALPUFF aerosol chemistry fails to account for many environmental parameters that are necessary to simulate sulfate and nitrate formation rates, including VOCs and their reactivity, temperature, liquid water content, and NOx concentrations. In their evaluations against full-science PM models and observations, Seigneur et al., (2000) and Morris et al., (1998) both independently found that the empirical chemistry modules, such as employed by CALPUFF, are inadequate for estimating sulfate and nitrate formation. These findings are supported by EPA's $PM_{2.5}$ and Regional Haze SIP modeling guidance (EPA, 2001) that recommends against using Lagrangian models such as CALPUFF for simulating secondary PM.

From the foregoing, it is clear that the CALPUFF chemical transformation algorithms neglect important chemical processes necessary to accurately estimate the sulfate and nitrate impacts due to SO_2 and NO_X emissions. Given that EPA recommends the model for BART determinations, a key question is "What is the influence of the simplified chemistry on modeled estimates of visibility impacts from BART sources? In some cases, the inadequacies in the CALPUFF chemistry algorithms may simply introduce broader uncertainties into the calculation of estimated sulfate and nitrate impacts. In many cases, however, the simplifications made in the CALPUFF description of chemical processes result in a systematic bias in the estimated concentrations and visibility impacts due to SO_2 and NO_X emissions sources. For large point sources that emit SO_2 and NOx emissions, such as EGUs, petrochemical process heaters, cement plant kilns, etc., many of the limitations in the CALPUFF MESOPUFF-II SO_2 and NOx transformation algorithms would result in an overestimation bias. While models that are systematically biased high (i.e., over-predict impacts) may be appealing to regulatory decision-makers because they are 'conservative', the overprediction tendency may well lead to unwarranted and excessive control of emissions from some sources. Thus, the tradeoff between simplicity and conservativism on the one hand and technical credibility and unbiased answers on the other is a key element in the negotiation of modeling protocols developed by the states or source operators.

3.2.6 Surface Removal

An especially important contributor to particulate concentrations is the rate of deposition to the surface. $PM_{2.5}$ particles, which have a mass median diameter around 0.5

µm, have an average net deposition velocity of about 1 cm/min (or about 14 m/day) and thus the deposition of fine particles is not usually significant except for ground-level emissions. On the other hand, coarse particles (those PM_{10} particles larger than $PM_{2.5}$) have an average deposition velocity of more than 1 m/min (or 1440 m/day), which is significant, even for emissions from elevated stacks.

CALPUFF includes parametric representations of particle and gas deposition in terms of atmospheric, deposition layer, and vegetation layer "resistances" and, for particles, the gravitational settling speed. Gravitational settling, which is of particular importance for the coarse fraction of PM_{10}, is accounted for in the calculation of the deposition velocity. Effects of inertial impaction (important for the upper part of the PM_{10} distribution) and Brownian motion (important for small, sub-micron particles) and wet scavenging are also addressed. The BART guidance recommends that fine particulate matter (less than 2.5 µm diameter), which has higher light extinction efficiency than coarse particulate matter (2.5-10 µm diameters), should be treated separately in the model. CALPUFF allows for user-specified size categories to be treated as separate species, which includes calculating size-specific dry deposition velocities for each size category.

3.3 CALMET Meteorological Preprocessor

The CALMET meteorological model consists of a diagnostic wind field module and micrometeorological modules for over-water and overland boundary layers. When modeling a large geographical area such as the CENRAP domain, the user has the option to use a Lambert Conformal Projection coordinate system to account for Earth's curvature. The major features and options of the meteorological model are summarized in Table 3-1. The techniques used in the CALMET model are briefly described below.

3.3.1 Boundary Layer Modules

The CALMET processor contains two boundary layer modules for application to overland and overwater grid cells.

Overland Boundary Layer Module: Over land surfaces, the energy balance method of Holtslag and van Ulden (1983) is used to compute hourly gridded fields of the sensible heat flux, surface friction velocity, Monin-Obukhov length, and convective velocity scale. Mixing heights are determined from the computed hourly surface heat fluxes and observed temperature soundings using a modified Carson (1973) method based on Maul (1980). The module also determines gridded fields of PGT stability class and hourly precipitation rates.

Overwater Boundary Layer Module: The aerodynamic and thermal properties of water surfaces suggest that a different method is needed for estimating boundary layer parameters in the marine environment. A profile technique, using air-sea temperature differences, is used in CALMET to compute the micro-meteorological parameters in the marine boundary layer. An upwind-looking spatial averaging scheme is optionally applied to the mixing heights and three-dimensional temperature fields in order to account for important advective effects.

3.3.2 CALMET Diagnostic Wind Field Module

The CALMET wind model was constructed from two other meteorological models used in California in the late 1970s. One was the California Institute of Technology (CIT) mass consistent interpolation model described by Goodin et al., (1980). The other was the Complex Terrain Wind Model (CTWM) developed at Systems Applications, Inc. (Tesche and Yocke, 1978; Yocke and Liu, 1978). The CTWM terrain adjustments used to modify the flow fields were assembled in the 1970s as part of research into fire spread and avalanche forecasting in mountainous regions of California. Various heuristic algorithms were developed to approximate down slope drainage flows, terrain blocking and channeling (Geiger, 1965), thermal heat islands (Stern and Malkus, 1953), surface friction retardation, capping by an elevated inversion and so on. These algorithms were based on empirical studies in wind tunnels, numerical modeling experiments, and field studies in the Alps, some dating back to the 1930s (Defant, 1933). Later work by Tesche et al., (1986), Kessler et al., (1987) and Douglas and Kessler (1988) integrated the CIT and CTWM modeling system into a single meteorological model that included algorithms to blend observational data with prognostic meteorological model output. The combined model was used extensively for urban-scale ozone studies throughout the U.S. prior to the switch to MM5 as the preferred meteorological model for SIP studies in the mid-1990s.

The CALMET model development incorporated the main features of the CTWM and CIT wind model and significantly updated the physical parameterizations and improved model input/output (I/O) schemes (Scire et al., 2000a). Today, CALMET uses the CTWM two-step approach to the computation of the wind fields. In the first step, an ‘initial-guess’ wind field is constructed and then adjusted to approximate the kinematic effects of terrain, slope flows, and terrain blocking. Currently, the gridded MM5 field is used as the initial guess prior to terrain-perturbation. The second step consists of an objective analysis procedure to blend the MM5 field with observational data to produce a final wind field. This introduction of observational data in the second step of the CALMET wind field development is optional. It is also possible to run the model in “no observations” (No-Obs) mode, which involves the use only of MM5 gridded data for the initial guess field followed by fine-scale terrain adjustments on the scale of the CALMET domain.

Normally, the CALMET computational domain is specified to be at smaller grid spacing than the MM5 dataset used to initialize the initial guess field. For example, 36/12 km MM5 data sets available for 2000-2003 over the CENRAP domain have been used to develop the 6 km CALMET grids shown in Figures 5-1 through 5-4.

The current thermal, kinematic, and dynamic effects parameterized in CALMET, used in the first step of the windfield development, are as follows:

Kinematic Effects of Terrain: The CTWM algorithms for kinematic effects (Liu and Yocke, 1980) is used to evaluate the influence of the terrain on the wind field. The initial guess field winds are used to compute a terrain-forced vertical velocity, subject to an exponential, stability-dependent decay function. The effects of terrain on the horizontal wind components are evaluated by applying a divergence-minimization scheme to the initial guess wind field. The divergence minimization scheme is applied iteratively until the three-dimensional divergence is less than a threshold value.

Slope Flows: The original slope flow algorithm (Defant, 1933) has been upgraded (Scire and Robe, 1997) based on the shooting flow algorithm of Mahrt (1982). This scheme includes both advective-gravity and equilibrium flow regimes. At night, the slope flow model parameterizes the flow down the sides of the valley walls into the floor of the valley, and during the day, upslope flows are parameterized. The magnitude of the slope flow depends on the local surface sensible heat flux and local terrain gradients. The slope flow wind components are added to the wind field adjusted for kinematic effects.

Blocking Effects: The thermodynamic blocking effects of terrain on the wind flow are parameterized in terms of the local Froude number (Allwine and Whiteman, 1985). If the Froude number at a particular grid point is less than a critical value and the wind has an uphill component, the wind direction is adjusted to be tangent to the terrain.

3.4 Estimation of Regional Haze Contributions

The default procedure for quantifying visibility impacts is described in several documents (IWAQM, 1998; FLAG, 2000). Implementation of these procedures in CALPUFF is described in the user's documentation (Scire et al., 2000b). Generally, 'visibility' may be quantified either by visual range (the greatest distance that a large object can be seen) or by the light extinction coefficient, which is a measure of the light attenuation per unit distance due to scattering and absorption by gases and particles. Visibility is impaired when light is scattered in and out of the line of sight and by light absorbed along the line of sight. The light extinction coefficient (b_{ext}) considers light extinction by scattering (b_{scat}) and absorption (b_{abs}):

$$b_{ext} = b_{scat} + b_{abs}$$

The scattering components of extinction (b_{scat}) are represented by light scattering due to air molecules (i.e., Rayleigh scattering, $b_{rayleigh}$) and light scattering due to particles, b_{sp}. The absorption components of extinction (b_{abs}) include light absorption due to gases (b_{ag}) and particles (b_{ap}). Furthermore, particle scattering, b_{sp}, can be expressed by its components:

$$b_{sp} = b_{SO4} + b_{NO3} + b_{OC} + b_{SOIL} + b_{Coarse}$$

where the chemical species and soot scattering coefficients are given as:

$b_{SO4} = 3\ [(NH_4)_2SO_4]\ f(RH)$

$b_{NO3} = 3\ [NH_4NO_3]f(RH)$

$b_{OC} = 4\ [OC]$

$b_{SOIL} = [Soil]$

$b_{Coarse} = 0.6\ [Coarse\ Mass]$

$b_{ap} = 10\ [EC]$

The numeric coefficient at the beginning of each equation is the dry scattering or absorption efficiency in meters-squared per gram. The f(RH) term is a monthly-average relative humidity adjustment factor. The terms in the brackets are the estimated concentrations fro CALPUFF (or other model) in micrograms per cubic meter (µg/m^3).

Finally, the total atmospheric extinction is estimated as:

$$b_{ext} = b_{SO4} + b_{NO3} + b_{OC} + b_{SOIL} + b_{Coarse} + b_{ap} + b_{rayleigh}$$

or, substituting in the above terms,

$$b_{ext} = 3\ f(RH)\ [(NH_4)_2SO_4] + 3\ f(RH)\ [NH_4NO_3] + 4[OC] + 1[Soil] + 0.6[Coarse\ Mass] + 10[EC] + b_{Ray} \qquad (3\text{-}1)$$

This is the so-called IMPROVE extinction equation currently recommended by EPA (2003). Note that the sulfate (SO_4) and nitrate (NO_3) components are hygroscopic because their extinction coefficients depend upon relative humidity. The concentrations, in square brackets, are in µg/m^3 and b_{ext} is in units of Mm^{-1}. The Rayleigh scattering term (b_{Ray}) has a default value of 10 Mm^{-1}, as recommended in EPA guidance for tracking reasonable progress (EPA, 2003a). The effect of relative humidity variability on the extinction coefficients for SO_4 and NO_3 can be estimated in several ways, but following the EPA BART guidelines, the Class I area-specific monthly f(RH) values shown in Table 6-1 should be used.

Modeled ground level concentrations of each of the above visibility impairing pollutants are used with the IMPROVE equation to deduce the extinction coefficient. The change in visibility (measured in terms of ‘deciviews’) is compared against background conditions. The delta-deciview, Δdv, value is calculated from the source's contribution to extinction, b_{source}, and background extinction, $b_{background}$, as follows:

$$\Delta dv = 10\ ln((b_{background} + b_{source}) / b_{background})$$

The impact of a source is determined by comparing the Δdv, or haze index (HI), for estimated natural background conditions with the impact of the source and without the impact of the source. *If the Δdv value is greater than the 0.5 dv threshold the source is said to contribute to visibility impairment and is thus subject to BART controls.*

CALPOST uses a previous IMPROVE *f(RH)* curve (FLAG, 2000) which differs slightly from the *f(RH)* now used by IMPROVE and EPA (2003), mainly at high relative humidity. Also, CALPOST sets the maximum *RH* at 98% by default (although the user can change it), while the EPA's guidance now caps it at 95% (easily modified in the CALPUFF input file).

For regional haze light extinction calculations, use of a plume-simulating model such as CALPUFF is appropriate only when the plume is sufficiently diffuse that it is not visually discernible as a plume *per se*, but nevertheless its presence could alter the visibility through the background haze. The IWAQM Phase 2 report states that such conditions occur starting 30 to 50 km from a source. This is consistent with the BART guidance recommendation for using CALPUFF for source-receptor distances greater than 50 km. But, CALPUFF is also recommended by EPA as an option that can be considered for shorter transport distances when the plume may in fact be discernible from the background haze.

Apart from the chemistry issues discussed previously, there do not appear to be any major reasons why CALPUFF cannot be used for even shorter transport distances than 30 km, as long as the scale of the plume is larger than the scale of the output grid so that the maximum concentrations and the width of the plume are adequately represented and so that the sub-grid details of plume structure can be ignored when estimating effects on light extinction. The standard 1-km output grid that has been established for Class I area analyses should serve down to source-receptor distances somewhat under 30 km; how much closer than 30 km will depend on the topography and meteorology of the area and should be evaluated on a case-by-case basis with individual CENRAP State modelers. (For reference, the width of a Gaussian plume, $2\sigma_y$, is roughly 1 km after 10 km of travel distance, assuming Pasquill-Gifford dispersion rates under neutral conditions.)

3.4.1 CALPOST Methods

Calculation of the impact of the simulated plume particulate matter component concentrations on light extinction is carried out in the CALPOST postprocessor. For BART applications, this processor is of considerable importance.

CALPOST is used to process the CALPUFF outputs, producing tabulations that summarize the results of the simulations, identifying for example, the highest and second-highest hourly-average concentrations at each receptor. When performing visibility-related modeling, CALPOST uses concentrations from CALPUFF to compute light extinction and related measures of visibility (deciviews), reporting these for a 24-hour averaging time. The CALPOST processor contains several options for evaluating visibility impacts, including the method described in the BART guidance, which uses monthly average relative humidity values. CALPOST contains implementations of the IWAQM-recommended and FLAG-recommended visibility techniques and additional options to evaluate the impact of natural weather events (fog, rain and snow) on background visibility and visibility impacts from modeled sources. CALPOST uses Equation 3-1 to calculate the extinction increment due to the source of interest and provides various methods for estimating the background extinction against which the increment is compared in terms of percent or deciviews.

For background extinction, the CALPOST processor contains seven techniques for computing the change in light extinction due to a source or group of sources (i.e., Methods 1 through 7). These are usually reported as 24-hour average values, consistent with EPA and FLM guidance. In addition, there are two techniques for computing the 24-hour average change in extinction (i.e., as the ratio of 24-hour average extinctions, or as the average of 24-hour ratios). Method 2 is the current default, recommended by both IWAQM (EPA, 1998) and FLAG (2000) for source-specific. Method 6 is recommended by EPA's BART guidance (70 FR 39162).

In Method 2, user-specified, speciated monthly concentration values are used to describe the background. When applied to natural conditions, for which EPA's default natural conditions concentrations are annual averages, the same component concentrations would have to be used throughout the year (unless potential refinements to those default values resulted in concentrations that vary during the year). Hourly background extinction is then calculated using these concentrations and hourly, site-specific *f(RH)* from a 1993 IWAQM curve or, optionally, the EPA regional haze f(RH) curve.[2] Again the *RH* is capped at either 98% (default) or a user-selected value (most commonly at 95%).

Method 6 is similar to Method 2, except monthly f(RH) values (e.g., EPA's monthly climatologically representative values) are used in place of hourly values for calculating both the extinction impact of the source emissions and the background conditions extinction. Hourly source impacts, with the effect on extinction due to sulfates and nitrates calculated using the monthly-average relative humidity in f(RH), are compared against the monthly default natural background concentrations. Thus the monthly-averaged relative humidity is applied to the hygroscopic components (i.e., sulfate and nitrate) of both the source impact and the background extinction with Method 6.

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[2] Note that the hourly-varying natural background extinction here is not consistent with that prescribed by the EPA's natural conditions guidance (EPA, 2003b), for which a "climatologically-representative" f(RH) that only varies monthly is to be used. Method 6 uses these monthly average humidity values.

3.4.2 POSTUTIL

The POSTUTIL processor allows the cumulative impacts of multiple sources from different simulations to be summed, including computing the difference between two sets of predicted impacts (useful for evaluating the benefits of BART controls). It also contains a chemistry module to evaluate the equilibrium relationship between nitric acid and nitrate aerosols. This capability allows the potential non-linear effects of ammonia scavenging by background sulfate and nitrate sources to be approximated in the formation of nitrate from an individual source. The processor can compute the impacts of individual sources or groups of sources on sulfur and nitrogen deposition into aquatic, forest and coastal ecosystems, thereby allowing changes in deposition fluxes resulting from changes in emissions to be quantified.

The POSTUTIL processor attempts to overcome the bias introduced when CALPUFF assumes that the full background ammonia concentration is entrained into each discrete puff. For a single puff, this may be satisfactory, but the model overestimates the production of ammonium nitrate when multiple puffs co-exist and overlap. The POSTUTIL processor re-partitions the ammonia and nitric acid concentrations to conform to the ammonia-limiting processes influencing nitrate formation. Though based on recognized science, this approximate post-processing method is fundamentally dependent on reliable estimates of ambient NH_3 at the Class I receptor of interest.

3.4.3 Refined Extinction and Background Visibility Estimates

EPA, the IMPROVE Steering Committee, and the RPOs are evaluating whether refinements are warranted to the methods recommended for calculating extinction and the default estimate of natural background visibility. Whether EPA will approve of any changes to the IMPROVE equation is uncertain at this time. Also, the responsibility for incorporating any changes to the algorithms in CALPUFF (e.g., new f(RH) curves) is unclear. If changes to these methods are recommended by EPA, CENRAP is encouraged to adopt them. However, details of the process for incorporation of any refinements to the IMPROVE equations in the CALPUFF system should be addressed in the State's or source operators modeling protocol.

3.5 Model Availability

The EPA-approved version of the CALPUFF modeling system is available from Earth Tech, Inc., (http://www.src.com/calpuff/calpuff1.htm). The main models (CALMET, CALPUFF, and CALPOST), their GUIs, and many of the processors are available to download. One may also register to receive notices of model updates. The most recent update to the system (25 May 2005) is a new version of CALMM5 (MM5 V3) that has been added to the Download BETA-Test page. This version of CALMM5 processes MM5 Version 3 output data directly.

Earth Tech offers CALPUFF training courses that include a description of the technical formulation of the models, overviews of each of the processor programs, and hands-on application of the models to several case study data sets. Attendees of the course receive a training notebook, a workbook of case study problems, exercises, and data sets, updates on recent and future model enhancements, and the latest (proprietary) versions of the models and Graphical User Interfaces (GUIs). Other third-party training courses and materials are also available.

3.6 CALPUFF Evaluation Studies

Tesche (2002, 2003) reviewed results of various CALPUFF evaluation studies and reached the following conclusions:

- There is a paucity of model evaluation information for CALPUFF at scales of 50 to 200 km and beyond;

- Based on the limited information available, CALPUFF may be able to give unbiased estimates of short-term (i.e., 3-10 hr) concentrations of *non-reactive contaminants* to within a factor of two (e.g. 200%) out to distances of about 200 km from a source. This level or uncertainty in a 200 km radius around a source is increased if one examines CALPUFF's predictions in a particular modeling cell (e.g., one containing a population center) at a specific hour as opposed to considering the question of bias generally over the entire 200 km region irrespective of location and time of occurrence;

- For time periods of a day or less, CALPUFF is unable to produce reliable predictions of non-reactive concentrations at a specific location and time;

- What limited experimental data do exist suggest that the accuracy and reliability of the model's predictions degrade as the distance scale increases;

- While the IWAQM recommendations on the range of applicability of the CALPUFF model (50 to 200 km) rests on very sparse model evaluation information, EPA's suggestion that the model can be used for scales beyond 200 km, even with case-by-case approval, is not based on model evaluation data; and

- For chemically reactive pollutants such as SO_2, NO_x, sulfate, nitrate, nitric acid, and other secondary reaction products, the testing of CALPUFF model over extended spatial scales (50 km and beyond) has not been attempted in a rigorous manner.

Scire et al., (2001) report an evaluation of CALPUFF sulfate, nitrate, light extinction, and sulfur and nitrogen deposition at a Class I areas over a range of source-receptor distances. In this study, in which a large number of sources were modeled simultaneously, sulfate and nitrate predictions at the CASTNet monitoring site in Pinedale, Wyoming were evaluated against observations, and light extinction predictions were evaluated using transmissometer measurements. Wet sulfur and nitrogen predictions were compared to observations at several acid deposition monitoring sites. This study is especially relevant because it evaluates the performance of the model to predict variables of direct interest in Class I visibility analyses, such as sulfate and nitrate concentrations and light extinction coefficients

More recently, Chang et al., (2003) reported an intercomparison of CALPUFF with two other transport and dispersion models with high resolution field data. CALPUFF predictions for inert SF_6 were compared using two recent mesoscale field datasets: the Dipole Pride 26 (DP26) and the Overland Along-wind Dispersion (OLAD). Both field experiments involved instantaneous releases of sulfur hexafluoride tracer gas in a mesoscale region with desert basins and mountains. Tracer concentrations were observed along lines of samplers at distances up to 20 km. CALPUFF predictions were evaluated using the maximum 3-h dosage (concentration integrated over time) along a sampling line. At the DP26 sampler array, CALPUFF had mean biases within 35% and random scatters of about a factor of 3–4. About 50%–60% of the CALPUFF predictions were within a factor of 2 of the observations. At the OLAD site, the model underpredicted by a factor of 2–3, on average, with random scatters of a factor of 3–7. Only about 25%–30% of the CALPUFF predictions of inert SF_6 were within a factor of 2 of observations.

The tracer studies with which CALPUFF transport and diffusion capabilities were evaluated in the IWAQM Phase 2 report were generally over distances greater than 50 km. More recently, model performance has been performed at shorter distances including a power plant in Illinois in simple terrain at source-receptor distances in arcs ranging from 0.5 km to 50 km from the stack (Strimaitis et al., 1998). Another CALPUFF evaluation study over short-distances is reported by Morrison et al. (2003). These studies address model performance over source-receptor distances from a few hundred meters to 50 km.

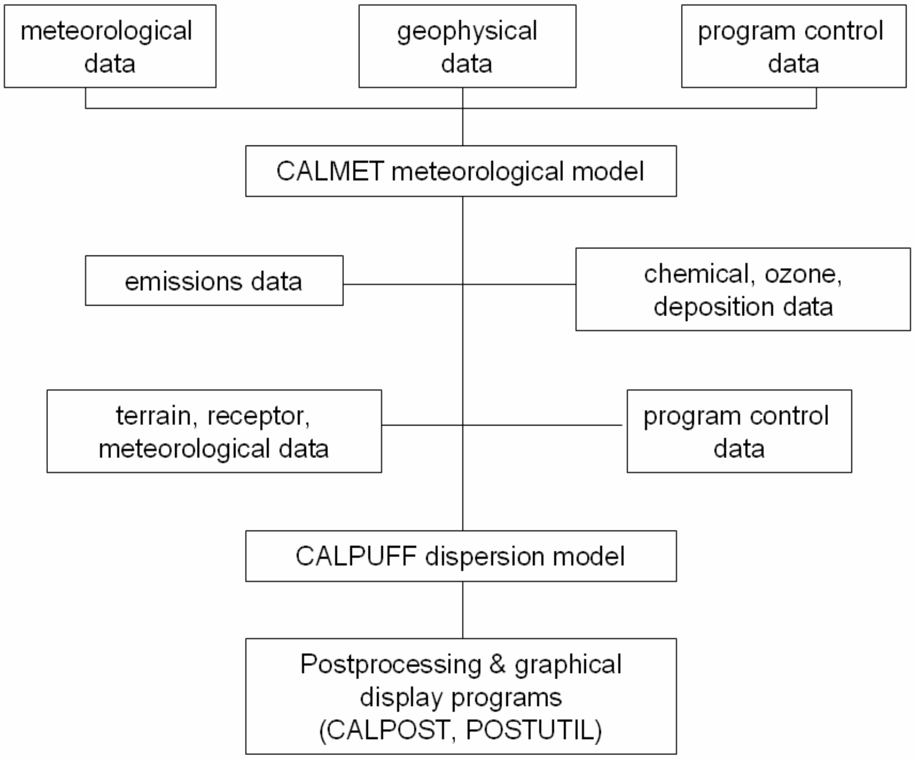

Figure 3-1. CALPUFF Modeling System Components. (Scire et al., 2000a)

Table 3-1. Major Features of the CALMET Meteorological Model. (Scire et al., 2000b)

- **Boundary Layer Modules of CALMET**
  - Overland Boundary Layer - Energy Balance Method
  - Overwater Boundary Layer - Profile Method
  - Produces Gridded Fields of:
    - Surface Friction Velocity
    - Convective Velocity Scale
    - Monin-Obukhov Length
    - Mixing Height
    - PGT Stability Class
    - Air Temperature (3-D)
    - Precipitation Rate

- **Diagnostic Wind Field Module of CALMET**
  - Slope Flows
  - Kinematic Terrain Effects
  - Terrain Blocking Effects
  - Divergence Minimization
  - Produces Gridded Fields of U, V, W Wind Components
  - Inputs Include Domain-Scale Winds, Observations, and (optionally) Coarse-Grid Prognostic Model Winds
  - Lambert Conformal Projection Capability

Table 3-2. Major Features of the CALPUFF Dispersion Model (Scire et al., 2000a)

- **Source types**
  - Point sources (constant or variable emissions)
  - Line sources (constant or variable emissions)
  - Volume sources (constant or variable emissions)
  - Area sources (constant or variable emissions)

- **Non-steady-state emissions and meteorological conditions**
  - Gridded 3-D fields of meteorological variables (winds, temperature)
  - Spatially-variable fields of mixing height, friction velocity, convective velocity scale, Monin-Obukhov length, precipitation rate
  - Vertically and horizontally-varying turbulence and dispersion rates
  - Time-dependent source and emissions data for point, area, and volume sources
  - Temporal or wind-dependent scaling factors for emission rates, for all source types

- **Interface to the Emissions Production Model (EPM)**
  - Time-varying heat flux and emissions from controlled burns and wildfires

- **Efficient sampling functions**
  - Integrated puff formulation
  - Elongated puff (slug) formulation

- **Dispersion coefficient (σ_y, σ_z) options**
  - Direct measurements of σ_v and σ_w
  - Estimated values of σ_v and σ_w based on similarity theory
  - Pasquill-Gifford (PG) dispersion coefficients (rural areas)
  - McElroy-Pooler (MP) dispersion coefficients (urban areas)
  - CTDM dispersion coefficients (neutral/stable)

- **Vertical wind shear**
  - Puff splitting
  - Differential advection and dispersion

- **Plume rise**
  - Buoyant and momentum rise
  - Stack tip effects
  - Building downwash effects
  - Partial penetration
  - Vertical wind shear

- **Building downwash**

  - Huber-Snyder method
  - Schulman-Scire method
  - PRIME method

Table 3-2. Major Features of the CALPUFF Dispersion Model (Concluded).

- **Complex terrain**
  - Steering effects in CALMET wind field
  - Optional puff height adjustment: ISC3 or "plume path coefficient"
  - Optional enhanced vertical dispersion (neutral/weakly stable flow in CTDMPLUS)

- **Subgrid scale complex terrain (CTSG option)**
  - Dividing streamline, H_d, as in CTDMPLUS:
    - Above H_d, material flows over the hill and experiences altered diffusion rates
    - Below H_d, material deflects around the hill, splits, and wraps around the hill

- **Dry Deposition**
  - Gases and particulate matter
  - Three options:
    - Full treatment of space and time variations of deposition with a resistance model
    - User-specified diurnal cycles for each pollutant
    - No dry deposition

- **Overwater and coastal interaction effects**
  - Overwater boundary layer parameters
  - Abrupt change in meteorological conditions, plume dispersion at coastal boundary
  - Plume fumigation

- **Chemical transformation options**
  - Pseudo-first-order chemical mechanism for SO_2, $SO_4^=$, NO_x, HNO_3, and NO_3^- (MESOPUFF II method)
  - Pseudo-first-order chemical mechanism for SO_2, $SO_4^=$, NO, NO_2 HNO_3, and NO_3^- (RIVAD/ARM3 method)
  - User-specified diurnal cycles of transformation rates
  - No chemical conversion

- **Wet Removal**
  - Scavenging coefficient approach
  - Removal rate a function of precipitation intensity and precipitation type

Table 3-3. Parameter Variations in Box Model Simulations Used to Develop the CALPUFF Sulfate and Nitrate Formation Algorithms. (Morris et al., 2003).

<table>
<tr><th>Surrogate Parameter</th><th>Number of Variations</th><th>Model Input Parameters And Variations</th></tr>
<tr><td>Season</td><td>3</td><td>Temperatures of 30, 20 and 10 °C were used for the, respectively, summer, fall and winter seasons. Diurnally varying clear skies solar radiation was assumed for each season corresponding to a latitude of 40°.</td></tr>
<tr><td>Background Air Reactivity</td><td>4</td><td>For the summer season the following four levels of background ozone and VOCs were used:
<table>
<tr><th>Ozone (ppb)</th><th>VOC (ppbC)</th></tr>
<tr><td>20</td><td>50</td></tr>
<tr><td>50</td><td>250</td></tr>
<tr><td>80</td><td>500</td></tr>
<tr><td>200</td><td>2,000</td></tr>
</table>
For fall and winter the ozone concentrations were assumed to be 75% and 50% of the summer levels.</td></tr>
<tr><td>Dispersion</td><td>2</td><td>Two different rates of plume dispersion were used: (1) a stable case with a wind speed of 1.5 m/s and; (2) a slightly unstable case with a wind speed of 5.0 m/s.</td></tr>
<tr><td>Release Time</td><td>2</td><td>Photochemical box model simulations were performed with release times of sunrise and noon.</td></tr>
<tr><td>Plume NOx Concentration</td><td>3</td><td>Initial plume NOx concentrations of 7, 350 and 1400 ppb were used.</td></tr>
</table>

APPENDIX B – CONTROLS COST ANALYSES

Estimated Average Cost ($/ton) of Methane DeNOx on No. 1 Power Boiler - NOx Control

CAPITAL COSTS		**Costs ($)**
Direct Costs		
Purchased Equipment Cost[a]	**$**	**1,050,000**
Budgetary Qualifier (+/-25%)		262,500
		1,312,500
Direct installation costs		
Foundation and supports		
Handling and erection		
Electrical		
Piping		
Insulation		
Painting		
Direct installation Costs		656,250
Total Direct Capital Cost = Equip Cost + 1.5*Equip Cost[b]	$	1,968,750
Indirect Capital Costs	=1.0 x Total Direct Cost	
Engineering		
Construction and field expenses		
Contrator fees		
Start-up		
Performance test		
Contingencies		
Structural Modification (4%)		
Total Indirect Capital Costs[b]	$	1,968,750
TOTAL CAPITAL INVESTMENT (TCI = DC+IC)	**$**	**3,937,500**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor[c]		9,022
Operating Labor Supervision[d]		1,353
Maintenance Labor[e]		9,922
Maintenance Materials[f]		9,922
Utilities - Electricity[g]		112,560
Utilities - Natural Gas[l]		3,108,000
Waste Treatment & Disposal		
Total Direct Operating Costs	$	3,250,779
Indirect Operating Costs		
Overhead[h]		18,131
Property Tax[i]		39,375
Insurance[i]		39,375
Administration[j]		78,750
Capital Recovery (5% interest, 10 year life)[k]		509,924
Total Indirect Operating	$	685,555
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)	**$**	**3,936,334**
Total Annualized Costs		3,936,334
Total Uncontrolled NOx Emissions (tpy)		1084
Removal Effciency		0.5
Pollutant Removed(tpy)		542
Cost/Ton Pollutant Removed	**$**	**7,262**

[a] Based on the equipment cost estimate from Energy Systems Associates

[b] Factored estimate based on recent capital project installations

[c] Operating labor = 0.75 hours/day @ $34.37/hr rate for 350 days/year

[d] Supervisor pay = 15% of Operator pay

[e] Maintenance = 240 hours @ $41.34/hr

[f] Maintenance Materials = 100% of Maintenance Labor

[g] Electrical usage (335kW) associated with running fans; from Energy Systems Associates estimate for OFA/FGR combo

[h] Overhead = 60% of Labor & Material

[i] =1% TCI (Total Capital Investment)

[j] =2% TCI (Total Capital Investment)

k =factor of 0.129504575 for 5% interest on 10 year life

[l] = Natural gas usage at $370/hr at $8/MMBTL

Estimated Average Cost ($/ton) of OFA System Upgrade on No. 1 Power Boiler - NOx Control

CAPITAL COSTS		**Costs ($)**
Direct Costs		
Purchased Equipment Cost[a]	**$**	**2,980,000**
Budgetary Qualifier (+/-25%)		745,000
		3,725,000
Direct installation costs		
Foundation and supports		
Handling and erection		
Electrical		
Piping		
Insulation		
Painting		
Direct installation Costs		1,862,500
Total Direct Capital Cost = Equip Cost + 1.5*Equip Cost[b]	$	5,587,500
Indirect Capital Costs	=1.0 x Total Direct Cost	
Engineering		
Construction and field expenses		
Contrator fees		
Start-up		
Performance test		
Contingencies		
Structural Modification (4%)		
Total Indirect Capital Costs[b]	$	5,587,500
TOTAL CAPITAL INVESTMENT (TCI = DC+IC)	**$**	**11,175,000**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor[c]		9,022
Operating Labor Supervision[d]		1,353
Maintenance Labor[e]		9,922
Maintenance Materials[f]		9,922
Utilities - Electricity[g]		112,560
Utilities - Water		
Waste Treatment & Disposal		
Total Direct Operating Costs	$	142,779
Indirect Operating Costs		
Overhead[h]		18,131
Property Tax[i]		111,750
Insurance[i]		111,750
Administration[j]		223,500
Capital Recovery (5% interest, 10 year life)[k]		1,447,214
Total Indirect Operating	$	1,912,345
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)	**$**	**2,055,123**
Total Annualized Costs		2,055,123
Total Uncontrolled NOx Emissions (tpy)		1084
Removal Effciency		0.4
Pollutant Removed(tpy)		434
Cost/Ton Pollutant Removed	**$**	**4,740**

[a] Based on the equipment cost estimate provided by Jansen Combustion and Boiler Technologies Inc.

[b] Factored estimate based on recent capital project installations

[c] Operating labor = 0.75 hours/day @ $34.37/hr rate for 350 days/yea

[d] Supervisor pay = 15% of Operator pay

[e] Maintenance = 240 hours @ $41.34/hı

[f] Maintenance Materials = 100% of Maintenance Labo

[g] Electrical usage (335kW) associated with running fans; from Energy Systems Associates estimate for OFA/FGR combo

[h] Overhead = 60% of Labor & Material

[i] =1% TCI (Total Capital Investment)

[j] =2% TCI (Total Capital Investment)

k =factor of 0.129504575 for 5% interest on 10 year life

Estimated Average Cost ($/ton) of Methane DeNOx on No. 2 Power Boiler - NOx Control

CAPITAL COSTS		**Costs ($)**
Direct Costs		
Purchased Equipment Cost[a]	**$**	**1,200,000**
Budgetary Qualifier (+/-25%)		300,000
		1,500,000
Direct installation costs		
Foundation and supports		
Handling and erection		
Electrical		
Piping		
Insulation		
Painting		
Direct installation Costs		750,000
Total Direct Capital Cost = Equip Cost + 1.5*Equip Cost[b]	$	2,250,000
Indirect Capital Costs	=1.0 x Total Direct Cost	
Engineering		
Construction and field expenses		
Contrator fees		
Start-up		
Performance test		
Contingencies		
Structural Modification (4%)		
Total Indirect Capital Costs[b]	$	2,250,000
TOTAL CAPITAL INVESTMENT (TCI = DC+IC)	**$**	**4,500,000**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor[c]		9,022
Operating Labor Supervision[d]		1,353
Maintenance Labor[e]		9,922
Maintenance Materials[f]		9,922
Utilities - Electricity[g]		141,120
Utilities - Natural Gas[l]		4,401,600
Waste Treatment & Disposal		
Total Direct Operating Costs	$	4,572,939
Indirect Operating Costs		
Overhead[h]		18,131
Property Tax[i]		45,000
Insurance[i]		45,000
Administration[j]		90,000
Capital Recovery (5% interest, 10 year life)[k]		582,771
Total Indirect Operating	$	780,902
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)	**$**	**5,353,840**
Total Annualized Costs		5,353,840
Total Uncontrolled NOx Emissions (tpy)		2514
Removal Effciency		0.5
Pollutant Removed(tpy)		1257
Cost/Ton Pollutant Removed	**$**	**4,259**

[a] Based on the equipment cost estimate from Energy Systems Associates

[b] Factored estimate based on recent capital project installations

[c] Operating labor = 0.75 hours/day @ $34.37/hr rate for 350 days/year

[d] Supervisor pay = 15% of Operator pay

[e] Maintenance = 240 hours @ $41.34/hr

[f] Maintenance Materials = 100% of Maintenance Labor

[g] Electrical usage (420kW) associated with running fans; from Energy Systems Associates estimate for OFA/FGR combo

[h] Overhead = 60% of Labor & Material

[i] =1% TCI (Total Capital Investment)

[j] =2% TCI (Total Capital Investment)

k =factor of 0.129504575 for 5% interest on 10 year life

[l] = Natural gas usage at $524/hr at $8/MMBTU

Estimated Average Cost ($/ton) of OFA System Upgrade on No. 2 Power Boiler - NOx Control

CAPITAL COSTS		**Costs ($)**
Direct Costs		
Purchased Equipment Cost[a]	**$**	**4,338,880**
Budgetary Qualifier (+/-25%)		1,084,720
		5,423,600
Direct installation costs		
Foundation and supports		
Handling and erection		
Electrical		
Piping		
Insulation		
Painting		
Direct installation Costs		2,711,800
Total Direct Capital Cost = Equip Cost + 1.5*Equip Cost[b]	$	8,135,400
Indirect Capital Costs	=1.0 x Total Direct Cost	
Engineering		
Construction and field expenses		
Contrator fees		
Start-up		
Performance test		
Contingencies		
Structural Modification (4%)		
Total Indirect Capital Costs[b]	$	8,135,400
TOTAL CAPITAL INVESTMENT (TCI = DC+IC)	**$**	**16,270,800**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor[c]		9,022
Operating Labor Supervision[d]		1,353
Maintenance Labor[e]		9,922
Maintenance Materials[f]		9,922
Utilities - Electricity[g]		141,120
Utilities - Water		
Waste Treatment & Disposal		
Total Direct Operating Costs	$	171,339
Indirect Operating Costs		
Overhead[h]		18,131
Property Tax[i]		162,708
Insurance[i]		162,708
Administration[j]		325,416
Capital Recovery (5% interest, 10 year life)[k]		2,107,143
Total Indirect Operating	$	2,776,106
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)	**$**	**2,947,445**
Total Annualized Costs		2,947,445
Total Uncontrolled NOx Emissions (tpy)		2514
Removal Effciency		0.4
Pollutant Removed(tpy)		1006
Cost/Ton Pollutant Removed	**$**	**2,931**

[a] Scaled from quote for #1 PB based on six-tenths factor rule for cost estimation from Peters, Max S. and Timmerhaus, Klaus D., Plant Design and Economics for Chemical Engineers, Fourth Edition, McGraw-Hill, Inc., 1991, p. 169.

[b] Factored estimate based on recent capital project installations

[c] Operating labor = 0.75 hours/day @ $34.37/hr rate for 350 days/year

[d] Supervisor pay = 15% of Operator pay

[e] Maintenance = 240 hours @ $41.34/hr

[f] Maintenance Materials = 100% of Maintenance Labor

[g] Electrical usage assumption (420kW) associated with running auxiliary equipment; from Energy Systems Associates estimate for OFA/FGR combo

[h] Overhead = 60% of Labor & Material

[i] =1% TCI (Total Capital Investment)

[j] =2% TCI (Total Capital Investment)

k =factor of 0.129504575 for 5% interest on 10 year life

Estimated Average Cost ($/ton) of Low NOx Burners on No. 2 Power Boiler - NOx Control

CAPITAL COSTS		**Costs ($)**
Direct Costs		
Purchased Equipment Cost[a]	**$**	**1,800,000**
Direct installation costs		
Foundation and supports		
Handling and erection		
Electrical		
Piping		
Insulation		
Painting		
Direct installation Costs		900,000
Total Direct Capital Cost = Equip Cost + 1.5*Equip Cost[b]	$	2,700,000
Indirect Capital Costs	=1.0 x Total Direct Cost	
Engineering		
Construction and field expenses		
Contrator fees		
Start-up		
Performance test		
Contingencies		
Structural Modification (4%)		
Total Indirect Capital Costs[b]	$	2,700,000
TOTAL CAPITAL INVESTMENT (TCI = DC+IC)	**$**	**5,400,000**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor[c]		9,022
Operating Labor Supervision[d]		1,353
Maintenance Labor[e]		9,922
Maintenance Materials[f]		9,922
Utilities - Electricity[g]		141,120
Utilities - Water		
Waste Treatment & Disposal		
Total Direct Operating Costs	$	171,339
Indirect Operating Costs		
Overhead[h]		18,131
Property Tax[i]		54,000
Insurance[i]		54,000
Administration[j]		108,000
Capital Recovery (5% interest, 10 year life)[k]		699,325
Total Indirect Operating	$	933,456
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)	**$**	**1,104,795**
Total Annualized Costs		1,104,795
Total Uncontrolled NOx Emissions (tpy)		2514
Removal Effciency		0.3
Pollutant Removed(tpy)		754
Cost/Ton Pollutant Removed	**$**	**1,465**

BEST AVAILABLE RETROFIT TECHNOLOGY DETERMINATION

DOMTAR INDUSTRIES INC. ▪ ASHDOWN MILL (AFIN 41-00002)

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Project 060401.0081

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION

Domtar Industries Inc. (Domtar) owns and operates a kraft paper mill located at 285 Highway 71 South in Ashdown, Arkansas (the Ashdown Mill). The Ashdown Mill is a major source as defined in Arkansas Pollution Control and Ecology Commission (ADP&E) Regulation 26, *Regulations of the Arkansas Operating Air Permit Program*, and currently operates under the authority of Arkansas Department of Environmental Quality (ADEQ) Operating Air Permit 0287-AOP-R6, which was issued on July 12, 2006.

The ADEQ has determined that the Ashdown Mill operates two emission units – No. 1 and No. 2 Power Boilers – that are eligible to be regulated under the Best Available Retrofit Technology (BART) provisions of the U.S. Environmental Protection Agency's (EPA) Regional Haze Rule in Title 40 of the Code of Federal Regulations (40 CFR) Part 51. BART is the primary mechanism identified for regulating haze-forming pollutants from stationary sources for the first implementation period under the Regional Haze Rule. The ADEQ has also determined, based on air dispersion modeling, that emissions from the Ashdown Mill BART-eligible source contributes to visibility impairment at a federally protected Class I area. Therefore, Domtar has prepared this report to document its BART determination in accordance with *Appendix Y to Part 51 – Guidelines for BART Determinations Under the Regional Haze Rule* (the BART Guidelines).

An overview of the Regional Haze Rule and BART Guidelines is provided in Section 1.1. Descriptions of the Ashdown Mill's BART-eligible emission units are included in Section 2. Section 3 describes the BART applicability analysis completed by the ADEQ for the Ashdown Mill BART-eligible source. Domtar's BART determination analysis is included in Section 4.

1.1 OVERVIEW OF REGIONAL HAZE RULE AND BART GUIDELINES

The Regional Haze Rule requires that major sources of visibility-affecting pollutants belonging to one or more of 26 specific industrial source categories evaluate BART if the source was in existence before August 7, 1977 and began operation after August 7, 1962. "Major sources of visibility-affecting pollutants" are sources that have the potential to emit 250 tons per year (tpy) or more of any of the following: oxides of nitrogen (NO_X), sulfur dioxide (SO_2), or particulate matter (PM).[1] The "BART-eligible source" is the collection of sources at a facility meeting the applicability criteria.

1.1.1 BART APPLICABILITY

In the BART applicability analysis, a BART-eligible source is determined to be subject to BART if it causes or contributes to visibility impairment at one or more of the 156 federally protected Class I areas. Per the U.S. EPA's BART Modeling Guidance, "an individual source will be considered to 'cause visibility impairment' if the emissions

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[1] As allowed in the BART Guidelines, the ADEQ has determined that volatile organic compounds (VOC) and ammonia are not visibility-affecting pollutants for the purposes of BART analyses.

results in a change (delta △) in deciviews (dv)[2] that is greater than or equal to 1.0 deciview on the visibility in a Class I area…if the emissions from a source results in a change in visibility that is greater than or equal to 0.5 dv in a Class I area the source will be considered to 'contribute to visibility impairment.'" To determine whether a BART-eligible facility causes or contributes to visibility impairment, the U.S. EPA guidance requires the use of an air quality model, specifically recommending the CALPUFF modeling system, to quantify the impacts attributable to a single BART-eligible source. Because contribution to visibility impairment is sufficient cause to require a BART determination, 0.5 dv is the critical threshold for assessment of BART applicability.

Regional haze is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index (*HI*) expressed in dv. The *HI* is calculated as shown in the following equation.

$$HI = 10\ln\left(\frac{b_{ext}}{10}\right)$$

The impact of a BART-eligible source is determined by comparing the *HI* attributable to a source to estimated natural background conditions. That is, a single-source visibility impact is measured as the change in light extinction versus background, and is referred to as △dv. The background extinction coefficient is affected by various chemical species and the Rayleigh scattering phenomenon and can be calculated as shown in the following equation.

$$b_{ext,background}\left(\text{Mm}^{-1}\right) = b_{SO_4} + b_{NO_3} + b_{OC} + b_{Soil} + b_{Coarse} + b_{EC} + b_{Ray}$$

where:

$b_{SO_4} = 3\left[(\text{NH}_4)_2\text{SO}_4\right]f(RH)$
$b_{NO_3} = 3\left[\text{NH}_4\text{NO}_3\right]f(RH)$
$b_{OC} = 4[\text{OC}]$
$b_{Soil} = 1[\text{Soil}]$
$b_{Coarse} = 0.6[\text{Coarse Mass}]$
$b_{EC} = 10[\text{EC}]$
$b_{Ray} = \text{Rayleigh Scattering}\left(10\ \text{Mm}^{-1}\ \text{by default}\right)$
$f(RH) = \text{Relative Humidity Function}$
$[\ ] = \text{Concentration in}\ \mu\text{g}/\text{m}^3$

$\left[(\text{NH}_4)_2\text{SO}_4\right]$ denotes the ammonium sulfate concentration
$\left[\text{NH}_4\text{NO}_3\right]$ denotes the ammonium nitrate concentration
$[\text{OC}]$ denotes the concentration of organic carbon
$[\text{Soil}]$ denotes the concentration of fine soils
$[\text{Coarse Mass}]$ denotes the concentration of coarse dusts
$[\text{EC}]$ denotes the concentration of elemental carbon
Rayleigh Scattering is scattering due to air molecules

Values for the parameters listed above specific to the natural background conditions at each Class I area are provided on an annual-average basis in the U.S. EPA's *Guidance for Estimating Natural Visibility Conditions under the Regional Haze Rule*.[3]

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[2] The deciview (dv) is a metric used to represent normalized light extinction attributable to visibility-affecting pollutants.

[3] U.S. EPA, *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, Table 2-1, Attachment A, September 2003, EPA-454/B-03-005.

Particulate species that affect visibility are emitted from anthropogenic (human-caused) sources and include coarse particulate matter (PMC), fine particulate matter (PMF), and elemental carbon (EC) as well as precursors to secondary organic aerosols (SOA) and fine particulate matter such as SO_2 and NO_X. The extinction coefficient due to emissions of visibility-affecting pollutants from a single BART-eligible source is calculated according to the following equation.

$$b_{ext,source}\left(\mathrm{Mm}^{-1}\right) = b_{SO_4} + b_{NO_3} + b_{SOA} + b_{PMF} + b_{PMC} + b_{EC}$$

where:

$$b_{SO_4} = 3\left[(\mathrm{NH_4})_2\mathrm{SO_4}\right] f(RH)$$
$$b_{NO_3} = 3\left[\mathrm{NH_4NO_3}\right] f(RH)$$
$$b_{SOA} = 4[\mathrm{SOA}]$$
$$b_{PMF} = 1[\mathrm{PMF}]$$
$$b_{PMC} = 0.6[\mathrm{PMC}]$$
$$b_{EC} = 10[\mathrm{EC}]$$
$$f(RH) = \text{Relative Humidity Function}$$
$$[\;] = \text{Concentration in } \mu\mathrm{g/m^3}$$

$\left[(\mathrm{NH_4})_2\mathrm{SO_4}\right]$ denotes the ammonium sulfate concentration
$\left[\mathrm{NH_4NO_3}\right]$ denotes the ammonium nitrate concentration
$[\mathrm{SOA}]$ denotes the concentration of secondary organic aerosols
$[\mathrm{PMF}]$ denotes the concentration of fine PM
$[\mathrm{PMC}]$ denotes the concentration of coarse PM
$[\mathrm{EC}]$ denotes the concentration of elemental carbon

1.1.1.1 CALPUFF MODELING ANALYSES

As stated above, the BART Guidelines recommend using the CALPUFF modeling system to compute the 24-hour average visibility impairment attributable to a BART-eligible source to assess whether the 0.5 Δdv contribution threshold is exceeded, and if so, the frequency, duration, and magnitude of any exceedance events. CALPUFF is a refined air quality modeling system that is capable of simulating the dispersion, chemical transformation, and long-range transport of multiple visibility-affecting pollutant emissions and is therefore preferred for BART applicability and determination analyses.

1.1.2 BART DETERMINATION

BART-eligible sources that are found to cause or contribute to visibility impairment at a Class I area are required to make a BART determination. The BART Guidelines define BART as follows:

> *BART means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life*

of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. The BART analysis identifies the best system of continuous emission reduction taking into account:

(1) The available retrofit control options,
(2) Any pollution control equipment in use at the source (which affects the availability of options and their impacts),
(3) The costs of compliance with control options,
(4) The remaining useful life of the facility,
(5) The energy and non-air quality environmental impacts of control options[*, and*]
(6) The visibility impacts analysis.

2. BART-ELIGIBLE EMISSION UNITS

The BART Guidelines define the following three steps for determining which emission units at a facility are BART-eligible:

1. Identify the emission units in the BART source categories,
2. Identify the start-up dates of those units, and
3. Compare potential emissions to the 250 ton/yr cutoff.

"Fossil-fuel boilers of more than 250 million BTUs per hour heat input" are one of the listed BART source categories. The Ashdown Mill's No. 1 and No. 2 Power Boilers are each greater than 250 million British thermal units per hour (MMBtu/hr), were in existence on August 7, 1977, began operation after August 7, 1962, and each have potential emissions greater than 250 tpy of PM, NO_X, or SO_2; therefore, these units make up the Ashdown Mill's BART-eligible source. A summary of the BART eligibility criteria for each emission unit is provided in Table 2-1.

TABLE 2-1. SUMMARY OF BART-ELIGIBLE EMISSION UNITS

Emission Unit	Source Number	BART Source Category	Year of Completion of Construction or Reconstruction	Potential SO_2 Emissions (tpy)	Potential NO_X Emissions (tpy)	Potential PM/PM_{10} Emissions (tpy)
No. 1 Power Boiler	SN-03	Boiler [a]	1968	214.0	1,084.1	1,502.3
No. 2 Power Boiler	SN-05	Boiler [a]	1976	4,305.5	2,514.1	359.2

[a] Fossil-fuel boilers of more than 250 million BTUs per hour heat input.

Detailed descriptions of each unit are provided in the sub-sections below.

2.1 NO. 1 POWER BOILER

The No. 1 Power Boiler (SN-03), also known as the Bark Boiler, was installed in 1968. It has a heat input rating of 580 MMBtu/hr and an average steam generation rate of approximately 120,000 pounds per hour (lb/hr). It combusts primarily bark (approximately 75 percent of the heat input is supplied by bark), but is also permitted to burn bark and wood chips used to absorb oil spills, wood waste, recycled sanitary products composed of cellulose and polypropylene, pelletized paper fuel (PPF), tire-derived fuel (TDF), municipal yard waste, No. 6 fuel oil, reprocessed fuel oil, used oil generated on site, and natural gas. Natural gas is only used to supplement other fuels during high steam demand periods. Fuel oil usage is limited to 2,700,000 gallons per year, and the sulfur content of the fuel oil used is limited to 3.0 percent by weight. TDF usage (total for No.1, No. 2, and No. 3 Power Boilers) is limited to 220 tons per day.

The No. 1 Power Boiler is equipped with a traveling grate, a combustion air system, and multiclones.

The No. 1 Power Boiler is not subject to any New Source Performance Standards (NSPS) in 40 CFR Part 60. It is subject to 40 CFR Part 63, Subpart DDDDD, *National Emissions Standard for Hazardous Air Pollutants* (NESHAP) *for Industrial, Commercial, and Institutional Boilers and Process Heaters*. NESHAP DDDDD establishes Maximum Achievable Control Technology (MACT) limits and is commonly referred to as "the Boiler MACT."

To meet the applicable Boiler MACT PM emission standard of 0.07 lb/Mmbtu, Domtar is preparing to install a wet electrostatic precipitator (WESP) on the No. 1 Power Boiler.

2.2 NO. 2 POWER BOILER

The No. 2 Power Boiler (SN-05) started operations in February 1976. It has a heat input rating of 820 MMBtu/hr and an average steam generation rate of approximately 600,000 lb/hr. It combusts primarily bituminous coal (over 80 percent of the heat input is supplied by coal), but is also permitted to burn bark, bark and wood chips used to absorb oil spills, wood waste, petroleum coke (pet coke), recycled sanitary products based on cellulose and polypropylene, PPF, TDF, municipal yard waste, No. 6 fuel oil, reprocessed fuel oil, used oil generated on site, natural gas, and non-condensable gases (NCGs). The NCGs are produced in the pulp area (from the cooking of chips) and evaporator area (where weak black liquor is concentrated) and consist of nitrogen, total reduced sulfur (TRS) compounds, methanol, acetone, SO_2, and minor quantities of other compounds such as methyl ethyl ketone (MEK). Under normal operating conditions, natural gas is not combusted.

The No. 2 Power Boiler is equipped with a traveling grate, combustion air system including overfire air, multiclones, and two parallel venturi scrubbers. The SO_2 loading to the boiler is significant since the boiler burns coal and NCGs. Therefore, the scrubbing fluid includes water and a source of alkali, such as sodium hydroxide (i.e., caustic) and/or pulp mill extraction stage filtrate.

The No. 2 Power Boiler is subject to 40 CFR 60, Subpart D, *Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971*, 40 CFR 60, Subpart BB, *Standards of Performance for Kraft Pulp and Paper Mills* (since it combusts NCGs), and 40 CFR Part 63, Subpart DDDDD, *National Emissions Standard for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters*.

The No. 2 Power Boiler is equipped with Continuous Emissions Monitoring Systems (CEMS) for NO_X, SO_2, and carbon monoxide (CO). In accordance with 40 CFR 60, Subpart BB, the No. 2 Power Boiler also has a continuous flame pyrometer to measure the temperature at the point of NCG injection (the temperature at the injection point must remain at or above 1200 ºF for at least 0.5 seconds at all times that NCGs are being burned).

3. BART APPLICABILITY ANALYSIS

This section summarizes the source-specific inputs and results of the BART applicability analysis conducted by the ADEQ for Domtar's Ashdown Mill BART-eligible source. The screening modeling methodologies and data resources used by the ADEQ in executing the CALPUFF modeling system are described in technical detail in the ADEQ's *Draft BART Modeling Protocol* (the Protocol), dated June 7, 2006, and in the Central Regional Air Planning Association (CENRAP) *BART Modeling Guidelines* (issued on December 22, 2005, and re-issued on February 3, 2006). A copy of the Protocol is included in Appendix A.

3.1 MODELED ASHDOWN MILL EMISSIONS

Whereas the BART eligibility determination relies on current potential emissions of visibility-affecting pollutants, the BART applicability modeling analysis is based on maximum 24-hour average actual emission rates of NO_X, SO_2, and PM_{10} for the modeled three-year period (i.e., 2001, 2002, & 2003).[4] At the ADEQ's request, Domtar estimated the 24-hour average maximum actual emission rates of visibility-affecting pollutants from the No. 1 and No. 2 Power Boilers using a combination of CEMS data, source-specific stack testing results, and emission factors from U.S. EPA's AP-42. These emission rates are summarized in Table 3-1.

TABLE 3-1. SUMMARY OF 24-HOUR AVERAGE MAXIMUM ACTUAL EMISSION RATES

Emission Unit	**NO_X Emissions (lb/hr)**	**SO_2 Emissions (lb/hr)**	**PM_{10}/PMF Emissions (lb/hr)**
No. 1 Power Boiler	179.6	442.5	169.5
No. 2 Power Boiler	526.8	788.2	81.6

3.2 MODELED ASHDOWN MILL STACK PARAMETERS

Actual stack parameters were input to the CALPUFF model to represent each emissions point. The location of each point was represented using the Lambert Conformal Coordinate (LCC) system. According to the Protocol, because the BART modeling focuses on mesoscale transport to Class I areas, effects of building downwash were not considered in the ADEQ's analysis. Table 3-2 summarizes the stack parameters modeled for the BART-eligible emission units at Domtar's Ashdown Mill.

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[4] The ADEQ assumed all PM_{10} emissions were PMF for modeling purposes.

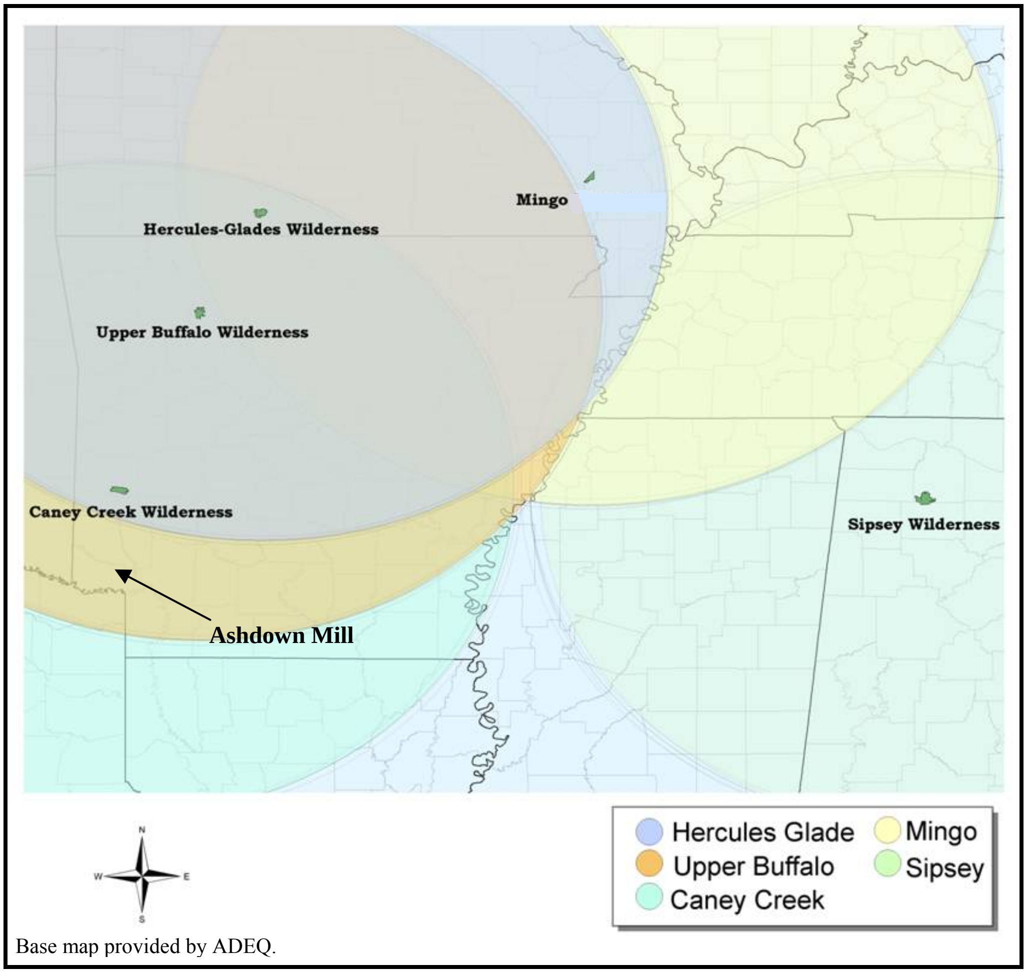
TABLE 3-2. STACK PARAMETERS

Emission Unit	LCC East (km)	LCC North (km)	Base Elevation (m)	Stack Height (m)	Stack Diameter (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)
No. 1 Power Boiler	267.47491	-698.66686	97.5	66.1	1.890	522	26.76
No. 2 Power Boiler	267.48245	-698.74355	97.5	71.6	3.659	325	11.92

3.3 POTENTIALLY AFFECTED CLASS I AREAS

Regardless of distance from the BART-eligible source, the ADEQ evaluated all Class I areas within 300 km of the Arkansas state boundary in all analyses. Figure 3-1 illustrates the location of the Ashdown Mill relative to each of the modeled Class I areas.

FIGURE 3-1. LOCATION OF ASHDOWN MILL RELATIVE TO MODELED CLASS I AREAS



Base map provided by ADEQ.

Table 3-3 presents the Class I areas (and responsible Federal Land Manager [FLM]) included in ADEQ's analyses and the approximate distance from each area to the Ashdown Mill.

TABLE 3-3. MODELED CLASS I AREAS

Class I Area	FLM [a]	Approximate Distance from Ashdown Mill (km)
Caney Creek Wilderness	FS	85
Upper Buffalo Wilderness	FS	250
Hercules-Glades Wilderness	FS	350
Mingo Refuge	FWS	510
Sipsey Wilderness	FS	620

[a] FS = Forest Service (Department of Agriculture), FWS = Fish and Wildlife Service (Department of Interior).

3.4 BART APPLICABILITY ANALYSIS RESULTS

The ADEQ's BART applicability analysis showed that Domtar's Ashdown Mill contributes to visibility impairment, since the maximum modeled 24-hour average impacts were greater than 0.5 Δdv, in the Caney Creek, Upper Buffalo, Hercules-Glades, and Mingo Class I areas. The results of the ADEQ's BART applicability analysis for Domtar's Ashdown Mill are summarized in Table 3-4.

TABLE 3-4. SUMMARY OF BART APPLICABILITY ANALYSIS RESULTS

Class I Area	Maximum 24-hour Impact (Δdv) [a]	Number of Days > 0.5 Δdv [a]	Number of Days > 1.0 Δdv [a]
Caney Creek	2.262	159	50
Upper Buffalo	1.181	18	1
Hercules-Glades	0.701	3	0
Mingo	0.923	2	0
Sipsey	0.341	0	0

[a] For total modeled period: years 2001, 2002, and 2003.

Since the ADEQ's BART applicability analysis shows that Domtar's Ashdown Mill BART-eligible source contributes to visibility impairment in at least one Class I area, Domtar must conduct a BART determination analysis for the No. 1 and No. 2 Power Boilers.

4. BART DETERMINATION ANALYSIS

In general, BART is determined for each eligible emissions unit using the following five (5) steps from Section IV.D of the BART Guidelines:

Step 1 – Identify all available retrofit control technologies,
Step 2 – Eliminate technically infeasible options,
Step 3 – Evaluate control effectiveness of remaining control technologies,
Step 4 – Evaluate impacts and document the results, and
Step 5 – Evaluate visibility impacts.

However, in the preamble to the BART Guidelines, the U.S. EPA clearly encourages the use of streamlined approaches for BART determinations so that states and industry can focus their resources on the main contributors to visibility impairment.[5] Domtar asserts that streamlined BART determinations are appropriate for emissions of PM and SO_2 from the Ashdown Mill's No. 1 and No. 2 Power Boilers. The streamlined BART determinations for PM and SO_2 are presented in Sections 4.1, 4.2, and 4.3. Steps 1 through 4 of the BART determination analysis for NO_X emissions from the No. 1 and No. 2 Power Boilers are presented in Section 4.3. Section 4.5 presents the visibility impacts evaluation for all pollutants.

4.1 BART DETERMINATION FOR PM

Section IV.C of the BART Guidelines describes a streamlined approach for evaluating BART for certain sources that are subject to MACT standards (i.e., NESHAP in 40 CFR 63). The Ashdown Mill's No. 1 and No. 2 Power Boilers are affected sources (in the existing, large, solid fuel subcategory) under the Boiler MACT, and are subject to a PM emissions standard of 0.07 lb/MMBtu. Since the Boiler MACT standard was established recently the technology analysis is up-to-date. The No. 1 and No. 2 Power Boilers must be in compliance with the Boiler MACT standards by September 13, 2007, in advance of the anticipated 2013 BART compliance deadline. Domtar is planning to equip the No. 1 Power Boiler with a WESP to meet the PM standard. The No. 2 Power Boiler is equipped with a wet scrubber and can meet the Boiler MACT PM emission standard. Domtar has not identified any feasible upgrades to the No. 2 Power Boiler's wet scrubber. At ADEQ's request, Domtar evaluated the costs for installing a WESP on the No. 2 Power Boiler. The estimated cost effectiveness, based on the estimates given in the proposal for the WESP on the No. 1 Power Boiler, is at a minimum $30,000/ton – clearly infeasible. Table 4-1 presents the maximum PM emission rates from each power boiler based on heat input capacity and the Boiler MACT standard.

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[5] Federal Register, Vol. 70, No. 128, July 6, 2005, pp 39107 and 39116.

TABLE 4-1. BART / BOILER MACT-BASED PM EMISSION RATES

Emission Unit	PM Emissions (lb/hr)	PM Emissions (tpy)
No. 1 (Bark) Power Boiler	40.6	177.9
No. 2 (Coal) Power Boiler	57.4	251.5

The recent Boiler MACT PM emission standard is presumptively relied upon to meet BART requirements. Accordingly, a comprehensive BART determination analysis is not necessary to determine BART for PM emissions from the Ashdown Mill's No. 1 and No. 2 Power Boilers. The ADEQ agreed to allow this streamlined MACT-equals-BART option in a September 8, 2006, letter, but required that Domtar "consult with the ADEQ Air Division regarding whether the wet electrostatic precipitator (MACT Control) is the best available and cost effective control technology for $PM_{2.5}$."[6] Domtar provides the following evidence that a WESP is the best choice for control of the No. 1 Power Bark Boiler.

Particulate emissions from wood-fired boilers are typically controlled by one of four technologies: baghouse (fabric filter), ESP (wet or dry), wet scrubber, or cyclone. Cyclones provide for the lowest control efficiencies of the options at up to 65 percent, and particulate collection efficiencies of 85 percent or greater have been reported for venturi [wet] scrubbers operating on wood-fired boilers.[7] To achieve control efficiencies of 90 percent or greater, a baghouse or ESP is used. The normal PM control efficiency range for a fabric filter is 95 to 99+ percent, and the normal PM control efficiency range for a WESP is 98 to 99+ percent.[8] Fabric filters are rarely used on wood-fired boilers due to concerns about bag flammability.[9] The principal drawback is a fire danger arising from the collection of combustible carbonaceous fly ash.[10] Both types (i.e., wet and dry) of ESPs are capable of greater than 99 percent removal of particle sizes above 1 micron.[11] An additional benefit of WESPs is that the wash used in WESPs can also have some control effect on other pollutant gases via absorption and can help condense other emissions due to the cooling of the stream.[12] Based on the comparison of control efficiencies and the applicability of each control device, Domtar asserts that the WESP is the best control technology (i.e., BART) for the No. 1 Power Boiler.

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[6] Mike Bates (ADEQ), letter to Kelley Crouch (Domtar), September 8, 2006.

[7] U.S. EPA, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Source* (AP-42), Fifth Edition, Section 1.6 – Wood Residue Combustion in Boilers, September 2003.

[8] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

[9] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

[10] U.S. EPA, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Source* (AP-42), Fifth Edition, Section 1.6 – Wood Residue Combustion in Boilers, September 2003.

[11] Northeast States for Coordinated Air Use Management (NESCAUM) and Mid-Atlantic/Northeast Visibility Union (MANE-VU), *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

[12] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

4.2 BART DETERMINATION FOR SO_2 – NO. 1 POWER BOILER

Generally, pre-combustion SO_2 control strategies involve fuel switching/blending or fuel cleaning so that less fuel-bound sulfur enters the process. However, because wood already contains very little sulfur, pre-combustion SO_2 controls are ineffective.

Post-combustion SO_2 control is accomplished by reacting the SO_2 in the gas with a reagent (usually calcium-based [e.g., lime or limestone] or sodium-based [e.g., caustic]) and removing the resulting product (a sulfate/sulfite) for disposal or commercial use. SO_2 reduction technologies are commonly referred to as flue gas desulfurization (FGD) and/or scrubbers and are usually described in terms of the process conditions (wet versus dry), byproduct utilization (throwaway versus saleable) and reagent utilization (once-through versus regenerable).[13] Post-combustion SO_2 controls have not been installed on wood-fired boilers because of the relatively low SO_2 emissions from wood-combustion (due to the low sulfur content of wood).

Due to the low fuel sulfur input, emissions from wood combustion are inherently low and have a negligible impact on visibility impairment. Therefore, Domtar proposes no additional add-on control, i.e., only the existing fuel restrictions (fuel oil sulfur content and usage limitations) and no additional SO_2 removal as BART for SO_2 emissions from the No. 1 Power Boiler.

4.3 BART DETERMINATION FOR SO_2 – NO. 2 POWER BOILER

Section IV.D.1.9 of the BART Guidelines provides an option to skip the comprehensive BART determination analysis for BART-eligible emission units that are already equipped with the most stringent controls available (including any possible improvements to the control device) "as long these most stringent controls available are made federally enforceable for the purpose of implementing BART for that source." The Ashdown Mill's No. 2 Power Boiler is equipped with a wet scrubber for control of SO_2 (and particulate) emissions. The existing wet scrubber achieves an SO_2 control efficiency of approximately 90 percent, which is within the normal range for the highest efficiency SO_2 control strategies and is the BART-based control efficiency presumed by the Central Regional Air Planning Association (CENRAP) and the Midwest Regional Planning Organization (MRPO) for pulp and paper industry power boilers.[14,15]

The No. 2 Power Boiler is equipped with a CEMS for SO_2. Thus, Domtar is able to immediately identify needs for both ongoing operational adjustments and periodic maintenance and/or scrubber improvements to maintain high levels of SO_2 control. Domtar has not identified any feasible upgrades to the existing wet scrubber. It should be noted that the No. 2 Power Boiler is operated such that SO_2 emissions are well below any applicable limits/standards. Since wet scrubbing is the most effective method of controlling SO_2 emissions, no additional analysis is needed for SO_2 emissions from the No. 2 Power Boiler. Domtar proposes no additional SO_2 removal as BART for the No. 2 Power Boiler.

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[13] NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

[14] CENRAP's Control Estimates Spreadsheet dated January 10, 2006.

[15] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.

4.4 BART DETERMINATION ANALYSIS FOR NO_X

Each required step of the BART determination analysis for emissions of NO_X from the No. 1 and No. 2 Power Boilers is presented below.

4.4.1 STEP 1 - IDENTIFY ALL AVAILABLE RETROFIT CONTROL TECHNOLOGIES

The BART Guidelines require the consideration of all "control technologies with a practical potential for application to the emissions unit and the regulated pollutant under evaluation." The list of available control options should include "the most stringent option and a reasonable set of options for analysis…[, but] it is not necessary to list all permutations of available control levels that exist for a given technology – the list is complete if it includes the maximum level of control each technology is capable of achieving."

Per the BART Guidelines, the BART determination analysis must "take into account technology transfer of controls that have been applied to similar source categories and gas streams [in addition to] existing controls for the source category in question." However, "technologies which have not yet been applied to (or permitted for) full scale operations need not be considered as available; [the U.S. EPA does] not expect the source owner to purchase or construct a process or control device that has not already been demonstrated in practice." The BART Guidelines provides the following additional considerations for preparing the list of potential control options:

- One of the control options should reflect the level of control equivalent to any applicable NSPS,
- Source redesign should not be considered,
- Fuel switching should not be considered, and
- For emission units with existing control measures or devices, one of the control options should involve improvements to the existing controls.

Potential NO_X control technologies and resulting emission control quantities for the Ashdown Mill's No. 1 and No. 2 Power Boilers were identified from the exhaustive review of the U.S. EPA's Clean Air Technology Center, including the RACT/BACT/LAER Clearinghouse (RBLC), control equipment vendor information, publicly-available air permits and applications, and technical literature published by the U.S. EPA, the Regional Planning Organizations (RPOs), and industry groups such as the National Council for Air and Stream Improvement, Inc. (NCASI).[16] In fact, Domtar has largely relied upon the extensive research conducted by NCASI regarding the applicability and effectiveness of each control option for coal- and wood-fired pulp and paper mill power boilers. Each NO_X

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[16] *NCASI is an independent, non-profit research institute that focuses on environmental topics of interest to the forest products industry. NCASI was established in 1943…In the years since, NCASI has developed technical expertise spanning the spectrum of environmental challenges facing the forest products industry, and is today recognized as the leading source of reliable data on environmental issues affecting this industry.* (http://www.ncasi.org/about/default.aspx)

control option identified as potentially applicable to either power boiler is listed below and explained in detail in the following subsections.

- Selective Non-Catalytic Reduction (SNCR) / NO_XOUT
- Selective Catalytic Reduction (SCR)
- Low NO_X Burners (LNB) and Ultra Low NO_X Burners (ULNB)
- Over-fire Air (OFA)
- Reburning / Methane de-NO_X (MdN)
- Flue Gas Recirculation (FGR) (Internal and External)
- Fuel Blending / Boiler Operational Modifications / Tuning / Optimization

For this analysis, utility boiler control technology determinations were generally <u>not</u> considered since utility boilers and pulp and paper mill power boilers are considered too dissimilar.

> *The greatest difference in utility and power boiler operations is the fluctuating steam demand characteristic of pulp and paper mill operations which requires that power boilers continuously adjust fuel firing rates and excess air levels. Even with the most sophisticated combustion controls, it is not practical or safe to maintain excess air continuously at minimum levels. Consequently, power boilers have characteristically and inherently higher NO_X emissions.*
>
> *…NO_X reduction measures are particularly difficult to implement in small, low capacity facilities because a) residence time is limited and often inadequate for applying OFA without excessive loss of thermal efficiency or induced smoking; b) relatively small furnace dimensions limit combustion modifications that increase flame length and tend to cause the flame to impinge on tube wall;, c) peak boiler efficiency and minimized NO_X emissions occur close to minimum flue-gas O_2 content, which is at the threshold of smoke or combustible-emissions formation; d) steam is used far more effectively in industrial applications than in conventional electric utility plants and, consequently, emission limits based on boiler heat input or volume of flue gas do not recognize such efficiency.*[17]

Combustion-related NO_X emissions are formed by two mechanisms. NO_X formed from oxidation of molecular nitrogen (N_2) in combustion air is referred to as "thermal NO_X" and is dependent on high temperatures (approximately 2,800 °F) and an excess of combustion air. NO_X formed by oxidation of nitrogen compounds in fuel is referred to as "fuel NO_X." The NO_X formed from coal combustion is primarily fuel NO_X.[18] Fuel NO_X is also the dominant NO_X formation mechanism operative during wood combustion because wood combustion in boilers seldom reaches high enough temperatures.[19,20]

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[17] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[18] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

[19] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

The possible NO_X emissions control technologies generally fit into one of two categories: combustion modifications, which are often associated with improving boiler performance, or flue gas treatment (i.e., post-combustion controls). Pre-combustion techniques to reduce fuel NO_X have shown little promise.[21] Combustion modifications are the most common, commercially available means of controlling NO_X emissions from fossil fuel-fired boilers.[22] However, since wood-fired boilers normally burn at lower temperatures (around 1,500 °F), the units have inherently lower NO_X emissions, and, as a result, NO_X combustion control technologies are not applicable to wood-fired boilers.[23] During the past decade, LNB with FGR and LNB alone were the most commonly recommended NO_X control technologies for oil/gas and coal-fired boilers, respectively, while good combustion control was typically the only recommendation for wood waste-fired boilers.[24]

COMBUSTION MODIFICATIONS

4.4.1.1 FLUE GAS RECIRCULATION

Generally, FGR involves extracting a portion (15 to 30 percent) of the flue gas and readmitting it to the furnace through the burner window. When the flue gas is extracted from the economizer or air heater outlet, a separate fan/blower is needed to withdraw the flue gas. This setup is referred to as external or forced FGR. Internal or induced FGR refers to the setup where the flue gas is extracted from upstream of the stack using the forced draft (FD) fan instead of a separate FGR fan. In either setup, the recirculated flue gas acts as a thermal diluent (i.e., heat sink) to reduce combustion temperatures. It also dilutes the combustion reactants and reduces the excess air requirements thereby reducing the concentration of oxygen in the combustion zone. Thus, thermal NO_X formation is inhibited.[25] The onset of thermal NO_X occurs around 2,800 °F, and NO_X generation increases exponentially with temperatures beyond 2,800 °F. As only thermal NO_X can be controlled by this technique, it is especially effective only in oil and gas-fired units.[26]

4.4.1.2 LOW NO_X BURNERS / ULTRA LOW NO_X BURNERS

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, flame temperature, and/or residence time. A

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[20] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[21] Ibid.

[22] Ibid.

[23] STAPPA and ALAPCO, *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, March 2006.

[24] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[25] U.S. EPA, Clean Air Technology Center, *Nitrogen Oxides (NO_X), Why and How They Are Controlled*. Research Triangle Park, North Carolina, EPA-456/F-99-006R, November 1999.

[26] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

LNB is a staged combustion process that is designed to split fuel combustion into two zones, primary combustion and secondary combustion. Two general types of LNB exist: staged fuel and staged air. Lower emission rates can be achieved with a staged fuel burner than with a staged air burner. Staged fuel LNB separate the combustion zone into two regions. The first region is a lean primary combustion region where the total quantity of combustion air is supplied with a fraction of the fuel. Combustion in the primary region (first stage) takes place in the presence of a large excess of oxygen at substantially lower temperatures than a standard burner. In the second region, the remaining fuel is injected and combusted with any oxygen left over from the primary region. The remaining fuel is introduced in the second stage outside of the primary combustion zone so that the fuel/oxygen are mixed diffusively (rather than turbulently), which maximizes the reducing conditions. This technique inhibits the formation of thermal NO_X, but has little effect on fuel NO_X. By increasing residence times staged air LNB provide reducing conditions, which have a greater impact on fuel NO_X than staged fuel burners. The estimated NO_X control efficiency for LNB in high temperature applications is 25 percent.[27]

The application of LNB is often limited by the longer flames produced as a consequence of improved air distribution control. While there is generally ample room for LNB flames in utility furnaces, their use on smaller power boilers can result in flame impingement on furnace walls, leading to tube wall overheating and mechanical failure. Flame impingement can also result in premature flame quenching and increased soot and CO emissions.[28]

ULNB combine LNB and FGR technologies and may incorporate other techniques such steam injection. The FGR design within ULNB recirculates flue gas from the flame or firebox back into the combustion zone in an effort to reduce oxygen concentrations without significantly reducing flame temperature. Reduced oxygen concentrations in the flame have a strong impact on fuel NO_X.[29] ULNB also tend to have large diameters, but shorter flame lengths and may be easier to retrofit.[30]

Combustion modification with LNB is used in both gas/oil-fired and coal-fired units.[31] LNB are not used for wood-fired boilers. The No. 1 Power Boiler burns only a small amount of fuel for which LNB technology exists. Therefore, LNB is not considered further for the No. 1 Power Boiler.

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[27] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

[28] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[29] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

[30] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[31] Ibid.

4.4.1.3 OVERFIRE AIR

In OFA, about 10 to 20 percent of the combustion air flow is directed to separate air ports located downstream of the burners. OFA works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect and theoretically reducing NO_X emissions. Residual unburned material, such as CO and unburned carbon, which inevitably escapes the main burner zone, is oxidized as the OFA is admixed later.[32]

OFA vendors (e.g., Jansen Combustion and Boiler Technologies, Inc.) have informed Domtar that while OFA often results in decreased NO_X emissions, the primary purpose is combustion optimization, and implementation of OFA can actually increase NO_X emissions in certain circumstances. Domtar has experienced this potential adverse effect. A recent OFA upgrade to the Ashdown Mill's No. 3 Power Boiler (not a BART-eligible unit) is still in startup mode, but so far Domtar has measured a noteworthy increase in NO_X emissions.

Domtar does not consider OFA to be a potential NO_X control technology, and OFA is not considered further in this analysis.

4.4.1.4 REBURNING / METHANE DE-NO_X

In reburning, also known as "off-stoichiometric combustion" or "fuel staging," a fraction (5 to 25 percent) of the total fuel heat input is diverted to a second combustion zone downstream of the primary zone. The fuel in the fuel-rich secondary zone acts as a reducing agent, reducing NO, which is formed in the primary zone, to N_2. Low nitrogen-containing fuels such as natural gas and distillate oil are typically used for reburning to minimize further NO_X formation. Generally, it is more economical for a facility to use the same fuel for reburning as it does for primary combustion, although there are exceptions. In order to use coal as a reburning fuel, it must be finely ground, which requires additional pulverizing equipment.[33]

MdN utilizes the injection of natural gas together with recirculated flue gases (for enhanced mixing) to create an oxygen-rich zone above the combustion grate. Air is then injected at a higher furnace elevation to burn out the combustibles. This process is claimed to yield between 50 and 70 percent NO_X reduction and to be suitable for all solid fuel-fired stoker boilers. However, as of 2002, MdN had only been demonstrated for a short duration in one pulp mill wood-fired stoker boiler that also burned small amounts of waste treatment plant residuals, with NO_X reductions of 40 to 50 percent reported.[34]

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[32] Ibid.

[33] STAPPA and ALAPCO, *Controlling Fine Particulate Matter Under the Clean Air Act: A Menu of Options*, March 2006.

[34] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

More recently, MdN is being applied to kraft pulp mill stoker boilers by utilizing the VOC content of NCGs to partially replace the natural gas (by up to 25 percent). This technology has been tested for over a year at one pulp mill boiler, and is being tested at several boilers within one forest products industry (FPI) company.[35]

4.4.1.5 FUEL BLENDING

Since wood is inherently low in nitrogen content, fuel blending is not feasible for wood-fired boilers. Therefore, this control strategy is not considered for the Ashdown Mill's No. 1 Power Boiler.

Coal-fired boilers could experience a decrease in NO_X emissions from fuel blending. Preliminary results show that the co-firing of up to 7 percent biomass, on a heat-input basis, with crushed or pulverized coal can lower NO_X emissions by as much as 15 percent.[36] However, fuel biasing on an industrial boiler subject to rapid and excessive load swings could result in too rich or too lean firing conditions, which can lead to flame stability problems and explosive conditions.[37] In addition, unlike utilities, which can specify the nitrogen content of their large oil purchases, most industrial mills cannot.[38]

Domtar historically mixes 10 to 15 percent (heat input basis) wood with coal in the No. 2 Power Boiler. Therefore, fuel blending is considered part of the base case for the No. 2 Power Boiler.

4.4.1.6 BOILER OPERATIONAL MODIFICATIONS / TUNING / OPTIMIZATION

Combustion optimization efforts can lead to improvements in NO_X emissions of 5 to 15 percent. Recent developments of intelligent controls – software-based systems that "learn" to operate a unit and then maintain its performance during normal operation – are expected help in keeping plants well tuned.[39] Domtar has employed, and will continue to employ, the latest boiler optimization and tuning techniques. This control strategy is considered part of the base case for the Ashdown Mill's No. 1 and No. 2 Power Boilers.

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[35] Ibid.

[36] Ibid.

[37] Ibid.

[38] Ibid.

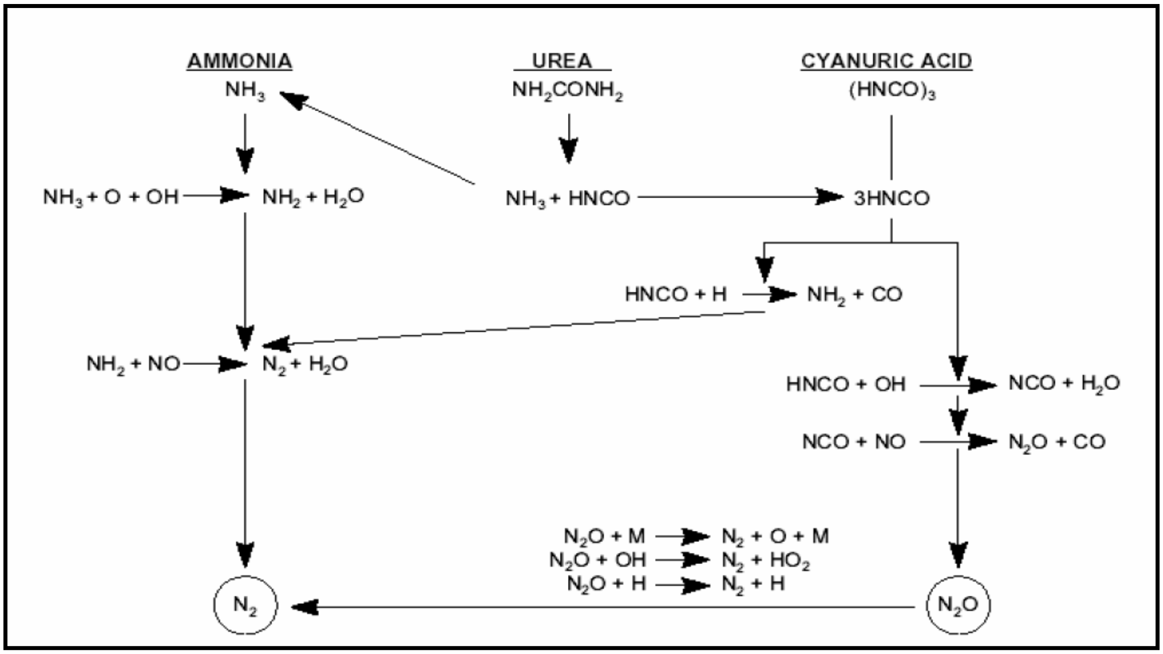
[39] NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

POST-COMBUSTION CONTROLS

4.4.1.7 SELECTIVE NON-CATALYTIC REDUCTION

SNCR is a post-combustion NO_X control technology based on the reaction of urea or ammonia (NH_3) and NO_X. In the SNCR chemical reaction, urea or ammonia-based chemicals are injected into the combustion gas path to reduce the NO_X to nitrogen and water. The primary SNCR reaction sequences are shown in Figure 4-1.[40]

FIGURE 4-1. PRIMARY SNCR REACTION SEQUENCES



Typical NO_X removal efficiency for SNCR is 30 to 65 percent. For industrial coal-fired boilers, SNCR can achieve approximately 40 percent NO_X control.[41] An important consideration for implementing SNCR is the operating temperature range. The optimum temperature range is approximately 1,600 to 2,000 °F.[42] Operation at temperatures below this range results in ammonia slip. Operation above this range results in oxidation of ammonia, forming additional NO_X. In addition, the urea must have sufficient residence time, about 3 to 5 seconds, at the optimum operating temperatures for efficient NO_X reduction. Therefore, the injection point is typically prior to convective heat recovery.[43]

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[40] ABB Power Plant Laboratories, *Engineering development of coal-fired high performance power systems – Phase II topical report*, Selective Non-Catalytic Reduction System Development Subcontract to United Technologies Research Center, Contract No. DE-AC22-95PC95144, February 24, 1997 (reprinted in NCASI's Special Report No. 03-04).

[41] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.

[42] U.S. EPA, Clean Air Technology Center, *Nitrogen Oxides (NO_X), Why and How They Are Controlled*. Research Triangle Park, North Carolina, EPA-456/F-99-006R, November 1999.

[43] U.S. EPA. *Summary of NO_X Control Technologies and their Availability and Extent of Application*. Research Triangle Park, North Carolina. EPA-450/3-92-004, February 1992.

According to the U.S. EPA, the performance of an SNCR system is affected by six factors.

> *These are a) inlet NO_X level, b) temperature, c) mixing, d) residence time, e) reagent-to- NO_X ratio, and f) fuel sulfur content. Lower inlet NO_X concentrations reduce the reaction kinetics and hence the achievable NO_X emissions reductions. As mentioned above, temperatures below the desired window result in ammonia emissions (slip), and temperatures above the desired window result in NH_3 being oxidized to NO_X. Mixing becomes an important consideration in regions distant from an injection nozzle where the level of turbulence is reduced and stratification of the reagent and flue gas will probably be a greater problem, especially at low boiler loads. Residence time becomes important to allow the desired reactions to go to completion. Small, packaged, water tube boilers and boilers with varying steam loads are therefore difficult applications for SNCR. As higher than the theoretical NH_3 to NO_X ratios are generally required to achieve desired NO_X emission reductions, a trade-off exists between NO_X control and the presence of NH_3 in the flue gas. The main disadvantage of SNCR is the low NO_X reduction that is experienced when the allowable ammonia slip is low. Finally, in the case of high sulfur fuels, excess NH_3 can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit on downstream equipment leading to plugging and reduced heat transfer efficiencies.*[44]

One concern about the SNCR process is its ability to perform adequately under changing load and fuel conditions.[45] Based on its research regarding this concern, NCASI concludes that SNCR is most widely used for base-loaded boilers, and is not suited for power boilers that experience wide temperature variances, i.e., high load swings. NCASI also points out that the use of SNCR systems on coal-fired boilers is still in the development stage.[46]

The NO_XOUT process is an SNCR hybrid based on the following chemical reaction that ideally occurs in the temperature range of 1700 to 2000 °F:

$$2\ NO + NH_2CONH_2 + 1/2\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$

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[44] U.S. EPA, *New source performance standards, subpart Db – technical support for proposed revisions to NO_X*, EPA-453-/R-95-012 (republished in NCASI's Special Report 03-04).

[45] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[46] Ibid.

The problems with typical SNCR systems (e.g., ammonia slippage and heat transfer surface fouling with byproduct formation) also exist with the NO_XOUT process.

4.4.1.8 SELECTIVE CATALYTIC REDUCTION

SCR is a post-combustion gas treatment process in which NH_3 is injected into the exhaust gas in the presence of a catalyst bed usually located between the boiler and air preheater. The catalyst lowers the activation energy required for NO_X decomposition.[47] On the catalyst surface, NH_3 and nitric oxide (NO) react to form diatomic nitrogen and water. The overall chemical reaction can be expressed as:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$

When operated within the optimum temperature range of approximately 575 to 750 °F, the reaction can result in removal efficiencies between 70 and 90 percent. For coal-fired industrial boilers, SCR can achieve approximately 80 percent NO_X control.[48] The specific temperature ranges are 600 to 750 °F for conventional (vanadium or titanium) catalysts, 470 to 510 °F for platinum catalysts, and 600 to 1000 °F for high-temperature zeolite catalysts.[49] SCR units have the ability to function effectively under fluctuating temperature conditions (usually ± 50 °F), although fluctuation in exhaust gas temperature reduces removal efficiency by disturbing the chemical kinetics (speed) of the NO_X -removal reaction.

According to the U.S. EPA, the performance of an SCR system is affected by six factors.

> *These are a) NO_X level at SCR inlet, b) flue gas temperature, c) NH_3-to-NO_x ratio, d) fuel sulfur content, e) gas flow rate, and f) catalyst condition. For SCR, when inlet NO_X concentrations fall below 150 ppm, the reduction efficiencies decrease with decreasing NO_X concentrations. Each type of catalyst has an optimum operating temperature range. Temperatures below this range result in ammonia emissions (slip), and temperatures above the desired range result in NH_3 being oxidized to NO_X. For up to about 80 percent NO_X reduction efficiencies, a 1:1 NH_3:NO_X ratio is sufficient. For higher efficiencies, higher reagent to NO_X ratios are required which may result in higher NH_3 slip. In the case of high sulfur fuels, excess NH_3 can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit and foul downstream equipment. SCR application experience in the case of*

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[47] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.
[48] MRPO, *Interim White Paper – Midwest RPO Candidate Control Measures*, March 29, 2005.
[49] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

> *medium-to-high sulfur fuels is limited. For a given flue gas flow rate, the catalyst structural design should be chosen so that the residence time needed for the reduction reactions to take place on the catalyst surface is achievable.*[50]

4.4.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Per the BART Guidelines, documentation of infeasibility should "explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option under review." The BART Guidelines use the two key concepts of "availability" and "applicability" to determine if a control option is technically feasible. These concepts are defined in Section IV.D.2:

> *…a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration.*
>
> *The typical stages for bringing a control technology concept to reality as a commercial product are:*
> - *concept stage;*
> - *research and patenting;*
> - *bench scale or laboratory testing;*
> - *pilot scale testing;*
> - *licensing and commercial demonstration; and*
> - *commercial sales.*
>
> *A control technique is considered available, within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as "available" for purposes of BART review.*
>
> *In general, a commercially available control option will be presumed applicable if it has been used on the same or a similar source type. Absent a showing of this type, you evaluate technical feasibility by examining the physical and chemical characteristics of the pollutant-bearing gas stream, and comparing them to the gas stream characteristics of the source types to which the technology had been applied previously.*

COMBUSTION MODIFICATIONS

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[50] U.S. EPA, *New source performance standards, subpart Db – technical support for proposed revisions to NO_X*, EPA-453-/R-95-012 (republished in NCASI's Special Report 03-04).

4.4.2.1 FLUE GAS RECIRCULATION

FGR is used to reduce thermal NO_X formation. Emissions due to fuel-bound NO_X, which are significant for coal-fired boilers, are not meaningfully affected by FGR. Therefore, FGR is not technically feasible to control NO_X emissions from coal-fired boilers.[51] Similarly, FGR would not be effective in wood combustion since most of the NO_X generated during wood combustion is also from the fuel NO_X pathway.[52] Recent refusals by vendors (e.g., Entropy Technology & Environmental Consultants LP[53]) to provide budgetary estimates for installing FGR are further evidence that FGR is not applicable for the Ashdown Mill's No. 1 and No. 2 Power Boilers.

4.4.2.2 REBURNING / METHANE DE-NO_X

Generally, Domtar considers MdN not feasible because (1) it is not fully demonstrated and (2) it incorporates FGR, which is clearly technically infeasible (see Section 4.4.2.1). However, Domtar was able to obtain equipment cost estimates from vendors of MdN. Therefore, MdN is considered further in this analysis.

POST-COMBUSTION MODIFICATIONS

NCASI points out the following issues of concern for post-combustion NO_X controls (i.e., SNCR and SCR) for pulp and paper mill power boilers:[54]

> **Load Swings -** Pulp mill combination and power boilers frequently exhibit wide and rapid load swings that are not consistent with the steady conditions required for effective use of either SNCR or SCR NO_X control technologies. The load swings produce variable temperature conditions in the boiler, causing the temperature zone for NO_X reduction to fluctuate, making it more difficult to know where to inject the reactants.
>
> **Temperature Incompatibility -** Combination and power boilers are affected by temperature profile incompatibility. To obtain the required temperature window, the only location to install this technology is upstream of the particulate matter control device, yet this is where flue gases are dirty and can foul the catalyst rapidly.

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[51] U.S. EPA. *Alternative Control Technologies Document: NO_X Emissions from Utility Boilers.* (EPA-453/R-94-023).

[52] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[53] Steve Wood (ETEC), e-mail to Joel Martin (Domtar), September 20, 2006: "Based on the design and operational data provided regarding #2 Coal Boiler, ETEC would decline to bid the application Induced Flue Gas Recirculation for Boiler #2 NO_X control. Flue gas recirculation technology is very effective in reducing natural gas and light oil fuel NO_X emissions, but is not for No.6 fuel oil, coal, bark and other solid fuels. To the best of our knowledge, flue gas recirculation for NO_X control has never been installed on a coal fired boiler."

[54] Ibid.

> Downstream of the PM control device, the temperature is too low for the catalyst to be effective.
>
> **Unproven** – SCR or SNCR controls, technologies which, for the most part, are untested and infeasible for pulp and paper mill boilers. These technologies must be operated on a continuous basis within a specified temperature range in order to be effective. The type of fuel burned influences the design of the technology, and FPI facilities' frequent fuel changes and co-firing of multiple fuels would result in design and operational problems.
>
> **Lack of Guarantee for FPI Boilers** – Boiler owners are finding that vendors of SCR and SNCR technologies are unwilling to provide performance guarantees that the controls will meet the level of reduction called for in [NSPS Subpart Db (promulgated on September 16, 1998)].

4.4.2.3 SELECTIVE NON-CATALYTIC REDUCTION

Most boilers in the pulp and paper industry operate in the swing load mode, a consequence of supplying steam as required to the various components of the process. The problem with control of the required flue gas temperature window is an inherent difficulty with use of SNCR for load-following boilers, whether wood or fossil fuel.[55]

Controlling flue gas temperatures over the entire range of operating loads that the boiler is expected to experience will be very difficult to achieve. Boilers in the pulp and paper industry rarely operate under base loaded conditions. Consequently, the location of the desired temperature window is expected to change constantly. Accurate, instantaneous temperature measurement, as well as the ability to accurately adjust the location of the injection nozzle, would be necessary. Ammonia slip would be a recurring problem associated with the application of the SNCR process to industrial boilers with fluctuating loads.[56]

Inadequate reagent dispersion in the region of reagent injection in wood-fired boilers is also a factor mitigating against the use of SNCR technology.[57] Good dispersion of the reagent in the flue gas is needed to get good utilization of the reagent and to avoid excessive ammonia slip from the process. The need for a

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[55] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for* NO_X*,* SO_2 *and PM Emissions*, Corporate Correspondence Memo 06-014.

[56] NCASI, NO_X *Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[57] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for* NO_X*,* SO_2 *and PM Emissions*, Corporate Correspondence Memo 06-014.

sufficient volume in the boiler at the right temperature window precludes the application of SNCR in all types of industrial boilers.[58]

Additional issues with SNCR include the potential for formation of ammonium sulfate salts (if sulfur oxides are present in the gas stream where they can react with excess ammonia from the SNCR process to form ammonium salts), which cause plugging problems. Ammonia also poses potential water quality issues - ammonia slip released to the atmosphere could contaminate surface waters by deposition.

SNCR has been applied to a few base-loaded wood and combination wood-fired boilers, mainly in the electric generating industry. However, its efficacy on wood-fired boilers with changing loads has not been demonstrated, except when used as a polishing step. Early use of ammonia injection in the case of one pulp mill wood-fired boiler met with significant problems and had to be abandoned (significant ammonia slip, caused by inefficient dispersion of the reagent within the boiler, was to blame). The boiler was unable to meet the manufacturer guarantee unless operated at less than half load. Even then, reducing NO_X to near permitted limits consumed considerably more ammonia than anticipated, leading to the formation of a visible ammonium chloride plume. A similar problem was encountered at a second FPI mill where nearly half the urea (on a molar basis) injected was being emitted as ammonia.[59]

The use of SNCR on stoker type wood-fired boilers that have significant load swings has not been demonstrated. Excessive ammonia slip is a primary concern when adequate dispersion of the SNCR chemical is not achieved in the boiler ductwork within the range of residence times available and temperatures needed for the NO_X reduction reactions to go to completion. Additional concerns include the impact of interference from higher CO levels present in many wood-fired boilers, the possibility of appreciable SNCR chemical being absorbed onto the ash matrix in a wood-fired boiler, and the extent and fate of ammonia in scrubber purge streams.[60]

The MRPO concludes, “if combustion zone temperatures within the boiler do not fall into [the ideal temperature range], then SNCR would be infeasible.”[61]

4.4.2.4 SELECTIVE CATALYTIC REDUCTION

The use of SCR on boilers operating in the FPI has also never been successfully demonstrated for wood boilers, and would face the same inherent problem of requiring it to be post PM-control to protect the catalyst, and

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[58] NESCAUM and MANE-VU, *Assessment of Control Technology Options for BART-Eligible Sources – Steam Electric Boilers, Industrial Boilers, Cement Plant and Paper and Pulp Facilities*, March 2005.

[59] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[60] Ibid.

[61] MACTEC, *Midwest RPO Boiler BART Engineering Analysis*, March 30, 2005.

achieving and maintaining the required temperature window for effective NO_X control.[62] There are numerous other issues with using SCR including catalyst plugging and soluble alkali poisoning as well as increased energy consumption.[63]

The use of SCR technology would be considered technically infeasible based upon the fact that post-particulate removal flue gas temperatures are typically significantly lower than those desired for this application. Many boilers are equipped with wet scrubbers for particulate emission (PM) control. Reheating the scrubbed flue gases from these boilers to bring them within the desired temperature window would involve a significant energy penalty. For pre-particulate removal flue gas application, catalyst deactivation from high particulate loading would be a serious concern, in addition to the impact of fluctuating loads on flue gas temperatures. Deactivation and/or poisoning could result from the size and density of fly ash particulate, and from their unique chemical and physical nature. Water-soluble alkali (such as Mg or Na) in particulate-laden gas streams has been known to poison SCR catalysts. Space considerations for installing a catalyst section in an existing boiler's ductwork are also important. Also note the use of solid fuels can result in catalyst contamination even with efficient PM control system and high moisture levels in exhaust air would result in inefficient SCR operation.[64]

Most boilers feature a flue gas temperature at the economizer exit that is below the ammonium sulfate/bisulfate dew point. Air heater surfaces must withstand corrosion from ammonium sulfates and bisulfates, be easily cleaned with conventional soot blowing, and survive corrosion-inducing water washing. SO_3 produced by the catalyst may condense on cooler surfaces, depending on the temperature, during both steady-state and non-steady-state operation. Higher levels of SO_2 to SO_3 conversion could cause accelerated corrosion or higher SO_3-induced plume opacity. Minimizing ammonia levels in the stack (typically <2 to 3 ppm) is required to avoid problems with disposal of scrubber byproduct contaminated by ammonia. The use of a particular catalyst puts restrictions on the fuel flexibility for a boiler. For example, purchasing coal with fly ash containing calcium oxide and arsenic outside the defined range absolves the catalyst supplier from responsibility for arsenic poisoning.[65]

The only "wood-fired" boiler SCR application in service in the U.S. was located at a woodworking facility in Ohio. This SCR was located downstream of a mechanical collector and electrostatic precipitator, operating in flue gas temperatures ranging from 550 to 650 °F. The only problem reported at this

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[62] NCASI, *Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_X, SO_2 and PM Emissions*, Corporate Correspondence Memo 06-014.

[63] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.

[64] Ibid.

[65] Ibid.

installation was minor catalyst blinding due to the deposition of fine particulate that escaped the PM collection devices. It was learned the operating temperature for this SCR system allowed the use of conventional catalysts designed to accommodate high dust applications. For these catalysts, the catalyst openings through which the flue gas flows are sized to provide proper surface area contact and sufficient flue gas velocity to minimize fouling. Low temperature catalyst designs are considerably different and would not be recommended for use on any high dust application. Based on this description of the air pollution control system configuration and the operating conditions for this particular wood-fired boiler, it is important to identify several specific differences between this installation and those that operate in the FPI. First, due to the requirement to provide hot air to burn all but the driest of wood fuels, wood-fired boilers are usually equipped with air preheaters. Thus, even when dry particulate control devices like an ESP are utilized, the installation of an SCR catalyst section after a PM control device is not amenable for adaptation to such boilers without, of course, incurring a severe energy penalty. Second, a significant portion of the FPI's wood-fired boilers is controlled for PM emissions by multiclones and wet scrubbers. Therefore the PM emissions from these would be higher than the example situation. Third, it is unclear how the Ohio facility's SCR system would have worked under the fluctuating boiler load characteristics common to many FPI boilers. Finally, sawdust, which was the fuel fired in the Ohio facility's boiler, is a low moisture fuel and the particulate matter present in the flue gases from its combustion is likely to be of different composition than when bark or hog fuel (typically much higher moisture) is burned.[66]

Hence the use of SCR technology has clearly not been demonstrated for industrial wood, biomass or combination fuel-fired boilers in the FPI.[67]

4.4.3 STEP 3 – EVALUATE CONTROL EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

Table 4-2 presents a ranking of the technically feasible control strategies in order of their effectiveness (i.e., potential control efficiency). For controls with a range of performance levels, the BART Guidelines note:

> *It is not [the U.S. EPA's] intent to require analysis of each possible level of efficiency for a control technique as such an analysis would result in a large number of options. It is important, however, that in analyzing the technology you take into account the most stringent emission control level that the technology is capable of achieving.*

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[66] Ibid.

[67] Ibid.

TABLE 4-2. RANKING OF CONTROL STRATEGIES

Control Strategy	Applicability	Potential Control Efficiency (%)
MdN	No. 1 & No. 2 Boilers	50 [a]
LNB	No. 2 Boiler Only	30 [b,c]
Original OFA + Boiler Tuning/Optimization	No. 1 Boiler	Base Case
Original OFA + NO_X Air + Fuel Blending + Boiler Tuning/ Optimization	No. 2 Boiler	Base Case

[a] Based on estimate from Energy System Associates.
[b] NCASI, *NO_X Control in Forest Products Industry Boilers: A Review of Technologies, Costs and Industry Experience*, Special Report 03-04.
[c] Based on estimate from B&W.

Note that MdN is included in Table 4-2 despite its questionable technical feasibility.

4.4.4 STEP 4 – EVALUATE IMPACTS AND DOCUMENT RESULTS

The technically feasible control technologies are evaluated on the basis of (1) costs of compliance, including consideration of the remaining useful life, (2) energy impacts, and (3) non-air quality environmental impacts.

For the purposes of this analysis, energy and non-air quality environmental impacts are considered minimal for all the technically feasible control options listed in Table 4-2. Per the BART Guidelines, the costs of compliance analysis for each control option consists of comparisons of the average cost effectiveness and the incremental cost effectiveness, which are defined in Section IV.D.4 as follows:

> *Average cost effectiveness means the total annualized costs of control divided by the annual emissions reduction (the difference between baseline annual emissions and the estimate of emissions after controls), using the following formula:*
>
> *Average cost effectiveness (dollars per ton removed) = Control option annualized cost ÷ (Baseline annual emissions – Annual emissions with Control option)*
>
> *…the incremental cost effectiveness calculation compares the costs of performance level of a control option to those of the next most stringent option, as shown in the following formula (with respect to cost per emissions reduction):*
>
> *Incremental Cost Effectiveness (dollars per incremental ton removed) = (Total annualized costs of control option) – (Total annualized costs of next control*

option) ÷ (Control option annual emissions) – (Next control option annual emissions)

The average and incremental (where applicable) cost effectiveness for each feasible control option for the Ashdown Mill's No. 1 and No. 2 Power Boilers are summarized in Table 4-3. Detailed control costs calculations are presented in Appendix B.

TABLE 4-3. CONTROLS COSTS SUMMARY

Emission Unit	Control Strategy	Total Annualized Cost (MM$)	NO_X Removed (tpy)	Cost Effectiveness Average ($/ton)	Cost Effectiveness Incremental ($/ton)
No. 1 Power Boiler	MdN	3.94	542	7,262	17,354
No. 2 Power Boiler	MdN	5.35	1,257	4,259	9,571
	LNB	1.10	754	1,465 [b]	N/A

[b] This estimate is consistent with NCASI's Special Report 03-04, which states, "for pulverized coal boilers, a 30 percent NO_X reduction could be achieved with LNB at a cost of <$2,000/ton."

Based on Domtar's analysis, MdN is considered cost prohibitive for both the No. 1 and No. 2 Power Boilers and is ruled out as a BART option. Based on steps 1 through 4 of the BART determination analysis, no retrofit controls are available for the No. 1 Power Boiler and LNB is the best available retrofit control technology for the No. 2 Power Boiler.

PROPOSED BART DETERMINATIONS FOR NO_X

For the No. 1 and No. 2 Power Boilers, Domtar proposes NO_X BART limits of 179.6 lb/hr and 368.7 lb/hr, respectively.

A summary of all proposed BART determinations is provided in Table 4-4. Please note that while example control technologies theoretically capable of achieving the proposed BART limits are listed, Domtar reserves the right to implement other equivalent control strategies between now and the BART effective date (~2013) to meet the same emission limits.

TABLE 4-4. SUMMARY OF PROPOSED BART DETERMINATIONS

Emission Unit	**Pollutant**	**BART Limit**	***Example Control Technology***
No. 1 Power Boiler	PM	0.07 lb/MMBtu (Boiler MACT)	*WESP*
	SO_2	442.5 lb/hr	*No additional add-on controls (existing fuel restrictions)*
	NO_X	179.6 lb/hr	*No add-on controls*
No. 2 Power Boiler	PM	0.07 lb/MMBtu (Boiler MACT)	*Wet Scrubber*
	SO_2	788.2 lb/hr	*Wet Scrubber*
	NO_X	368.7 lb/hr (30 Percent Control)	*LNB*

4.5 STEP 5 – EVALUATE VISIBILITY IMPACTS

The degree of visibility improvement is assessed based on the change in modeled impacts for the pre-control (i.e., the BART applicability analysis) and post-control (i.e., the predicted maximum 24-hour emission rate after implementation of BART) emission scenarios. Per the BART Guidelines, this assessment "may consider the frequency, magnitude, and duration components of [visibility] impairment."

The post-control modeling for the visibility improvement analysis was conducted using the CALPUFF modeling system in the same manner as the ADEQ's BART applicability analysis, which is described in Section 3 of this report and in the Protocol (see Appendix A). In fact, the post-control modeling was conducted using the same CALPUFF, POSTUTIL, and CALPOST input files generated by the ADEQ for the applicability analysis. The only changes made to these files for the post-control modeling was to the emissions rates and stack parameter changes associated with implementing the chosen BART controls. Table 4-5 and Table 4-6 summarize the maximum 24-hour average emission rates and the stack parameters, respectively, that were modeled in the post-control analysis.

TABLE 4-5. SUMMARY OF 24-HOUR AVERAGE MAXIMUM POST-CONTROL EMISSION RATES

Emission Unit	NO_X Emissions (lb/hr)	SO_2 Emissions (lb/hr)	Total PM Emissions (lb/hr)
No. 1 Power Boiler	179.6	442.5	40.6
No. 2 Power Boiler	368.7	788.2	57.4

TABLE 4-6. POST-CONTROL STACK PARAMETERS

Emission Unit	LCC East (km)	LCC North (km)	Elevation (m)	Stack Height (m)	Stack Diameter (m)	Exhaust Temperature (K)	Exhaust Velocity (m/s)
No. 1 Power Boiler	267.47491	-698.66686	97.5	66.1	1.890	522	26.76
No. 2 Power Boiler	267.48245	-698.74355	97.5	71.6	3.659	325	11.92

Visibility improvement is quantified and judged in a cumulative matter. That is, to compare to the pre-control modeling analysis executed by the ADEQ, Domtar's post-control modeling analysis simulated all emissions reductions from both emission units. Note that since maximum applicability analysis impacts were less than 0.5 Δdv for the Sipsey Class I area, this area was not evaluated in the post-control scenario. Table 4-7 summarizes the results of the visibility improvement analysis.

TABLE 4-7. SUMMARY OF VISIBILITY IMPROVEMENT ANALYSIS RESULTS

Class I Area	Maximum 24-hour Impact (Δdv) [a]	Number of Days > 0.5 Δdv [a]	Number of Days > 1.0 Δdv [a]
Caney Creek	2.039	118	29
Upper Buffalo	1.029	14	1
Mingo	0.836	2	0
Hercules-Glades	0.631	2	0

[a] For total modeled period: years 2001, 2002, and 2003.

As shown in Table 4-7, the application of BART on the Ashdown Mill's No. 1 and No. 2 Power Boilers results in significant visibility impacts improvement in the affected Class I areas. Visibility impairment at Upper Buffalo was reduced by 29 percent while impairment at Caney Creek was reduced by 32 percent (based on total impact and excluding any days with impacts less than 0.50 Δdv). The number of days within the modeled three-year period with impacts greater than 0.50 Δdv decreased from 159 to 118 for the Caney Creek Class I area and from 18 to 14 for the Upper Buffalo Class I area.

In addition to the cumulative analysis, the ADEQ requested emission unit specific and pollutant specific modeling. Since cumulative analysis impacts in the Upper Buffalo and Mingo Class I areas are minimal, the emission unit and pollutant specific modeling was only conducted for the Caney Creek Class I area. The results of these pre- and post-control analyses (each conducted for the entire modeling period: year 2001, 2002, and 2003) are presented in Table 4-8.

TABLE 4-8. EMISSION UNIT & POLLUTANT SPECIFIC MODELING RESULTS

Emission Unit	Pollutant	Pre-Control Scenario		Post-Control Scenario	
		Max. 24-hour Impact (Δdv)	Number of Days > 0.5 Δdv	Max. 24-hour Impact (Δdv)	Number of Days > 0.5 Δdv
No. 1 Power Boiler	PM	0.252	0	0.065	0
	SO_2	0.575	2	0.575	2
	NO_X	0.398	0	0.398	0
No. 2 Power Boiler	PM	0.135	0	0.095	0
	SO_2	1.036	5	1.036	5
	NO_X	1.072	35	0.762	14
No. 1 & 2 Power Boilers	PM	0.391	0	0.156	0
	SO_2	1.542	30	1.542	30
	NO_X	1.427	54	1.129	36

Additionally, as requested by the ADEQ in its September 8, 2006, letter, Domtar's post-control (and pre-control, where different from the ADEQ's applicability modeling files) CALPUFF, POSTUTIL, and CALPOST input files and CALPOST output files are included with this report on electronic media. The file naming convention is explained below. Note that all filenames contain the "doas" root (characters 4 through 7) to denote Domtar – Ashdown. Note also that path names will need to be modified to represent the user's directory structure when replicating these analyses.

File Naming Convention:

CALPUFF & POSTUTIL xx_doasyy(v*).fff

xx = Model: cp = CALPUFF
pu = POSTUTIL

yy = Year: 01 = 2001
02 = 2002
03 = 2003

*v** = Pollutant Run Identifier A = PM Pre-controls
B = PM Post-controls
C = SO_2 Pre- and Post-controls
D = NO_X Pre-controls
E = NO_X Post-controls

fff = File type: inp = Input

CALPOST xx_doasyyz(v*).fff

xx = Model: ct = CALPOST

yy = Year: 01 = 2001
02 = 2002
03 = 2003

z = Class I area: c = Caney Creek
m = Mingo
u = Upper Buffalo
h = Hercules-Glades
s = Sipsey

*v** = Pollutant Run Identifier A = PM Pre-controls
B = PM Post-controls
C = SO_2 Pre- and Post-controls
D = NO_X Pre-controls
E = NO_X Post-controls

fff = File type: inp = Input
lst = Output

The "v" designator is used only for the unit and source specific model runs requested by ADEQ.

APPENDIX A – ADEQ'S DRAFT BART MODELING PROTOCOL

APPENDIX B – CONTROLS COST ANALYSES

APPENDIX C – COMPLIANCE PLAN AND SCHEDULE

Domtar will implement control measures or other options for reducing emissions to comply with the proposed BART limits as expeditiously as possible and before the date five years after EPA approval of ADEQ's BART State Implementation Plan (SIP), as required by Regional Haze Rule and BART Guidelines.

Proposed BART Compliance Timeline

May 14-20, 2007	Installation of WESP on No. 1 Power Boiler complete
May 21, 2007	Tentative startup of WESP on No. 1 Power Boiler
September 13, 2007	Boiler MACT Compliance Deadline
March 11, 2008	Last day to show compliance with Boiler MACT = Date achieve BART Particulate Matter limits
Early 2010	NO_X Reduction Technology Evaluation
Late 2011	NO_X Reduction Technology Selected
Late 2012	Installation of selected NO_X Reduction Technology
Early 2013	BART Compliance Deadline

APPENDIX D – REQUESTED DESIGN DETAILS OF NO. 1 POWER BOILER

The No. 1 power boiler, built by Babcock & Wilcox in 1967, is a balanced draft, two drum sterling boiler designed to burn natural gas, fuel oil and bark for the production of steam.

The No. 1 power boiler has a maximum continuous steam rating of 275,000 lbs/hr at 850 psig and 850°F. The boiler discharges steam into the mill's 850# high pressure header system.

The No. 1 power boiler is typically a swing boiler (adjusts its fuel firing rate) to follow the 850 psig header pressure.

The fuel system consists of the three separate subsystems listed below that deliver combustible material into the boiler furnace.

- Bark System - supplies bark, wood waste, pelletized paper fuel, tire-derived fuel and municipal yard waste from the woodyard area and distributes it onto the grate for burning. Bark is the primary fuel source for No. 1 power boiler.
- Natural Gas System - supplies gas from the main mill pipeline to the boiler's six burners and ignitors. Natural gas is used to warm up the boiler during start-up and to supplement bark combustion to maintain load.
- No. 6 Fuel Oil System - prepares and supplies No. 6 fuel oil, used oil generated on site or reprocessed fuel oil to the boiler's burners. Oil serves primarily as a backup to natural gas and is not normally fired.

The combustion air system consists of the three subsystems listed below that provide the oxygen for fuel combustion.

- Air Supply & Preheat System - provides a steady supply of combustion air at the necessary flows and temperatures to ensure efficient combustion.
- Burner Air System - provides air for the combustion of natural gas and/or fuel oil at the burners.
- Bark Air System - provides air for drying and burning of bark system fuels on the grates (undergrate air), combustion of bark system fuels above the grates (overfire air) and distribution of bark system fuels onto the grates (distribution air).

The flue gas system consists of several components listed below that handle the by-products of combustion.

- Tubular Air Heater - transfers heat from the flue gas to the combustion air.

- Mechanical Dust Collector - removes environmentally harmful particulate from the flue gas prior to atmospheric discharge.

- ID Fan - removes the flue gas from the furnace at a controlled rate to maintain a balanced draft.

- Stack - discharges the flue gas to atmosphere.

- Sootblowers - clean the tube surfaces of ash and slag deposited from the flue gas.

The No. 1 Power Boiler will undergo a modification in May 2007 that will entail the installation of a Wet Electrostatic Precipitator to bring the boiler into compliance with the Boiler MACT regulation for particulate matter emissions.

ncasi

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Ronald A. Yeske, Ph.D.
President
(919) 941-6404

June 9, 2006

TO: Corporate Correspondents -- CC 06-014
Regional Managers

FROM: Ronald A. Yeske

SUBJECT: Information on Retrofit Control Measures for Kraft Pulp Mill Sources and Boilers for NO_x, SO_2 and PM Emissions

The attached document "Retrofit Control Technology Assessment for NO_x, SO_2 and PM Emissions from Kraft Pulp and Paper Mill Unit Operations" was prepared to assist NCASI member company personnel involved in conducting Best Available Retrofit Technology (BART) site-specific engineering analyses. It deals with the three main pollutants of concern for BART analyses, namely NO_x, SO_2 and particulate matter (PM). Potentially available control technologies for these three pollutants for kraft recovery furnaces, lime kilns and boilers burning wood, coal, gas, or oil are discussed. Also, control technologies for PM emissions from lime slakers and smelt dissolving tanks are briefly reviewed.

Sources subject to BART analyses were generally built in the 1962 to 1977 time frame. Thus, application of any control technologies to these sources will involve retrofits. Even though a given technology may have been installed on newer more modern units, or may be theoretically applicable, retrofitting the technology to an older existing unit requires consideration of unit-specific and location-specific factors. In many situations, these factors would eliminate one or more control technologies from consideration due to technical infeasibility or excessive costs. As noted throughout this document, site-specific factors will play a critical role in BART analyses.

This document does not directly address the cost-effectiveness ($/ton of pollutant removed) of retrofit control measures. Site-specific information, including capital costs, operating and maintenance costs, and annual capacity factors, must be considered in assessing the cost-effectiveness of a given control technology to a particular emission source. Not surprisingly, the ranges in costs and potential emission reductions are expected to be very large.

For more information on this document, please contact Dr. Arun V. Someshwar, Principal Research Engineer, at the Southern Regional Center office, phone (352) 331-1745, ext 226; email asomeshwar@ncasi.org.

Attachment

Retrofit Control Technology Assessment for NO_x, SO_2 and PM Emissions From Kraft Pulp and Paper Mill Unit Operations

by Arun V. Someshwar, Ph. D., NCASI

1.0 Introduction

This document summarizes the general applicability of currently available emission control technologies for NO_x, SO_2 and particulate matter (PM) to various pulp and paper mill sources. The three main unit operations in a kraft pulp mill that emit NO_x, SO_2 and PM are kraft recovery furnaces, lime kilns and boilers. Boilers can be of the type which burn wood residues alone, wood in combination with coal, gas or oil, or only fossil fuels. Particulate emissions can also result from lime slakers and smelt dissolving tanks. Other pulp and paper mill sources for PM are generally quite insignificant.

The origin and nature of the three pollutants in each relevant pulp mill unit operation is first discussed. Such discussion should be useful in understanding why some control technologies, while being suitable candidates for certain unit operations in other industries, may not be suitable in the pulp and paper industry. It is hoped this document will be useful in the context of a Best Available Retrofit Technology (BART) site-specific engineering analysis. However, it must be clearly noted that for any retrofit technology, site-specific considerations for a given emission source may disqualify a particular control technology from consideration, even though it might theoretically be feasible or may even have been installed elsewhere on a new, modern unit or a greenfield operation.

Cost and emission reduction estimates are specifically not covered in this document. However, it is instructive to consider that a wide range in costs and potential emission reductions are expected due to the fact that site-specific factors play a critical role in determining how cost-effective various technologies will be in practice. Many facilities are space-limited, have controls already in place, or have older combustion equipment that cannot be retrofit to reach required conditions, making installation of certain technologies problematic or very expensive.

2.0 Kraft Recovery Furnaces

2.1 NO_x Control

Compared to coal- or residual oil-fired boilers of similar capacity, NO_x emissions from kraft recovery furnaces are generally quite low, typically in the 60 to 130 ppm range. These low NO_x emissions are due to several factors inherent to kraft recovery furnace operations which include (a) low nitrogen concentrations in most "as-fired" black liquor solids (generally <0.2%), (b) recovery furnace NO_x formation resulting predominantly from "fuel NO_x" mechanisms (insufficient temperatures for "thermal NO_x" formation), (c) the highly staged combustion design of recovery furnaces, and (d) the existence of sodium fumes that might participate in "in-furnace" NO_x reduction or removal.

Researchers have concluded that nearly two-thirds to three-fourths of the liquor N is released during pyrolysis or devolatilization, partly as NH_3 and partly as N_2, the rest remaining with the smelt product most likely as a reduced N species. The ammonia released from the black liquor during pyrolysis partly oxidizes to NO and partly reduces to N_2. A review of the theoretical kinetics governing the reactions between NH_3, NO, and O_2 suggests that, in the presence of excess O_2, a decrease in temperature decreases the degree of oxidation of NH_3 to NO, thus implying that fuel NO_x generation during black liquor combustion is more temperature-dependent than previously thought. However, a reduction in furnace temperatures, particularly in the lower furnace, is generally expected to result in a sharp increase in SO_2 emissions from the furnace. Most of the NO is formed by oxidation of the NH_3 volatilized during pyrolysis of the liquor droplets. Very little NO is formed from the N in the char bed. In certain instances, where the liquor droplet dries completely before reaching the char bed, additional NO can be formed during "in-flight" char combustion of the liquor droplet. The use of liquor sprays resulting in larger droplet sizes avoids the problem of additional NO contribution from char burning.

Some have observed that NO_x emissions increased when firing liquors with increasing liquor solids contents. However, this may have had less to do with thermal NO_x or an "in-furnace" capability of alkali fume to capture NO_x as suggested by some, but more to do with a possible effect on increased conversion of ammonia to NO within the furnace due to an increase in lower furnace temperatures resulting from firing higher solids liquors.

2.1.1 Low NO_x Burners

The use of low-NO_x burners (LNB) for black liquor combustion has not been demonstrated. Unlike fossil fuels, black liquor has a large quantity of water and the drying, pyrolysis, and char burning of liquor droplets occurs over a long flight trajectory from the liquor guns to the char bed, thus making unavailable the benefits of staged combustion inherent in LNB designs.

LNBs could however be applied to oil guns or gas burners in recovery furnaces that are used to supply supplemental heat or for start-up/shut down purposes. However, for most recovery units, the use of auxiliary fuel is very limited; in such cases the benefit from conversion to LNB would be marginal.

2.1.2 Staged Combustion

Recent research has concluded that to the extent "staged combustion" is allowed to take place in the upper furnace during oxidation of the volatilized NH_3 to NO, such oxidation can be minimized. Limited short-term experience after installing "quaternary" air ports in two U.S. furnaces showed that a 20 to 40% reduction in baseline NO_x levels is feasible using such air staging. However, to make it feasible to install a quaternary air system a recovery furnace typically needs to be fairly large in size. Thus this option would not be feasible for most BART-eligible recovery furnaces, since units built in the 1962 t o 1977 time period were considerably smaller than those installed in subsequent years.

2.1.3 Flue Gas Recirculation (FGR)

Flue gas recirculation (FGR) is also not a viable option for kraft recovery furnaces. In FGR, a portion of the uncontrolled flue gases is routed back to the combustion zone, primarily with the intention of reducing thermal NO_x. Thermal NO_x is, however, not a concern in recovery furnaces, as discussed earlier. FGR would add additional gas volume in the furnace, increasing velocities and potentially causing more liquor carryover, which would result in increased fouling of the recovery furnace tubes.

2.1.4 Oxygen Trim + Water Injection

Oxygen-trim + water injection, a NO_x control technology generally utilized in natural gas-fired boilers, would not be relevant to kraft recovery furnaces since (1) any injection of water into the furnace would lead to an unacceptable explosive condition and (2) the oxygen trim technique would have marginal effect due to the already existing highly staged combustion air configuration in recovery furnaces.

2.1.5 Selective Non-Catalytic Reduction (SNCR)

At the current time, there is no published information on the extended use of SNCR on an operating kraft recovery furnace. Short-term tests with the SNCR technology have been reported in the literature on two furnaces in Japan and one in Sweden. There are a number of critical, unresolved issues surrounding the use of urea or ammonia injection in a kraft recovery furnace for NO_x control over a long-term basis. A kraft recovery furnace is the most expensive unit operation in a pulp mill since its primary purpose is to recover chemicals from spent pulping liquors in a safe and reliable manner. Although steam is generated from liquor combustion, certain chemical recovery steps have to be accomplished inside the furnace. It is not known whether the injection of NO_x-reducing chemicals into the furnace would have deleterious effects on the kraft liquor recovery cycle on a long-term basis. Long-term tests would need to be carried out to address this important issue. In addition, there are several other factors that make the use of SNCR in a kraft recovery furnace problematic such as (1) the impact of large variations in flue gas temperatures at the superheater entrance due to fluctuating load and liquor quality, (2) limited residence times for the NO_x-NH_3 reactions available in smaller furnaces, (3) impact on fireside deposit buildup due to reduced chloride purging from long-term NH_3/urea use and resulting impact on tube corrosion and fouling, and (4) potential for significant NH_3 slip and plume opacity problems due to NH_4Cl emissions. Unless these concerns are satisfactorily resolved, the use of SNCR in a kraft recovery furnace should not be considered as a feasible technology.

2.1.6 Selective Catalytic Reduction (SCR)

The use of SCR on a kraft recovery furnace has never been demonstrated, even on a short-term basis. The impact of high particulate matter concentrations in the economizer region and fine dust particles on catalyst effectiveness is a major impediment to the application of this technology ahead of PM control, as is catalyst poisoning by soluble alkali metals in the gas stream. For SCR installation after an ESP, the gas stream would be too cold for effective reaction with the NO_x. A substantial energy penalty would have to be incurred to reheat the flue gas prior to the SCR section which would be a major drawback.

2.1.7 Summary

In summary, optimization of the staged combustion principle within large, existing kraft recovery furnaces to achieve lower NO_x emissions might be the only technologically feasible option at the present time for NO_x reduction. However, the effect of such air staging on emissions of other pollutants, chiefly SO_2, CO, and TRS, and other furnace operational characteristics needs to be examined with longer-term data on U.S. furnaces. Ultimately, the liquor nitrogen content, which is dependent on the types of wood pulped, is the dominant factor affecting the level of NO_x emissions from black liquor combustion in a recovery furnace. Unfortunately, this factor is beyond the control of pulp mill operators.

2.2 SO_2 Control

Black liquor contains a significant amount of sulfur, nominally 3 to 5% by weight of the dissolved solids. While the vast majority of this sulfur leaves the furnace in the smelt product, a small fraction (generally under 1%) can escape in gaseous or particulate form. Average SO_2 concentrations in stack gases can range from nearly 0 to 500 ppm, although most furnaces currently operate with <100 ppm SO_2 in stack emissions. Factors which influence SO_2 levels are liquor sulfidity, liquor solids content, stack oxygen content, furnace load, auxiliary fuel use, and furnace design. However, none of these factors has exhibited a consistent relationship with SO_2 emissions. At the present time, it is generally understood that conditions involving liquor quality (such as high Btu, high solids liquors) and liquor firing patterns and conditions related to furnace operations (air distribution, auxiliary fuel, etc.) that lead to maximizing temperatures in the lower furnace result in minimizing SO_2 emissions from kraft recovery furnaces.

There is no experience in the pulp and paper industry with the use of dedicated, add-on flue gas desulfurization technologies on kraft recovery furnaces. Although there are a few scrubbers on U.S. kraft recovery furnaces, none of these were installed for SO_2 removal. Only one U.S. recovery furnace does not use an ESP for particulate control; this unit has venturi scrubbers instead. All of the other scrubbers follow an ESP. Two were installed for heat recovery reasons, although some SO_2 scrubbing may also be occurring especially when caustic is added to the scrubbing solution. One scrubber following an ESP was installed with the main purpose of achieving incremental particulate matter removal. Another scrubber following an ESP was installed on a furnace with a direct contact evaporator to control black liquor droplets being entrained in the cascade and traveling all the way throughout the ESP and out the stack. Even if these scrubbers had been installed to reduce SO_2 emissions, the removal costs in terms of dollars per ton of SO_2 removed would be large due to high gas flows and site-specific retrofit considerations. Significant capital would be required for the large gas handling equipment and additional induced fan capacity needed to overcome the increased pressure drop across the scrubber.

2.3 Particulate Matter Control

Recovery furnaces are designed and operated in a manner so as to ensure the presence of high levels of sodium fumes in order to capture the sulfur dioxide produced as a result of oxidation of reduced sulfur compounds. Consequently, uncontrolled recovery furnace flue gases contain high levels of particulate matter. The uncontrolled particulate matter load from recovery furnaces is highly variable and has been reported to range from 100 to 250 lb/ODTP (oven dry ton pulp) for direct contact evaporator (DCE) furnaces and 200 to 450 lb/ODTP for non-direct contact evaporator (NDCE) furnaces. The lower particulate loading from DCE furnaces is due to the capture of some particulate matter in the direct contact evaporator. ESPs built for NDCE furnaces are designed to compensate for the higher particulate loading.

Particulates generated in the recovery furnace are comprised mainly of sodium sulfate, with lesser amounts of sodium carbonate and sodium chloride. Similar potassium compounds are also generated, but in much lower amounts. Trace amounts of other metal compounds, e.g. magnesium, calcium, and zinc, can be present. A significant portion of the particulate material is sub-micron in size, which makes removal with additional add-on control devices more difficult.

Increasing liquor firing density (ton/day/ft^2) increases recovery furnace particulate loading. Other factors such as bed and furnace temperature, liquor solids, liquor composition, and air distribution also affect uncontrolled particulate emissions from recovery furnaces.

ESPs are the device of choice for controlling PM emissions from kraft recovery furnaces. The use of larger ESPs is expected to result in better overall PM capture efficiencies. However, this option is expected to be quite cost ineffective based on the high, site-specific, retrofit costs incurred. Moreover, with the implementation of MACT II limitations in 2004, most recovery furnaces are operating at or below NSPS levels (NCASI Corporate Correspondents Memo 01-01). Any additional benefit would thus be marginal.

3.0 Kraft Lime Kilns

3.1 NO_x Control

NO_x emissions from lime kilns result mainly from fossil fuel burning (natural gas and fuel oil). A recent NCASI study involving NO_x testing at 15 lime kilns verified that “thermal” NO_x was the sole mechanism operative in gas-fired kilns, while the “fuel” NO_x mechanism was mostly operative in oil-fired kilns. Gas-fired kiln NO_x emissions appeared to be strongly dependent on the dry-end lime temperature. Oxygen availability in the combustion zone was determined to be the key factor in oil-fired kilns. NO_x emissions for gas-fired kilns also exhibited high short-term variability, unlike for oil-fired kilns. Analysis of long-term daily average data from two lime kilns showed no difference in NO_x emissions between days with and without LVHC NCG burning. An earlier NCASI study had shown that when stripper off-gases (SOGs) containing ammonia were burned in lime kilns, a small fraction of the ammonia, up to 23%, converts to NO_x.

A BACT analysis conducted for a new lime kiln in 1997 concluded that the use of low NO_x burners in lime kilns was technically infeasible due to complexities resulting in poor efficiency, increased energy usage, and decreased calcining capacity of the lime kiln. The concept of 'low NO_x burners' is considered a misnomer in the rotary kiln industry. In boiler burners where the combustion air can be staged, 'low NO_x' could be a genuine option. However, in rotary kilns it is not possible to stage the mixing in the same way. There has to be sufficient primary (burner) air to provide control in flame shaping although this can be limited to minimize NO_x to some extent. Effectively, the NO_x can be reduced to some extent by 'de-tuning' the burner from optimized combustion. However, the result is an energy penalty by way of a higher heat input per ton product and higher feed-end temperatures.

Post-combustion flue gas NO_x control using SCNR or SCR is not feasible due to the configuration of the kraft lime kiln. The necessary temperature window of 1500°F to 2000°F for reagent injection in the SNCR process is unavailable in a kraft lime kiln. The very high PM load prior to control would make SCR infeasible in advance of the controls and the requisite temperature window of between 550°F and 750°F for applying SCR after a PM control device is unavailable for a lime kiln, even for one equipped with an ESP.

Thus, NO_x control in newer lime kilns may be achieved mainly by minimizing the hot end temperatures in gas-fired kilns and by reducing the available oxygen in the combustion zone in oil-fired kilns, both combustion related modifications. However, these modifications may be difficult to achieve in certain existing kilns due to their inherent design. For example, in order to complete the calcining reactions in kilns with short residence times, it is more difficult to control hot end temperatures in shorter kilns than in longer ones.

3.2 SO_2 Control

Sulfur dioxide is formed in lime kilns when fuel oil or petroleum coke is burned as primary fuel. SO_2 will also be formed if non-condensible gases (NCGs) or stripper off-gases (SOGs) containing sulfur are burned in the kiln. Lime muds also contain a small amount of sulfur, which when oxidized, would form SO_2. Median sulfur content of concentrated NCGs and SOGs have been reported as 1.1 and 4.2 lb/ADTP (air dried ton pulp), respectively. Median sulfur contents of 7 lime muds have been reported at 0.2%, which translates to about 1.8 lb S/ADTP. Thus, fossil fuels such as fuel oil, kraft mill NCG/SOGs, and soluble sulfides in lime mud can contribute a significant amount of sulfur to the inputs of a lime kiln. Nevertheless, the regenerated quicklime in the kiln acts as an excellent in-situ scrubbing agent, and venturi scrubbers following the kiln can further augment this SO_2 removal process since the scrubbing solution becomes alkaline from the captured lime dust. Consequently, even though the potential for SO_2 formation in a kiln that burns sulfur-containing fuels with or without NCGs/SOGs is high, most lime kilns emit very low levels of SO_2 (~50 ppm). Some kilns do, however, occasionally emit higher levels of SO_2 (50 to 200 ppm). Not much is known about why this happens.

Emission test data show that SO_2 concentrations do not appear to be related to either the fuel type (oil, gas) or the presence or absence of concentrated NCG or SOG burning in the kiln. A preliminary sulfur input-output balance carried out on 25 kilns with wet scrubbers and 7 kilns with electrostatic precipitators (ESPs), with sulfur inputs from fuel oil, NCGs and SOGs, or just lime mud, showed over 95% of the SO_2 generated from the oil, NCG/SOGs, or lime mud was captured within the kiln. For kilns with wet scrubbers (majority) that have high SO_2 emissions, alkali addition to the scrubbing fluid could further reduce the SO_2 emissions.

3.3 Particulate Matter Control

While passing through the kiln, the combustion gases pick up a good deal of particulate matter both from lime mud dust formation and from alkali vaporization. This PM must be removed before the gases exit to the atmosphere. Mechanical devices such as dust chambers or cyclones are generally used to remove larger particles, which are mainly calcium-containing. A wet scrubber or electrostatic precipitator follows for removal of smaller particulates, which are mainly sodium sulfate and sodium carbonate and have aerodynamic diameters less than 10 µm.

Kraft lime kiln PM emissions are typically controlled by venturi-type wet scrubbers. Scrubbers with increasingly better PM removal efficiencies, such as the Ducon Dynamic Wet Scrubber, have been installed up until the late 1980s. However, most of the PM control installations on lime kilns since about 1990 have been ESPs. Replacing a wet scrubber with an ESP will most likely reduce PM emissions, but may increase emissions of SO_2. The wet scrubber acts as an additional alkaline SO_2 scrubber since it captures alkaline PM leaving the kiln. Just as for recovery furnaces, with the implementation of MACT II limitations in 2004, most lime kilns are operating at or below NSPS levels. Any additional benefit would thus be marginal.

4.0 Boilers

The majority of pulp and paper industry boilers are combination boilers, in that they are designed to burn more than one fuel. Thus, it should be noted that while a particular technology may be beneficial for a particular pollutant, the same technology may not address the control of another pollutant. For example, a wood-fired boiler with a wet scrubber for PM control may obtain better PM control with an ESP. However, if the boiler also fires some sulfur-containing fuel (as is often the case), the SO2 removal capability of the wet scrubber will be sacrificed by the installation of an ESP.

4.1 Natural Gas-Fired Boilers

Gas-fired boilers are usually not equipped with particulate collectors. SO_2 emissions depend on the sulfur content of the gas, which is typically negligible. NO_x emissions are dependent on the combustion temperature and the rate of cooling of the combustion products. There are several combustion modification techniques available to reduce the amount of NO_x formed in natural gas-fired boilers and turbines. The two most prevalent ones are flue gas recirculation (FGR) and low-NO_x burners. FGR reduces formation of thermal NO_x by reducing peak temperatures and limiting availability of oxygen. Low-NO_x burners reduce formation of thermal NO_x by delayed combustion (staging) resulting in a cooler flame. In conjunction with FGR, the burners can achieve NO_x emission reductions of 60 to 90%. Other techniques include staged combustion and gas reburning. In general, these techniques have been incorporated in newer boilers and thus their NO_x emissions are lower than those of older units.

There are also add-on control technologies that can reduce NO_x emissions from gas-fired boilers such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). However, since most of the pulp and paper industry gas-fired boilers are of the package boiler type, cost considerations typically make the use of such technologies cost ineffective. Further, both the SNCR and SCR technologies have not been proven to apply to industrial boilers with frequent swing loads.

4.2 Fuel Oil-Fired Boilers

For fuel oil-fired boilers, criteria pollutants can be controlled by fuel substitution/alteration, combustion modification and post-combustion control. Fuel substitution reduces SO_2 and NO_x and involves burning an oil with lower S or N content, respectively. Particulate emissions are lower when burning lower sulfur content oils, especially distillate oil.

4.2.1 NO_x Control

For boilers burning residual oil, fuel NO_x is the dominant mechanism for NO_x formation and thus the most common combustion modification technique is to suppress combustion air levels below the theoretical amount required for complete combustion. There are several combustion modification techniques available to reduce the amount of NO_x formed in fuel oil-fired boilers, including low excess air, burners out of service, biased-burner firing, flue gas recirculation, overfire air, and low-NO_x burners. NO_x reductions that could range between 5 and 60% from uncontrolled systems may be expected from using these techniques.

Post-combustion controls include SNCR and SCR. NO_x reductions from 25 to 0% and from 75 to 85% may be expected from use of SNCR and SCR systems on oil-fired boilers, respectively. However, just as for gas-fired boilers, most of the pulp and paper industry oil-fired boilers are of the package boiler type, and cost considerations typically make the use of such technologies cost ineffective. Furthermore, both the SNCR and SCR technologies have not been proven to apply to industrial boilers with frequent swing loads.

4.2.2 SO_2 Control

SO_2 emissions are controlled by a number of commercialized post-combustion flue gas desulfurization (FGD) processes which use an alkaline reagent to absorb SO_2 in the flue gas and produce a sodium or calcium sulfate compound. The FGD technologies may be wet, semi-dry or dry depending on the state of the reagent as it leaves the absorber vessel.

4.2.3 Particulate Matter Control

Due to the extremely low level of PM emissions, most residual oil-fired boilers do not have particulate matter controls. A few boilers are, however, equipped with mechanical collectors or ESPs.

4.3 Coal-Fired Boilers

4.3.1 NO_x Control

NO_x emissions from coal-fired boilers can be controlled by a) combustion controls and b) post-combustion controls. Combustion controls involve a) reducing peak temperatures in the combustion zone, b) reducing gas residence time in the high-temperature zone, and c) air or fuel staging by operating at an off-stoichiometric ratio by using a rich fuel-air ratio in the primary flame zone and lower overall excess air conditions. The use of combustion controls depends on the type of boiler and the method of coal firing. Low-NO_x burners and overfire air (OFA) have been successfully applied to tangential- and wall-fired units, whereas reburning is the only current option for cyclone boilers. For large base-loaded coal-fired boilers, the most developed and widely applied post-combustion NO_x control technology is SCR. Catalyst deactivation and residual NH_3 slip are the two key operating considerations in an SCR system. There is only limited experience with the use of SNCR systems on industrial coal-fired boilers. NO_x reductions from 30-70% and from 60-90% may be expected from use of SNCR and SCR systems on base-loaded coal-fired boilers, respectively. SNCR has a narrow temperature window in which it is effective, in the 1500 to 1900°F range, and SCR has a similar, but lower temperature window of 550 to 750°F. When applied to industrial boilers, neither the SNCR nor the SCR technologies have been proven to yield the same high NO_x removal efficiencies expected when the boilers operate at base loads as when they operate with frequent swing loads. The inability to maintain good control within the required temperature window during swing loads is most likely responsible for this reduction. Most coal-fired boilers in the pulp and paper industry operate in the swing load mode, a function of supplying steam as required to the various components of the process.

4.3.2 SO_2 Control

Just as in fuel oil combustion, criteria pollutants can be controlled by fuel substitution/alteration, combustion modification and post-combustion control. SO_2 reductions can be achieved by burning a coal with lower S content. SO_2 emissions can be controlled by a number of commercialized post-combustion flue gas desulfurization (FGD) processes which use an alkaline reagent to absorb SO_2 in the flue gas and produce a sodium or calcium sulfate compound. The FGD technologies may be wet, semi-dry or dry depending on the state of the reagent as it leaves the absorber vessel. The pulp and paper industry has limited experience with operating FGD systems on coal- or oil-fired boilers. Retrofit considerations include space restraints in many facilities.

4.3.3 Particulate Matter Control

Particulate emissions from coal-fired boilers are controlled by using a) ESPs, b) fabric filters (FF) or c) venturi scrubbers. Multi-cyclones are generally used as precleaners upstream of more efficient ESPs or FFs. The key operating parameters that influence ESP performance include fly ash mass loading, particle size distribution, fly ash resistivity (which is related to coal sulfur content), and precipitator voltage and current. Data for ESPs applied to coal-fired boilers show fractional collection efficiencies greater than 99% for fine (<0.1μm) and coarse particles (>10 μm) and a reduction in collection efficiency for particles between 0.1 and 10 μm. Operational parameters that affect fabric filter collection efficiency include air-to-cloth ratio, operating pressure loss, cleaning sequence, interval between cleanings, cleaning method, and cleaning intensity. Collection efficiencies of fabric filters can be as high as 99.9%. Scrubber collection efficiency depends on particle size distribution, gas side pressure drop through the scrubber, and water (or scrubbing liquor) pressure, and can range from 90 to 95% for a 2 μm particle.

4.4 Wood-Fired Boiler Emissions

4.4.1 NO_x Control

Most large wood-fired boilers used in the pulp and paper industry are of the spreader stoker design. NO_x control technologies effective for use on gas and oil burners are not applicable to spreader-stoker design boilers. Furthermore, these boilers are often operated handling swing loads, which makes add-on NO_x controls difficult to implement. Spreader stoker boilers inherently practice staged combustion, which lowers NO_x emissions, but within limits.

Fuel NO_x is the dominant NO_x formation mechanism operative during wood combustion. Fuel NO_x is most efficiently controlled by staged combustion. Overfire air ports inherent to most spreader-stoker boilers provide for staged combustion. The underfire and overfire air are balanced in most wood-fired spreader stokers to control NO_x.

As with other fuels, potential post-combustion controls include SNCR and SCR. SNCR has been applied to a few base-loaded wood-fired boilers, mainly in the electric generating industry. However, its long-term efficacy on wood-fired boilers with changing loads has not been demonstrated. Experience in the pulp and paper industry to date has shown it has been used on occasions for polishing, to get perhaps 10-20% NO_x reduction during periods of air quality problems. The problem with control of the required temperature window is an inherent difficulty with use of SNCR for load-following boilers, whether wood or fossil fuel. Inadequate reagent dispersion in the region of reagent injection in wood-fired boilers is also a factor mitigating against the use of SNCR technology. At least one pulp mill wood-fired boiler met with significant problems and had to abandon their SNCR system. Significant ammonia slip, caused by inefficient dispersion of the reagent within the boiler, was to blame.

The use of SCR on wood-fired boilers operating in the forest products industry has also never been successfully demonstrated for spreader stoker boilers, and would face the same inherent problem of requiring it to be post PM-control to protect the catalyst, and achieving and maintaining the required temperature window for effective NO_x control.

4.4.2 Particulate Matter Control

Particulate matter is the air pollutant of primary concern in wood-fired boilers. As for coal-fired boilers, the most common devices used to control particulate emissions from wood-fired boilers are wet scrubbers and electrostatic precipitators (ESPs). Fabric filters (FF) and the electrified gravel bed filter (EGF) have been used on a few units. Wet scrubbers are widely used, operating at gas pressure drops ranging from 6 to 25” H_2O. Liquid to gas ratios in the venturi system typically range from 8 to 10 gal H_2O/1000 acfm saturated. Solids buildup in the recirculation loop rarely is allowed to exceed 5% by weight. High carbon ash resulting from wood combustion is more difficult to remove with an ESP due to its high conductivity/low resistivity. Thus, specific collection areas (ratio of ESP plate area to gas flow volume through the ESP) for ESPs on wood-fired boilers are greater than for those for coal-fired boilers, ranging from about 300 to 500 ft^2/1000 acfm. Power requirements range from 150 to about 400 watts per acfm. To address fire concerns, ESPs on wood-fired boilers are sometimes operated in the wet mode, where the collection plates and internal parts are wetted continuously with water. A pre-quench is generally used to saturate the gas stream. Fabric filters are rarely used on wood-fired boilers due to concerns about bag flammability. Fabric filters have been successfully used where bark from logs stored in salt water is burned and the salt reduces the fire hazard. In this situation, the fabric filter is effective in removing the very small salt particulates exiting the boiler. Gravel-bed filters have a slowly moving bed of granular "rock" as the filtration medium through which the flue gas must travel. These systems are electrostatically augmented (10 to 20 watts/1000 acfm). A high voltage (about 50 kV) is applied to an electrical conductor positioned within the bed and this creates an electrical field between the conductor and the inlet and outlet louvers. Particulate collection efficiencies for wood-fired boilers range from 65 to 95% for two multiclones in series, over 90% for wet scrubbers, from 93 to 99.8% for ESPs and FFs and about 95% for EGFs. Once again, it should be noted that most wood-fired boilers are combination boilers that may burn other sulfur-containing fuels. Thus, a change in the control device might affect the ability to control other pollutants. For example, replacing a wet scrubber with an ESP for better PM control would result in higher SO_2 emissions from a boiler burning wood in combination with oil or coal.

5.0 Other Source Emissions

5.1 Slakers - PM emissions

Slakers are generally vented through a stack to discharge the large amounts of steam generated. The steam may contain particulate matter, which is largely calcium and sodium carbonates and sulfates. Scrubbers are generally employed to capture this particulate matter. Other PM control devices such as ESPs and fabric filters are both technologically infeasible (very high moisture source) and not cost effective.

5.2 Smelt Dissolving Tanks - PM Emissions

As with the recovery furnace, particulate emissions from smelt tanks are comprised of mainly sodium compounds with much lesser amounts of potassium compounds and some other trace metal compounds. The dominant compound is sodium carbonate, followed by sodium sulfate. Roughly 90% (by weight) of the particles have equivalent aerodynamic diameters under 10 µm, and 50% have diameters under 1 µm. Most smelt tank PM emissions are controlled by wet scrubbers, many of which are wetted fan scrubbers that are very effective in removing fine particulate. A dry ESP is once again infeasible as an option due to the high moisture content of the gases. The wet scrubber also serves to control total reduced sulfur compound emissions through pH control, thus replacing it with a wet ESP is not an option. As noted for other kraft mill sources, MACT II Implementation in 2004 has also resulted in significantly reduced allowable PM emissions from smelt dissolving tanks.

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NATIONAL COUNCIL FOR AIR AND STREAM IMPROVEMENT

NO_X CONTROL IN FOREST PRODUCTS INDUSTRY BOILERS: A REVIEW OF TECHNOLOGIES, COSTS, AND INDUSTRY EXPERIENCE

SPECIAL REPORT NO. 03-04
AUGUST 2003

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PRESIDENT'S NOTE

The United States Environmental Protection Agency and many state agencies are attempting to lower ambient ozone concentrations by reducing emissions of precursor compounds, including NO_x. The contribution of NO_x to secondary fine particulate matter and regional haze is actively being studied by EPA as it develops strategies to reduce ambient $PM_{2.5}$ levels. As a result of these regulatory initiatives, it is not surprising to find an escalating interest in the investigation of NO_x emissions and options for reduction. Although forest products manufacturing facilities represent only about 1% of the total U.S. NO_x emissions, many regulatory agencies have been scrutinizing mill NO_x emission sources for potential reductions.

Therefore, NCASI has devoted considerable efforts in recent years to studying NO_x emissions from mill combustion sources, including kraft recovery furnaces, lime kilns, thermal oxidizers, and power boilers, particularly those burning wood residues. At most mills, boilers are the largest NO_x emission source and are thus the most frequent target for reductions. To assist mills in responding to regulatory agency pressures for NO_x reductions, NCASI issued a special report in 1999 (*A Review of* NO_x *Emission Control Strategies for Industrial Boilers, Kraft Recovery Furnaces, and Lime Kilns)*. Since there have been significant developments over the past five years in combustion modifications and add-on control technologies for boiler NO_x reductions, NCASI reviewed the more recent information to update the 1999 report.

This special report is meant to serve as a background document to assist member companies in responding to NO_x limitations that might be proposed by regulatory agencies as a result of uniform State Implementation Plan (SIP) requirements for industrial boilers or in permitting decisions for individual units. It reviews NO_x control technologies that are available for direct application to forest products industry boilers, or that may be transferable from current utility boiler applications. Limitations identified by vendors and boiler operators that could preclude successful installation and operation of certain control technologies on particular boilers have been reviewed and summarized, especially with respect to technical feasibility. NO_x control costs and removal cost-effectiveness estimates from a number of sources are provided.

NCASI appreciates the engineering, cost, and other information on boiler NO_x reductions anonymously shared by several member companies for use in this report.

Ronald A. Yeske

August 2003

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MOT DU PRESIDENT

L'EPA et plusieurs agences d'état tentent de diminuer les concentrations d'ozone dans l'air ambiant par la réduction des émissions de composés précurseurs, tels que les NO_x. La contribution des NO_x aux particules secondaires et à la brume sèche en régions (*regional haze*) est actuellement à l'étude par l'EPA. L'EPA est en cours de développement de stratégies pour réduire les niveaux ambiants de $PM_{2.5}$. Il n'est pas surprenant de voir apparaître, suite à ces initiatives réglementaires, un intérêt grandissant pour la recherche sur les émissions de NO_x de même que sur les options de réduction de ces polluants. Malgré le fait que l'industrie des produits forestiers ne représente qu'environ 1% des émissions totales de NO_x aux États-Unis, plusieurs agences de réglementation se sont penchées sur les sources d'émissions de NO_x des fabriques afin de déceler des réductions potentielles.

Par conséquent, NCASI a déployé des efforts considérables depuis les dernières années afin d'étudier les émissions de NO_x des sources de combustion des fabriques, incluant les fournaises de récupération kraft, les fours à chaux, les oxydateurs thermiques et les chaudières, plus particulièrement celles qui sont alimentées par de la biomasse. Dans la plupart des fabriques, les chaudières demeurent les principales sources d'émissions de NO_x et elles représentent une cible de choix pour ce qui est des réductions potentielles. Afin de soutenir les fabriques qui doivent répondre aux pressions des agences de réglementation pour ce qui est des réductions d'émissions de NO_x, NCASI a publié un rapport spécial en 1999 (*Une revue des stratégies de contrôle des émissions de* NO_x *pour les chaudières, les fournaises de récupération kraft ainsi que les fours à chaux)*. Depuis les cinq dernières années, d'importants développements ont vu le jour en matière de modifications de la combustion et de technologies de contrôle pour la réduction des émissions de NO_x des chaudières. NCASI a brossé un tableau des informations les plus récentes afin de mettre à jour son rapport de 1999.

Ce rapport spécial se veut un document de référence afin d'aider les compagnies membres à répondre aux exigences de réductions des émissions de NO_x qui peuvent être proposées par les agences de réglementation dans le cadre du Plan d'implantation de l'état (*State Implementation Plan*) pour les chaudières ou encore suite aux décisions reliées aux autorisations et permis pour les unités individuelles. Le rapport fait la revue des technologies de contrôle des NO_x qui sont disponibles pour une application directe dans les chaudières de l'industrie forestière ou encore qui peuvent être transférées des expériences acquises sur les chaudières de centrales thermiques. Les limites identifiées par les fournisseurs et les opérateurs de chaudières et qui sont susceptibles de nuire au succès de l'installation et de l'opération de certaines technologies de contrôle des NO_x sur des chaudières spécifiques ont fait l'objet d'une revue et d'une synthèse, principalement en ce qui concerne la faisabilité technique. On trouve également dans ce rapport les coûts de contrôle des NO_x et les estimés d'efficacité d'enlèvement pour plusieurs sources.

NCASI tient à remercier les nombreuses compagnies membres qui ont bien voulu partager, dans l'anonymat, des données sur les travaux d'ingénierie, les coûts et d'autres informations en matière de réduction des NO_x émis par les chaudières. Ces données ont été utilisées dans ce rapport.

Ronald A. Yeske

Août 2003

NO_X CONTROL IN FOREST PRODUCTS INDUSTRY BOILERS: A REVIEW OF TECHNOLOGIES, COSTS AND INDUSTRY EXPERIENCE

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ABSTRACT

Recent information on techniques for reducing NO_x emissions from boilers burning fossil fuels and biomass fuels is reviewed. The applicability of both combustion modifications and flue gas treatment to industrial-sized boilers at forest products manufacturing facilities is discussed. Difficulties inherent in applying various technologies to boilers burning coal, gas, oil, wood, or combinations thereof are highlighted. Combustion modifications such as the use of low-NO_x burners and overfire air appear suitable for most coal, oil and gas-fired boilers, although cost considerations in each individual instance should be evaluated. Selective non-catalytic reduction (SNCR) by urea injection appears to be a viable NO_x reduction technology for base-loaded boilers. However, its applicability to boilers with swinging loads needs further research and development. Problems with ammonia slip and curtailed NO_x removal efficiencies are key concerns. Installation and operation of selective catalytic reduction (SCR) on industrial boilers firing coal, oil, and gas is the most expensive add-on control option. There are numerous issues with using SCR on wood and combination wood-fired boilers, including catalyst plugging and soluble alkali poisoning as well as increased energy consumption. Emerging technologies such as gas reburning and low temperature oxidation followed by scrubbing, hold much promise as technologies that can fill the gap in NO_x control efficiencies between the 30 to 50% expected from SNCR and 80 to 90% expected from the more expensive SCR. With regard to NO_x removal costs, available mill-generated estimates of cost-effectiveness fall in the \$2,000 to \$6,000 per ton removed range. These estimates exceed EPA's benchmark figure of \$2,000 per ton removed, a figure EPA believes is a reasonable cost for retrofit industrial boiler NO_x controls in ozone nonattainment areas.

KEYWORDS

biomass, combustion modification, cost-effectiveness, costs, fuel NO_x, LNB, OFA, SCR, SNCR, thermal NO_x, staged combustion, wood residue

RELATED NCASI PUBLICATIONS

Technical Bulletin No. 802 (March 2000). *Effect of stripper off-gas burning on* NO_x *emissions.*

Special Report No. 99-01 (April 1999). *A review of* NO_x *emission control strategies for industrial boilers, kraft recovery furnaces, and lime kilns.*

Technical Bulletin No. 646 (February 1993). *Emission factors for* NO_x, SO_2 *and volatile organic compounds for boilers, kraft pulp mills, and bleach plants.*

Technical Bulletin No. 636 (July 1992). *An analysis of kraft recovery furnace* NO_x *emissions and related parameters.*

Technical Bulletin No. 455 (April 1985). *Volatile organic carbon emissions from wood residue fired power boilers in the Southeast.*

Atmospheric Quality Improvement Technical Bulletin No. 111 (January 1981). *A study of nitrogen oxides emissions from large kraft recovery furnaces.*

Atmospheric Quality Improvement Technical Bulletin No. 109 (September 1980). *A study of wood-residue fired power boiler total gaseous non-methane organic emissions in the Pacific Northwest.*

Atmospheric Quality Improvement Technical Bulletin No. 107 (April 1980). *A study of nitrogen oxides emissions from lime kilns.*

Atmospheric Quality Improvement Technical Bulletin No. 105 (December 1979). *A study of nitrogen oxides emissions from kraft recovery furnaces.*

CONTROLE DES NO_X EMIS PAR LES CHAUDIERES DE L'INDUSTRIE DES PRODUITS DU BOIS - UNE REVUE DES TECHNOLOGIES, DES COUTS ET DE L'EXPERIENCE DE L'INDUSTRIE

RAPPORT SPECIAL NO. 03-04
AOUT 2003

RESUME

Les informations récentes portant sur les techniques de réduction des émissions de NO_x générées par la combustion de combustibles fossiles et de biomasse dans les chaudières font l'objet d'une revue. On discute des modifications de combustion et du traitement des gaz de combustion appliqué aux chaudières utilisées dans les fabriques de l'industrie des produits du bois. On trouve également des informations sur les difficultés inhérentes à l'application de différentes technologies de contrôle sur des chaudières utilisant du charbon, du gaz, de l'huile, de la biomasse ou une combinaison de ces combustibles. Les modifications de combustion telles que l'utilisation de brûleurs à bas niveau de NO_x (*low-NO_x*) et l'optimisation de l'air de combustion secondaire et tertiaire (*overfire air*) semblent applicable pour la plupart des chaudières utilisant du charbon, de l'huile et du gaz, mais les considérations économiques doivent être évaluées au cas par cas. La réduction sélective non-catalytique (SNCR) à l'aide d'injection d'urée semble être une technologie de réduction des NO_x viable pour les chaudières alimentées par la base; toutefois on se doit de poursuivre les efforts de recherche et développement en ce qui concerne l'application de cette technologie sur des chaudières dont les charges varient. Les problèmes reliés aux pertes d'ammoniac et à la diminution de l'efficacité d'enlèvement de NO_x qui en découle demeurent des préoccupations majeures. L'installation et l'opération de la réduction catalytique sélective (SCR) sur des chaudières utilisant du charbon, de l'huile et du gaz représente l'option de contrôle la plus coûteuse. Il existe plusieurs enjeux associés à l'utilisation de la SCR dans les chaudières à biomasse et les chaudières à biomasse/combustibles multiples : obstruction du catalyseur, empoisonnement par des alcali solubles et augmentation de la consommation d'énergie. On mise beaucoup sur les nouvelles technologies telles que la combustion répétée des gaz et l'oxydation à basse température suivie de l'épuration pour combler l'écart existant en ce qui concerne l'efficacité de contrôle des NO_x, entre 30 à 50% pour la SNCR et entre 80 à 90% pour la SCR, plus coûteuse. En ce qui concerne les coûts d'enlèvement des NO_x, les estimés de rentabilité obtenus dans les fabriques varient de 2 000 $ à 6 000 $ par tonne enlevée. Ces estimés dépassent l'évaluation de référence de l'EPA de 2 000 $ par tonne enlevée. L'EPA estime que ce montant représente un coût raisonnable pour modifier ou ajouter le contrôle des NO_x émis par des unités situées dans les zones de non atteinte de la norme sur l'ozone.

MOTS CLÉS

NO_x combustible, NO_x thermique, biomasse, combustion étagée, résidus de bois, SCR, SNCR, modification de combustion, NO_x bas niveau, LNB, OFA, coûts, rentabilité

AUTRES PUBLICATIONS DE NCASI DANS CE DOMAINE

Bulletin technique no. 802 (mars 2000). *Effect of stripper off-gas burning on NO_x emissions.*

Rapport spécial no. 99-01 (avril 1999). *A review of NO_x emission control strategies for industrial boilers, kraft recovery furnaces, and lime kilns.*

Bulletin technique no. 646 (février 1993). *Emission factors for* NO_x, SO_2 *and volatile organic compounds for boilers, kraft pulp mills, and bleach plants.*

Bulletin technique no. 636 (juillet 1992). *An analysis of kraft recovery furnace* NO_x *emissions and related parameters.*

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Bulletin technique sur l'amélioration de la qualité de l'atmosphère no. 111 (janvier 1981). *A study of nitrogen oxides emissions from large kraft recovery furnaces.*

Bulletin technique sur l'amélioration de la qualité de l'atmosphère no. 109 (septembre 1980). *A study of wood-residue fired power boiler total gaseous non-methane organic emissions in the Pacific Northwest.*

Bulletin technique sur l'amélioration de la qualité de l'atmosphère no. 107 (avril 1980). *A study of nitrogen oxides emissions from lime kilns.*

Bulletin technique sur l'amélioration de la qualité de l'atmosphère no. 105 (décembre 1979). *A study of nitrogen oxides emissions from kraft recovery furnaces.*

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NO_X CONTROL IN FOREST PRODUCTS INDUSTRY BOILERS: A REVIEW OF TECHNOLOGIES, COSTS, AND INDUSTRY EXPERIENCE

1.0 INTRODUCTION

As part of its strategy to reduce ground-level ozone concentrations, USEPA has become more focused on NO_x emission reductions, especially in the eastern Unites States. In 1998, EPA issued the NO_x SIP Call Rule. This rule, *NO_x Trading Program for State Implementation Plans* (40 CFR Part 96), required 22 eastern states and the District of Columbia to submit State Implementation Plan (SIP) revisions to reduce emissions of NO_x, one of the key precursors in the formation of ground-level ozone. Each of these states was assigned an NO_x budget for the summer ozone season (May 1 through September 30). The statewide budget amounts were determined by photochemical modeling. NO_x reductions could come from any type of NO_x-emitting sources, but EPA felt the most cost-effective reductions would come from utility and large industrial boilers burning coal and residual oil. However, states could target additional sources such as smaller boilers, mobile sources, and industrial processes for NO_x reductions.

States initially subject to the NO_x reduction requirements were Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia and Wisconsin. For each of these states, EPA set a target reduction total amount of NO_x (in tons) which would have to be achieved by May 31, 2004. NO_x emission reductions are based on the May 1 through September 30 ozone season. In 2002, Wisconsin was removed from the list of states subject to the SIP Call, and the first compliance period for Georgia and Missouri was moved to May 1, 2005. Southern portions of Georgia and Alabama, northern portions of Michigan and western portions of Missouri were also excluded from geographic coverage of the NO_x SIP call.

Emission reductions required by the states (except Georgia and Missouri) must be implemented by May 31, 2004. EPA suggested that a cost criterion of $2,000 per ton of NO_x reduction be used by the states to determine which types of stationary sources should be subject to control requirements. EPA concluded that electric utilities and fossil fuel-fired industrial boilers (>250 x 10^6 Btu/hr heat input capacity) should be the primary candidates for lowered NO_x emissions, with average costs under $2,000 per ton of NO_x removed for units burning coal or residual oil. Other types of sources, including smaller industrial boilers, pulp mill recovery furnaces, and lime kilns, were determined to likely have NO_x control costs exceeding $2,000/ton. However, individual states must decide on the specific control requirements for each stationary NO_x emission source.

In the 21 states, there are a large number of forest products manufacturing facilities, many of which operate combustion units, that are potential candidates for NO_x controls. These facilities will need to ensure the technical feasibility and cost-reasonableness of any proposed new NO_x emission restrictions. Mills with large coal and oil burning boilers have begun examining the costs and technical feasibility of various NO_x control measures such as fuel switching, boiler combustion modifications, and add-on controls. In addition to coal and residual oil, pulp mills also use distillate oil, natural gas, and wood residues as boiler fuels. Most of these fuels are burned in conventional steam generating boilers. In addition to conventional boilers, fluidized bed combustors and gas turbines are being used for steam and power generation at an increasing number of mills. In 2000, natural gas and wood residues each accounted for 33% of the fuel use in paper mill steam generating units, followed by coal (26%), and residual oil (8%) (NCASI 2002a). Distillate oil and miscellaneous fuels accounted for the remainder. Miscellaneous fuels include tire chips, petroleum coke, anthracite culm, fiber and paper-based fuels, wastewater treatment plant (WTP) residuals, rejects from old corrugated container processing, used oil, and refuse-derived fuel.

An earlier report (NCASI 1999) provided an overview of the mechanisms of NO_x formation and explained how an understanding of these mechanisms was important in the context of applying NO_x control technologies to many forest products industry (FPI) combustion units that are unique in their use of biomass fuels such as wood and black liquor. This report provides a review of the NO_x control techniques that could be considered applicable to industrial boilers and highlights those technologies currently available for controlling industrial boiler NO_x emissions. It also summarizes the various technological concerns raised in the literature or by individual companies and mills in their evaluations of potential NO_x control technologies to particular boilers in the context of RACT (Reasonably Available Control Technology), BACT (Best Available Control Technology), LAER (Lowest Achievable Emission Rate), or other regulatory permitting requirements. Finally, cost estimates generated by individual FPI companies for implementing such technologies are provided and compared with those developed by EPA.

2.0 NO_X LEVELS, CONTROL REQUIREMENTS, AND TYPES OF BOILERS

The level of NO_x control required for a boiler, along with the boiler design and operating conditions, will generally determine the technologies that are capable of achieving the requisite reduction. Some boilers are incapable of significant NO_x control by combustion modifications because of the nature of their design and operation. Most boiler designs do not, however, directly influence post-combustion NO_x control via flue gas treatment, such control being limited only by boiler operating considerations such as load swings and flue gas composition and other considerations such as space and geometry limitations, cost of control, etc. Gas and oil-fired boilers that need to achieve NO_x removal efficiencies in excess of about 75% and solid fuel-fired boilers needing NO_x removal efficiencies in excess of about 30% are generally forced to look at post-combustion NO_x control. Boilers subject to lesser NO_x removal requirements can resort to various combinations of combustion modifications.

2.1 NO_x Levels and Control Requirements for Boilers

Table 2.1 presents the uncontrolled NO_x emission factors for typical industrial boilers with heat inputs >100 x 10^6 Btu/hr as given in EPA's AP-42 documents for bituminous coal, oil, gas (USEPA 1998a, 1998b, 1998c), and wood-fired boilers (USEPA 2001). In September 1998, EPA revised NO_x emission limits contained in the Subpart Db NSPS (new source performance standards) which apply to new industrial boilers with heat input capacities of 100 x 10^6 Btu/hr or greater. Table 2.1 also shows the revised Subpart Db emission limits for various types of boilers. The Db limits are 30-day rolling averages and apply to all boilers for which construction started after July 9, 1997. Limits for natural gas and distillate oil-fired boilers were left essentially unchanged from the earlier NSPS Subpart Db standards promulgated on June 19, 1984, while limits for coal and residual oil were lowered significantly. The basis for the revised standards for coal- and residual oil-fired boilers is the application of combustion modifications and selective catalytic reduction (SCR) flue gas treatment, although EPA claims selective non-catalytic treatment (SNCR) may be sufficient for residual oil-fired units. While no specific limits were promulgated for boilers firing wood residues under Subpart Db, any boiler firing more than 10% of any fossil fuel on an annual basis is subject to the NO_x emission limit for the fossil fuel. Thus, boilers firing coal or oil with wood would have a limit of 0.2 lb/10^6 Btu.

Also shown in Table 2.1 are the corresponding percentage reductions in NO_x emissions expected from the uncontrolled or baseline levels for boilers (as indicated by the AP-42 factors) that become subject to the revised NSPS. It should be noted that for large electric generating units (EGUs) in states subject to the NO_x SIP call, EPA has recommended that they be assigned NO_x limits of about 0.15 lb $NO_x/10^6$ Btu heat input, representing an average cost-effectiveness of $1,720 per ozone season ton NO_x removed in 1997 dollars. Very few, if any, boilers in the FPI are classified as EGUs. Large non-EGUs, i.e., industrial boilers with coal or residual oil heat input capacities over 250 x 10^6 Btu/hr, are recommended by EPA for a 60% reduction in NO_x emissions from baseline levels.

Table 2.1 AP-42 NO_x Emission Factors (boilers with >100 x 10^6 Btu/hr heat input) and NSPS for Industrial Boilers (>100 x 10^6 Btu/hr heat input)[a]

Fuel Type	AP-42[b] Uncontrolled Emission Factors lb/10^6 Btu	Subpart Db Boilers Built After July 9, 1997 lb/10^6 Btu	Reduction Required[c] to meet Subpart Db Limits Percent
Natural Gas	0.17 - 0.27[d]	0.10 - 0.20[e]	26 to 41
Residual Oil	0.21 - 0.31[d]	0.20	5 to 35
Distillate Oil	0.16	0.10 - 0.20[e]	0 to 38
Coal			
Pulverized	0.39 to 1.24[d]	0.20	49 to 84
Stoker	0.30 to 0.44[f]	0.20	33 to 55
Fluidized Bed	0.20 to 0.61[g]	0.20	0 to 67
Wood[h]			
Bark/Wet Wood	0.22	none	NA
Dry Wood	0.49	none	NA

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[a] 60% reduction from baseline expected for non-EGU boilers subject to SIP Call; [b] uncontrolled emission factors, converted using 1,020 Btu/ft^3 gas, 150,000 Btu/gal residual oil, 12,500 Btu/lb coal and 4,500 Btu/lb as-fired wood; [c] from uncontrolled AP-42 factor; [d] lower for tangential and higher for wall-fired boilers; [e] lower factor for low and higher factor for high heat release rates; [f] spreader, overfeed, and underfeed stokers; [g] circulating bed and bubbling bed; [h] note that wood-fired boilers firing >10% fossil fuel are subject to limits for fossil fuel

Besides boilers firing wood residues or fossil fuels, NO_x emissions from kraft pulp mill boilers can also result from the burning of stripper off-gases (SOGs) containing ammonia. The burning of SOGs in five power boilers resulted in NH_3-to-NO_x conversion rates ranging from -11 to 34% with changes in baseline NO_x levels ranging from -0.05 to 0.14 lb/10^6 Btu (NCASI 2002b).

2.2 Description of Boiler Types

Steam can be generated in many different types of combustion devices. The vast majority of pulp and paper mills and wood products plants use conventional boiler technology, where the fuel is combusted in a furnace chamber and the resulting heat is used to generate steam inside water tubes. The water tubes are located near the furnace walls and above the furnace. Water tube boilers are generally used in industrial applications to generate steam at rates of 20,000 lb/hr and greater. There are approximately 1,300 boilers at U.S. pulp and paper mills (about 2.5 boilers per mill), and most of these have steam generating capacities of 20,000 lb/hr and greater. Conventional boilers are often characterized according to whether they are factory assembled (package) or assembled at the mill (field-erected). In addition, boilers can be categorized by their fuel burning capability (gas, liquid, solid), fuel firing mechanism (pulverized coal, cyclone, stoker, mass feed), grate type (vibrating, stationary, chain) and burner arrangement (tangential, wall-fired). These latter characteristics influence emission rates of NO_x.

Most paper mill boilers are equipped to burn more than one fuel to ensure steam availability and to provide it at the lowest possible cost. Package boilers frequently are equipped to burn either natural gas or oil. Boilers built primarily for coal firing often have the capability to burn either gas or oil, or both. Most of the boilers that burn wood have the capability to co-fire one or more fossil fuels. In fact, very few boilers at pulp and paper mills run exclusively on wood residues.

Besides conventional boilers, a few mills use fluidized bed combustors for steam generation. Fluidized bed units typically burn mixtures of solid fuels (coal, wood, wastewater treatment plant residuals), although gas or oil may serve as a back-up. The fuels are combusted in a moving bed of sand or other solid heat transfer media. Water tubes for steam generation are located in the moving bed and above the bed. These units are increasingly used for solid fuel combustion because of efficiency and environmental control considerations.

Gas turbines are used at about 25 mills for steam and electricity cogeneration. In these units, combustion air is compressed before introduction into a combustion chamber with the fuel, which is almost always natural gas (distillate oil is normally used only as a back-up fuel). Combustion takes place at very high temperatures, and the energy from the expanding combustion gases is converted to mechanical energy. About one-half of the energy is used to drive the compressor, and the remainder is used in the turbine to generate electricity. The hot gases are then passed into a heat recovery steam generator. The heat content of these gases can be increased to generate additional steam by burning fuel in duct burners prior to the steam generator.

3.0 REVIEW OF NO_X CONTROL TECHNIQUES FOR INDUSTRIAL BOILERS

There are two principal methods of industrial boiler NO_x emissions control: combustion modification and flue gas treatment. Combustion modifications are often associated with improving boiler performance. Flue gas treatment can occur both within the boiler and at several points along the path of the flue gas from the boiler to the stack. Other pre-combustion techniques such as fuel denitrogenation to reduce “fuel NO_x” have shown little promise. Biomass fuel gasification could lead to lower NO_x emissions, but this technology is still in the early stages of development.

3.1 Combustion Modifications

Combustion modifications are the most common, commercially available means of controlling NO_x emissions from fossil fuel-fired boilers. These can be brought about either by effecting relatively simple modifications of operating conditions or by incorporating more elaborate modifications of the combustion facility. Retrofit applications of NO_x controls by combustion modification usually proceed in several stages. First, fine tuning of combustion conditions by lowering excess air and adjusting burner settings and air distribution may be attempted. Next, minor modifications such as biased burner firing or taking burners out of service may be implemented. Finally, if further reductions are desired, other retrofits such as installation of overfire air ports, flue gas recirculation systems, and/or low-NO_x burners may be employed (USEPA 1992).

Combustion modifications can be divided into five categories: a) low excess air (LEA), b) staged combustion, c) temperature reduction technologies, d) low NO_x burners (LNB), and e) in-furnace destruction.

3.1.1 *Low Excess Air in the Flame Zone (LEA)*

By reducing the amount of excess air, and therefore excess oxygen, in the local flame zone, moderate reductions in NO_x emissions may be possible. Operating the burners with low excess air (<5% for oil and gas-fired boilers) results in lower NO_x emissions (both fuel and thermal NO_x) and higher boiler efficiencies. Unfortunately, low excess air operation has proven to yield only moderate NO_x reductions, if any (Wood 1994). Ten to 20% NO_x reduction is believed feasible by LEA for every 1% reduction in furnace O_2 levels (Makanski 1988). However, this technique is limited by the production of smoke, high CO emissions and possibly other problems within the boiler itself such as increased fouling and corrosion due to the reducing atmosphere (Jones 1994). LEA is not in widespread use as an NO_x control technique for industrial boilers, but it is used for energy conservation (Jones 1994).

3.1.2 *Staged Combustion or Off-Stoichiometric Combustion*

Staged combustion or off-stoichiometric combustion is one of the oldest modification techniques for NO_x control. Diverting a portion of the total amount of air required through separate ports, generally located above the burners, creates a “fuel-rich” zone (also known as air staging). The fuel-rich conditions result in lower peak temperatures and thus, lower thermal as well as fuel nitrogen-generated NO_x. Staged combustion can be accomplished by various in-furnace techniques such as a) overfire air (OFA), b) burners out of service (BOOS) and c) biased burner firing (BBF) or air/fuel mixing, each of which is described briefly below. These techniques are generally applicable to larger, multiple burner combustion devices (Wood 1994).

Overfire Air (OFA)

In OFA, about 10 to 20% of the combustion air flow is directed to separate air ports located downstream of the burners. OFA works by reducing the excess air in the burner zone, thereby enhancing the combustion staging effect and reducing NO_x emissions. Residual unburned material, such as CO and unburned carbon, which inevitably escapes the main burner zone, is oxidized as the overfire air is admixed later. This modification is more attractive in original designs than in retrofit applications because of cost considerations, including cost of additional ductwork, furnace penetrations, extra fan capacity, and physical obstructions that make retrofit difficult in some installations (USEPA 1992). When implemented, 15 to 30% NO_x reductions with OFA alone are expected (Makanski 1988). OFA is a very effective technique for NO_x reduction, especially for tangentially-fired boilers (USEPA 1992), and may be used with all fuels and most combustion systems, including stoker/grate units (Jones 1994). Operational problems resulting from OFA can include decreased combustion efficiency and deterioration of final steam conditions.

Burners Out of Service (BOOS)

BOOS is a relatively simple technique used mostly in retrofit situations (suspension-fired coal and oil/gas-fired boilers) wherein multiple burners exist and fuel flow is blocked to an upper level of burners, allowing only air to pass through these. To avoid flame stability and vibration problems, the number of burners taken out of service should not exceed 25% (USEPA 1991). Operational problems resulting from BOOS can include corrosion and soot/slag formation (USEPA 1991).

Biased Burner Firing

In biased burner firing (BBF), also known as air/fuel mixing or fuel biasing, the furnace is divided into a lower, fuel-rich zone and an upper fuel-lean zone to complete the burnout. This technique has been proven only for oil/gas-fired utility boilers (Makanski 1988). A 20% reduction in NO_x can be expected.

3.1.3 *Temperature Reduction Technologies*

Several NO_x reduction technologies employ some method of reducing peak flame temperatures to minimize thermal NO_x formation. These include a) flue gas recirculation (FGR), b) reduced air preheat, c) steam and water injection, and d) decreased load.

Flue Gas Recirculation (FGR)

In FGR, a portion of the combustion flue gas is brought into the combustion zone (up to 20% of the flue gas). This has typically been accomplished using a recirculation fan, but if there is already a forced-draft (FD) fan installed, some recirculation can be educted in the discharge or the suction of the FD fan. The flue gas acts as a heat sink, lowering the flame temperature. It also reduces the oxygen concentration. Both these effects result in lower thermal NO_x. Reported flame temperatures (gas/oil) are 3,500°F with no recirculation and 2,900°F at 20% FGR. It should be noted that the onset of thermal NO_x occurs around 2,800°F, and NO_x generation increases exponentially with temperatures beyond 2,800°F.

High capital expenditures are necessary to install new ductwork, recirculation fans, devices to mix flue gas with combustion air, etc. Flue gas is typically taken from a stack breaching at about 300 to 400°F and mixed with the secondary combustion air (wind box). As only thermal NO_x can be controlled by this technique, it is especially effective only in oil and gas-fired units. In fact, FGR is probably the most effective and least troublesome system for NO_x reduction for gas-fired combustors (Wood 1994). A 20 to 30% reduction in NO_x is expected (Makanski 1988). FGR is most effective when used in conjunction with air and/or fuel staging (Jones 1994). Once the favored method of industrial-boiler NO_x control, today it has lost some of its favor due to a better understanding of the high capital costs and FGR fan and operation and maintenance costs involved, in addition to loss of boiler efficiency (Jones 1994). FGR is more adaptable to new designs than as a retrofit application (USEPA 1992).

Reduced Air Preheat (RAP)

Lowering the amount of combustion air preheat results in a lower primary combustion zone peak temperature, and thus lower thermal NO_x emissions. The energy penalty usually makes this option unfavorable (Yaverbaum 1979). A rule of thumb is a 1% efficiency loss for each 40°F reduction in preheat (Wood 1994). As in FGR, RAP only lowers thermal NO_x, and thus is economically attractive for only natural gas and distillate fuel oil combustion (USEPA 1992).

Steam and Water Injection

Flame quenching by the addition of steam or water in the combustion zone is an effective control technology for oil/gas-fired burners, although a significant energy penalty could ensue. Oil/water emulsions can realize a similar response as steam/water injection (Jones 1994). Up to 70% suppression of NO_x formation in gas turbines is believed feasible (Makanski 1988).

Decreased Load

A reduction in the percentage of rated capacity leads to lower "volumetric heat release rates" in the boiler, and correspondingly lower flame temperatures and NO_x formation. Wasted load capacity is a definite disadvantage. Reduced mass flow can also cause improper fuel-air mixing during combustion, creating carbon monoxide and soot emissions (USEPA 1992).

3.1.4 *Low NO_x and Ultra Low NO_x Burners (LNB & ULNB)*

Low NO_x burners (LNBs) are designed to mix fuel and air in a controlled pattern that sustains local fuel-rich regions, keeps the temperatures down, and dissipates heat quickly. By controlling the mixing of the fuel and air, the combustion process can be initiated at the burner throat and the zone of complete combustion can be varied in the furnace chamber, resulting in elongated flames as compared to short, intense flames. Virtually all of the boiler and burner vendors have developed LNBs for retrofit (Makanski 1988). Both staged air and staged fuel combustion principles are employed in LNBs. Combustion modification with LNBs is used in both gas/oil-fired and coal-fired units. A full LNB retrofit can be expected to reduce NO_x levels by about 50% (Makanski 1988). Flame containment, specifically sidewall and/or rear-wall flame impingement, is a challenge in the smaller boilers, particularly in a high-space-heat-release-rate package boiler. While LNBs use staged fuel to reduce NO_x, by contrast, ultra low NO_x burners or ULNBs reduce NO_x by inducing the internal circulation of fuel gas within the heater. ULNBs also tend to have large diameters, but shorter flame lengths and may be easier to retrofit.

Considered a modification of the low NO_x burner, slagging combustors involve high temperature combustion of coal in an air-deficient chamber. Ash is removed as a liquid slag and NO_x formation is suppressed. The gasified coal is then combusted in the existing furnace cavity. Because their combustion characteristics are similar to those of cyclone-fired coal boilers (coal ash removed as liquid slag), slagging combustors are thought to be particularly good for retrofitting the latter (Makanski 1988).

3.1.5 *In-Furnace Destruction*

Also known as “reburning,” “off-stoichiometric combustion” or “fuel staging”, in this technique from 15 to 25% of the total fuel input is diverted to a second combustion zone downstream of the primary zone (Makanski 1988). The fuel in the fuel-rich secondary zone acts as a reducing agent, reducing NO formed in the primary zone to N_2. Low nitrogen-containing fuels such as natural gas and distillate oil are typically used for reburning to minimize further NO_x formation. For example, the METHANE de-NOX reburning process utilizes the injection of natural gas together with recirculated flue gases (for enhanced mixing) to create an oxygen-rich zone above the combustion grate. Overfire air is then injected at a higher furnace elevation to burn out the combustibles (Loviska et al. 1998). This process is claimed to yield between 50 and 70% NO_x reduction and be suitable for all solid fuel-fired stoker boilers (coal, biomass, municipal solid waste, RDF, etc.). However, it has only been demonstrated on one pulp mill boiler (Rabovitser et al. 2000), one municipal waste combustor (Abbasi et al. 1998) and one 60 MWe stoker coal-fired unit (Loviska et al. 1998) in the U.S. The Gas Research Institute (GRI), which developed this process, has plans to apply METHANE de-NOX to several pulp and paper mill wood-fired stoker units (Schrecengost et al. 2002).

Fuel Lean Gas Reburn (FLGR) is GRI’s technology that offers operators of electric utility boilers a low cost approach for moderate levels of NO_x reduction (about 30% to 50%). Natural gas is injected into the upper furnace region in small quantities (under 10% of heat input, typically 5-7% of total heat input). Unlike conventional gas reburning technology, which requires overfire air (OFA) and 15% to 25% of the heat input from natural gas, with FLGR the furnace stays fuel-lean overall and does not require OFA. Therefore, furnaces that could not utilize conventional reburning due to the need for OFA and do not require the higher NO_x reductions of conventional reburning (over 60% in some cases), may be able to use FLGR.

3.2 Flue Gas Treatment

Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR), and to a lesser extent catalytic or non-catalytic oxidation with scrubbing, are among the only proven, viable, full-scale post-combustion flue gas treatment techniques for industrial boilers at the current time. Other advanced post-combustion treatment options are currently being developed, some awaiting results of pilot stage results, and others awaiting the enactment of more stringent NO_x control requirements before their full-scale use can be put to test.

3.2.1 *Selective Non-Catalytic Reduction (SNCR)*

SNCR involves the injection of urea, ammonium hydroxide, anhydrous ammonia, or aqueous ammonia into the furnace exit region where the flue gas is in the range of 1,600 to 1,900°F (USEPA 1997). NO_x is reduced to N_2 and H_2O. The primary reaction sequences for SNCR are shown in Figure 3.1 (ABB 1997). This figure does not show any of the potential side reactions and undesirable competing reactions which contribute to the complexity of the overall SNCR reaction mechanism.

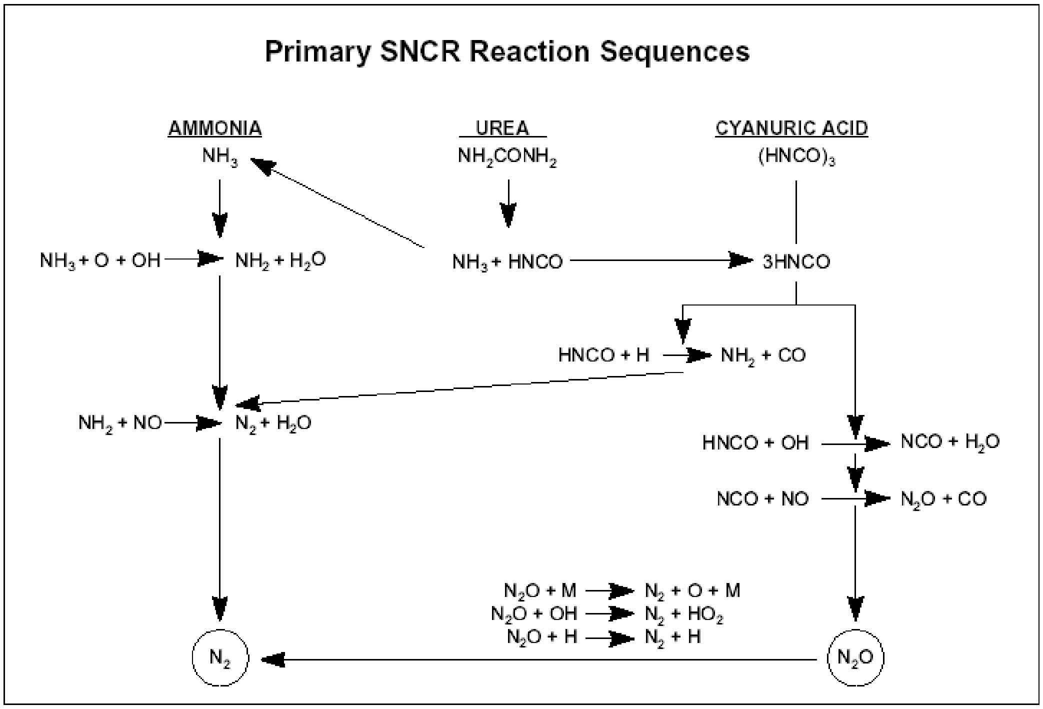

Figure 3.1 Primary SNCR Reaction Sequences

One concern about this process is its ability to perform adequately under changing load and fuel conditions (Jones 1994), although the use of computational fluid dynamics (CFD) modeling and the design of multiple level injections in the boiler is reported to alleviate some of this concern (Sun 2002). The Exxon Thermal DeNOx process relies on the injection of ammonia, while Fuel Tech's NOxOUT process relies on the injection of urea into the boiler. Both ammonia and urea bring about gas phase reduction of NO_x to nitrogen. A portion of the NO reduction by SNCR systems, usually around 5%, is due to transformation of NO to N_2O, which is a greenhouse gas (USEPA 1998d).

Thermal DeNOx

The thermal DeNOx process, developed and marketed by Exxon Research and Engineering Company (Hurst 1983), selectively reduces NO_x to molecular nitrogen and water by using ammonia injection into the air-rich flue gas in the temperature range of 1600 to 2200°F, temperatures typically found in the upper portions of the furnace (superheater section or before air preheater). The actual chemical mechanism of the process is quite complex, involving 31 significant chemical reactions (Hurst 1983). NO_x reductions as high as 60 to 70% have been achieved in some industrial applications. The reduction efficiency is affected by the NH_3 feed rate relative to NO_x concentrations, by the degree of flue gas thermal stratification in the ammonia injection section, and by the flue gas residence time within the appropriate temperature window.

The reaction predominates around a temperature of 1740°F (USEPA 1981). For temperatures above 2000°F, the injected ammonia is oxidized to NO_x, and for temperatures below about 1560°F the reaction proceeds slowly and the NO reduction falls off drastically, resulting in significant ammonia slippage (USEPA 1981). The oxidation of ammonia to NO, unreacted ammonia or ammonia slippage and reduction of NO in NH_3-NO mixtures, is discussed further in NCASI Technical Bulletin No. 802 (NCASI 2000).

The ammonia injected must be diluted with air or steam to allow for good mixing. The injection is usually accomplished by using a multiport injection grid to allow for varying flue gas temperatures due to boiler load swings. Problems with NH_3 injection include ammonia slippage, fouling of air preheater surface by ammonium sulfate/bisulfate formation, and maintaining optimum reaction temperatures for the NH_3-NO reaction (USEPA 1981).

NOxOUT

Research into the injection of urea (solid or aqueous solution) in a manner similar to ammonia was first carried out by the Electric Power Research Institute (DePriest, Jarvis, and Cichanowicz 1989). Known as the NOxOUT process, it has received increased attention on account of both the reduced cost and reduced danger of handling urea as compared with ammonia (Sun 2002). Also, it is believed that urea/water injection parameters can be more easily matched to furnace temperature, providing better load-following capability and resulting in reduced hardware requirements such as injection grids (Makanski 1988). The NOxOUT process is based upon the following chemical reaction that ideally occurs in the temperature range of 1700 to 2000°F (Muzio and Anand 1976), but could be operated at temperatures from as low as 1,600°F to as high as 2,200°F (Sun 2002).

$$2\ NO + NH_2CONH_2 + 1/2\ O_2 \Rightarrow 2\ N_2 + CO_2 + 2\ H_2O$$

The problems of ammonia slippage and heat transfer surface fouling with byproduct formation also exist with the NOxOUT process.

Six factors directly affect the performance of urea- or NH_3-based SNCR systems (USEPA 1997). These are a) inlet NO_x level, b) temperature, c) mixing, d) residence time, e) reagent-to-NO_x ratio, and f) fuel sulfur content. Lower inlet NO_x concentrations reduce the reaction kinetics and hence the achievable NO_x emissions reductions. As mentioned above, temperatures below the desired window result in ammonia emissions (slip), and temperatures above the desired window result in NH_3 being oxidized to NO_x. Mixing becomes an important consideration in regions distant from an injection nozzle where the level of turbulence is reduced and stratification of the reagent and flue gas will probably be a greater problem, especially at low boiler loads (USEPA 1997). Residence time becomes important to allow the desired reactions to go to completion. Small, packaged, water tube boilers and boilers with varying steam loads are therefore difficult applications for SNCR (USEPA 1997). As higher than the theoretical NH_3 to NO_x ratios are generally required to achieve desired NO_x emission reductions, a trade-off exists between NO_x control and the presence of NH_3 in the flue gas. The main disadvantage of SNCR is the low NO_x reduction that is experienced when the allowable ammonia slip is low (as in the Houston area, Southern California and Europe). Finally, in the case of high sulfur fuels, excess NH_3 can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit on downstream equipment leading to plugging and reduced heat transfer efficiencies.

3.2.2 *Selective Catalytic Reduction (SCR)*

The SCR process also uses ammonia injection, but the reduction reactions are carried out on the surface of a catalyst operating at temperatures between 450°F and 750°F. The following overall reactions are known to occur on the catalytic surface:

$$4\,NH_3 + 4\,NO + O_2 \overset{\text{catalyst}}{\Rightarrow} 4\,N_2 + 6\,H_2O$$

$$8\,NH_3 + 6\,NO_2 \overset{\text{catalyst}}{\Rightarrow} 7\,N_2 + 12\,H_2O$$

The active compound which promotes the NH_3-NO_x reaction may be composed of a precious metal (e.g., Pt, Pd), a base metal oxide, or a zeolite (USEPA 1997). Precious metal catalysts are used in clean fuel applications and at lower temperatures than the base metal oxide or zeolite catalyst. The most common base metal oxide catalysts are vanadium/titanium based, with V_2O_5 as the active material and TiO_2 as the support material. The zeolite catalysts are stable over a wider temperature window than other types of catalysts. Optimum NO_x reduction occurs at catalyst bed temperatures between 600 and 750°F for conventional (vanadium or titanium-based) catalyst types, and between 470 and 510°F for platinum-based catalysts (USEPA 1991). An ammonia to NO ratio of 1:1 has typically reduced NO_x by 80 to 90%, with a leak rate of less than 20 ppm (USEPA 1981). The reactor is usually located between the boiler and air preheater. NO_x control efficiencies are typically in the range of 70 to 90%, depending on the type of catalyst, amount of NH_3 injected, the initial NO level, and the age of the catalyst.

The performance of an SCR system is also affected by six factors (USEPA 1997). These are a) NO_x level at SCR inlet, b) flue gas temperature, c) NH_3-to-NO_x ratio, d) fuel sulfur content, e) gas flow rate, and f) catalyst condition. For SCR, when inlet NO_x concentrations fall below 150 ppm, the reduction efficiencies decrease with decreasing NO_x concentrations (USEPA 1997). Each type of catalyst has an optimum operating temperature range. Temperatures below this range result in ammonia emissions (slip), and temperatures above the desired range result in NH_3 being oxidized to NO_x. For up to about 80% NO_x reduction efficiencies, a 1:1 NH_3:NO_x ratio is sufficient. For higher efficiencies, higher reagent to NO_x ratios are required which may result in higher NH_3 slip. In the case of high sulfur fuels, excess NH_3 can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit and foul downstream equipment. SCR application experience in the case of medium-to-high sulfur fuels is limited. For a given flue gas flow rate, the catalyst structural design should be chosen so that the residence time needed for the reduction reactions to take place on the catalyst surface is achievable.

Catalysts degrade over time due to poisoning, fouling, thermal stress, erosion by particulate, etc. NO_x removal decreases as the catalyst gets deactivated. Catalysts are a major component of the cost of SCR.

SCR is considered a high-efficiency removal device. Today, SCR has become a common feature of new gas-turbine cogeneration and combined cycle systems in the U.S. (Jones 1994). Several utility boilers have also been equipped with the SCR NO_x control technology. By the year 2004, in excess of 100 GW of coal-fired capacity in the U.S. may be equipped with this technology in order to mitigate "seasonal" ozone production. As a result, in the 25 years since the first commercial installations in Japan, SCR technology has evolved in response to changing application conditions, with present day catalysts featuring thinner walls, improved mass transfer and activity, and better poison resistance than earlier generation catalysts (Cichanowicz and Muzio 2001).

Major problems with SCR processes include corrosion due to higher flue gas acid dew points, and formation of solid ammonium sulfate and ammonium bisulfate, particularly in high sulfur oil-fired or coal-fired boilers. These could deposit on the air preheater surface to reduce heat transfer efficiencies. Ammonia slippage is also a potential problem. Arsenic poisoning has been demonstrated as a major contributor to catalyst deactivation, requiring a minimum quantity of available calcium in the fly ash (which could be obtained by injecting or adding limestone or lime to coals) (Cichanowicz and Muzio 2001). Because of poisoning by trace metals or erosion by fly ash, catalysts lose activity over time. Although a proven technology for larger units (>20 MW), it is not in widespread use for smaller industrial boilers, primarily due to cost considerations. Catalyst regeneration rather than replacement, better reactor design and layout to promote contacting of reagent and flue gas, etc. may eventually improve performance at lower cost for industrial boilers.

3.2.3 *Scrubbing After Catalytic Oxidation or Ozone Injection*

Unlike NO, which is neutral, NO_2 can be scrubbed with caustic solutions. Several vendors have proprietary technologies for the catalytic oxidation of NO in scrubbing systems. Catalytic scrubbing is generally considered economical only if a caustic scrubber already exists. A scrubber with a long residence time and multiple scrubbing stages, such as a packed bed, is the main consideration in increasing efficiencies in most catalytic scrubbing processes (Bradford, Grover, and Paul 2002).

An alternative approach to catalytic scrubbing is the injection of ozone into the flue gas upstream of the scrubber. Ozone injection is said to achieve up to a 95% NO reduction, because ozone reportedly converts both the NO and NO_2 to N_2O_5, which is more soluble in caustic solution than NO or NO_2. Important design considerations for ozone injection include a) a large oxygen requirement since a 10% ozone stream is generated from oxygen using an electric arc, b) a low temperature (below 300°F) to prevent the ozone from decomposing, and c) a long enough residence time to allow the reaction to go to completion (Bradford, Grover, and Paul 2002). Cost considerations for the ozone generating equipment have been a major hindrance in the past.

4.0 NO_X CONTROL TECHNOLOGIES TYPICALLY APPLICABLE TO FPI BOILERS

This section discusses the various types of conventional fossil fuel and wood-fired boilers, turbines and fluidized bed combustion units operating in the FPI, the fuels fired in these units, and the type of NO_x control technologies generally considered applicable.

4.1 Conventional Boilers Firing Fossil Fuels, Wood, or Both

4.1.1 *Natural Gas*

Natural gas contains a high percentage (generally >85%) of methane and varying amounts of ethane, propane, butane, and inerts (typically N_2, CO_2, and helium). Natural gas is burned in package boilers (these units generally have heat input capacities under 100 x 10^6 Btu/hr) or in field-erected boilers (mainly over 100 x 10^6 Btu/hr). Field-erected boilers may be wall-fired (multiple burners on a wall) or tangential-fired (rows of fuel and air nozzles in each of the four corners).

The principal mechanism of NO_x formation in natural gas combustion is by the “thermal” NO_x mechanism (thermal fixation of atmospheric nitrogen). NO_x emissions are dependent on the combustion temperature and the rate of cooling of the combustion products.

Several combustion modification techniques are available to reduce the amount of NO_x formed in natural gas-fired boilers and turbines. The two most prevalent ones are flue gas recirculation (FGR) and low-NO_x burners (LNB). FGR reduces formation of thermal NO_x by reducing peak temperatures and limiting availability of oxygen. LNB reduces formation of thermal NO_x by delayed combustion (staging), resulting in a cooler flame. In conjunction with FGR, the burners can achieve NO_x emission reductions of 60-90%. Other techniques include staged combustion and gas reburning. In general, these techniques have been incorporated in newer boilers; thus their NO_x emissions are lower than those of older units. There are also many add-on control technologies to reduce NO_x emissions such as selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR), although these are not commonly used because of cost considerations. The addition of NO_x control systems such as low-NO_x burners and flue gas recirculation may reduce combustion efficiencies and result in higher CO emissions (USEPA 1998c).

4.1.2 *Fuel Oil*

Two major types of oil are burned by combustion sources in the FPI: distillate and residual. Distillate oil is a relatively clean burning fuel that has negligible nitrogen. The heavier residual oils contain significantly higher levels of nitrogen. As for natural gas, distillate or residual oils are burned in either package boilers (generally having heat inputs less than 100 x 10^6 Btu/hr) or in field-erected boilers (heat inputs over 100 x 10^6 Btu/hr). Field-erected boilers may be normal-fired (wall) or tangential-fired.

NO_x emissions from fuel-oil combustion depend on the grade and composition of the fuel oil, the type and size of the boiler, and the firing practices used. NO_x emissions from burning distillate oil are similar to those from natural gas. Many paper mill boilers that mainly burn natural gas can also burn distillate oil during cold weather gas supply curtailments.

NO_x emissions are formed from the nitrogen in the residual oil (“fuel” NO_x) and from high temperature oxidation of nitrogen in the combustion air (“thermal” NO_x). “Fuel” NO_x can account for 60 to 80% of the total NO_x formation, although the nitrogen levels in residual oil can vary from 0.1 to almost 1% and the percent conversion of fuel N to NO_x can range from 20 to 90%. NO_x emissions from tangentially-fired units are, on average, lower than those from horizontally opposed wall-fired units.

For fuel oil-fired boilers, NO_x emissions can be controlled by fuel substitution/alteration, combustion modification, and post-combustion control. Fuel substitution reduces NO_x by burning an oil with lower N content. For boilers burning residual oil, fuel NO_x is the dominant mechanism for NO_x formation, and thus the most common combustion modification technique is to suppress combustion air levels below the theoretical amount required for complete combustion. Several combustion modification techniques are available to reduce the amount of NO_x formed in fuel oil-fired boilers, including low excess air, burners out of service, biased-burner firing, flue gas recirculation, overfire air, and low-NO_x burners. NO_x reductions from 5-60% may be expected from these techniques. Post-combustion controls include SNCR and SCR. NO_x reductions from 25-40% and from 75-85% may be expected from use of SNCR and SCR systems on oil-fired boilers, respectively (Pakrasi 2000), although as shown later, the cost-effectiveness for these add-on controls could well exceed the threshold of $2,000/ton NO_x removed advocated by EPA.

4.1.3 *Coal*

Bituminous and subbituminous coals are the main types of coal burned in paper industry boilers. No use of lignite or anthracite coal is known at the present time. Boiler types include pulverized coal, stoker, cyclone, fluidized bed, and mass feed units. The 2000 NCASI survey of pulp and paper industry boilers showed there were 105 pulverized coal, 67 spreader stoker, eight cyclone, eight fluidized bed, and 11 underfeed stoker coal-fired boilers operating during that year. Over half of these units were also capable of burning wood fuels and/or wastewater treatment plant residuals (NCASI 2002a).

Pulverized coal-fired boilers can be wall-fired (single or multiple burners on one or opposing walls) or tangential-fired (burners and air nozzles mounted in the corners of the furnace). In cyclone boilers, the coal is fed tangentially, with primary air, into a horizontal cylindrical furnace. There are two main types of stokers. The underfeed stoker is either a horizontal-feed, side ash-discharge type or a gravity-feed, rear ash-discharge type. The spreader stoker uses mechanical or pneumatic feeders to distribute coal uniformly over the surface of a moving grate. Fluidized bed combustors (FBCs) can be atmospheric or pressurized. The atmospheric FBC can be of the bubbling bed design or the circulating bed design (USEPA 1998a).

NO_x emissions from coal combustion are considerably higher than those from gas or oil. NO_x formation results from thermal and fuel mechanisms. Fuel nitrogen can account for up to 80% of the total NO_x formed. Coal nitrogen contents range from 0.5 to 2% (USEPA 1998a). Emissions of NO_x are highest for cyclone boilers, followed by pulverized coal, stokers, and mass feed units.

Just as in fuel oil combustion, NO_x emissions can be controlled by fuel substitution/alteration, combustion modification and post-combustion control. NO_x reductions can be achieved by burning a coal with lower N content. NO_x emissions from coal-fired boilers can be controlled by combustion controls and post-combustion controls. Combustion controls involve a) reducing peak temperatures in the combustion zone, b) reducing gas residence time in the high-temperature zone, and c) air or fuel staging by operating at an off-stoichiometric ratio by using a rich fuel-air ratio in the primary flame zone and lower overall excess air conditions (Pakrasi 2000). The use of combustion controls depends on the type of boiler and the method of coal firing. Low-NO_x burners and overfire air (OFA) have been successfully applied to tangential- and wall-fired units, whereas reburning is the only current option for cyclone boilers. For large coal-fired boilers, the most developed and widely applied post-combustion NO_x control technology is SCR. Catalyst deactivation and residual NH_3 slip are the two key operating considerations in an SCR system (Pakrasi 2000). The use of SNCR systems on coal-fired boilers is still in the development stage. NO_x reductions from 30-70% and from 60-90% may be expected from use of SNCR and SCR systems on coal-fired boilers, respectively (Pakrasi 2000). The shortcomings of installing SCR systems on industrial coal-fired boilers are discussed later.

4.1.4 *Wood Residues*

A majority of chemical wood pulp mills that debark logs on site burn the bark and other wood residues in boilers to generate steam and power. Although smaller boiler types such as the Dutch oven and fuel cell oven are sometimes utilized, the majority of boilers with steam generation rates exceeding 100,000 lb/hr are of the spreader stoker type. At pulp and paper mills in 2000, there were 9 Dutch ovens, 13 fluidized bed boilers, 38 pulverized coal-fired boilers, 1 gasifier and 141 spreader stokers that burned wood fuels (NCASI 2002a). Of the 202 boilers firing wood residues, 72 could co-fire coal, 93 could co-fire residual oil, 25 could co-fire distillate oil, 111 boilers co-fired natural gas, 76 burned waste treatment system residuals, and 25 burned tire-derived fuel. The wood products industry burns several types of wood residues including bark, sawdust, planer shavings, sander dust, and trim from lumber cutting and plywood manufacture in a variety of boilers including stokers, fuel cells, Dutch ovens, and suspension burners.

Using a 65 kW refractory-walled reactor to study biomass combustion under conditions typical of the suspension burning phase in a spreader-stoker-fired boiler, Winter et al. (1989) showed that wood-fired boiler NO_x emissions were strongly dependent on combustion zone oxygen concentration and the nitrogen content of the biomass fuel. However, these emissions were relatively insensitive to both temperature and moisture content. In other words, NO_x emissions from wood residue combustion are mainly the result of "fuel NO_x." This is consistent with the observation that "thermal NO_x," or NO_x generated by the thermal fixation of atmospheric nitrogen, usually sets in only at temperatures exceeding about 2,800°F, and wood combustion in boilers seldom reaches such high temperatures. The dependence of NO_x emissions on excess air levels was confirmed by Philo, Chapman, and Mirolli (1989) who conducted parametric tests on a 550,000 lb steam/hr wood-fired stoker unit varying the level of excess air. They found that the NO_x emissions increased from 85 to 170 ppm when the flue gas O_2 content rose from 1.9 to 6.4%.

No systematic study has been conducted to examine the relationship between wood nitrogen content and emissions of NO_x, although NCASI has begun a study to look at this relationship (NCASI 2003). Wood and bark nitrogen contents typically range from 0.1 to 0.2% (dry basis), lower than most coals and residual fuel oils. Thus, average NO_x emissions from wood combustion in typical pulp mill boilers would be expected to be lower than those from coal or residual oil combustion, but slightly higher than those from natural gas combustion. However, if the wood fuel burned contains nitrogen from other sources (e.g., sander dust from wood products operations using urea formaldehyde resins), higher NO_x emissions can be expected. Also, certain types of wood residues (e.g., juvenile woods) are known to contain somewhat higher levels of nitrogen (0.2 to 0.4% range).

Common combustion modification techniques used to control fuel NO_x by suppressing combustion air levels to below the theoretical amount required for complete combustion have not been demonstrated in full-scale wood-fired boilers. Overfire air ports are claimed to lower NO_x emissions from wood-fired stoker and fluidized bed combustion units (USEPA 2001), although evidence that such installations exist is lacking. Tests conducted by Philo, Chapman, and Mirolli (1989) on a tangential wood-fired boiler (550 KPPH) with 0 and 20% OFA at a constant 30-35% excess air and over boiler loads ranging from 55 to 100% of rated capacity, showed NO_x emissions actually increased (from 20 to 30%) with the 20% OFA operation at all three boiler loads evaluated. The authors stated, however, that this phenomenon was likely unit-specific, and that increasing OFA mass flow should typically lead to reduced NO_x emissions as in situations with fossil fuel firing.

Certain biomass fuels such as sander dust from operations using urea formaldehyde (UF) resins or agricultural waste such as rice husks and wheat straw can contain high nitrogen levels ranging from 0.5 to 2.5% by weight. When combusted, these can lead to high levels of NO_x. Webster and

Drennan (2003) discuss their experience with using air staging in reducing NO_x emissions by over 50% when burning sander dust fuels in two boilers, one a "packaged" boiler at a medium density fiberboard plant, and the second a bark grate boiler with sander dust suspension-fired over the grate. A Dual Air Zone (DAZ) gas burner with an annular scroll to introduce the sander dust with sub-stoichiometric air flow through the burner was used in both cases. In the packaged boiler, a separate system of adjustable direction air ports in the boiler front wall was used to introduce the secondary combustion air, and NO_x emissions were reduced by 43 to 51%. Tests in the bark grate boiler were reportedly under way. This boiler was to be equipped with overfire air ports above the suspension-fired sander dust burners, and computational fluid dynamics modeling techniques were to be used to bring about an NO_x reduction of over 70% compared to unstaged combustion of the sander dust.

Gas reburning techniques have been demonstrated for a short duration in one wood-fired stoker boiler that also burned small amounts of waste treatment plant residuals, with NO_x reductions of 40 to 50% from baseline (untuned boiler) reported (Schrecengost et al. 2002). However, this reburn technology would require a 5 to 25% natural gas input. Other combustion modification techniques such as FGR would not be effective in wood combustion since FGR reduces formation of thermal NO_x by reducing peak temperatures, and most of the NO_x generated during wood combustion is from the "fuel NO_x" pathway. FGR may also reduce the availability of O_2 in the combustion zone, but the impact of this on NO_x generation during wood combustion has not been demonstrated.

As for fossil fuels, post-combustion control options for wood-fired boilers include SNCR and SCR. Other emerging technologies (see Section 6.0) such as catalytic or low temperature oxidation followed by scrubbing have not been applied on a full scale to FPI boilers at the present time.

SNCR has been applied to several base-loaded wood and combination wood-fired boilers (www.fueltechnv.com). However, its efficacy on stoker wood-fired boilers, especially with changing loads, has not been adequately demonstrated, except when used as a polishing step. Early use of ammonia injection in the case of one pulp mill wood-fired boiler met with significant problems and had to be abandoned (Abrams 1998). While the manufacturer had guaranteed an NO_x emission rate of 0.042 $lb/10^6$ Btu, the boiler was unable to meet this guarantee unless operated at less than half load. Even then, reducing NO_x to near permitted limits consumed considerably more ammonia than anticipated, leading to the formation of a visible ammonium chloride plume. A similar problem was encountered at a second FPI mill. The fluidized bed combustor at the mill fired various fuels (bark, gas, recycled paperboard, and sawdust, $\approx 300 \times 10^6$ Btu/hr), and was equipped with a urea injection system (SNCR), which reduced NO_x emissions under varying loads from about 250 lb/hr (uncontrolled) to between 25 and 40 lb/hr (84 to 90% removal) (NCASI File Information). However, a single measurement in the stack showed nearly 75 lb/hr of ammonia were being emitted, suggesting that nearly half the urea (on a molar basis) injected was being emitted as ammonia in order to bring about this level of NO_x reduction.

The use of SNCR technology on most base-loaded wood-fired boilers could be considered a proven technology, although the suitability of the unique fuel mix, boiler design, and boiler operation (including ductwork, flue gas temperature profiles and desired residence times, flue gas chemistry, etc.) inherent in each boiler should be evaluated on a case-by-case basis. Typical maximum levels of NO_x emissions control achievable are in the range of 30 to 60%. The use of SNCR on stoker type wood-fired boilers that have significant load swings has not been demonstrated. Excessive ammonia slip (ammonia is an air toxic in many states) is a primary concern when adequate dispersion of the SNCR chemical is not achieved in the boiler ductwork within the range of residence times available and temperatures needed for the NO_x reduction reactions to go to completion. Also, when dry particulate matter (PM) emission control is utilized (such as an ESP), problems with plume opacity from ammonium chloride in the stack gases could arise, especially for combination boilers. For boilers which produce high levels of SO_2/SO_3 (combination wood-fired boilers), problems associated with ammonium sulfate/bisulfate deposition on heat transfer surfaces could also arise.

The impact of interference from higher CO levels present in many wood-fired boilers (compared to fossil fuel-fired boilers) with the SNCR chemical is currently unknown. Also, the possibility of appreciable SNCR chemical being absorbed on to the ash matrix in a wood-fired boiler should be examined. The extent and fate of ammonia in precipitated ash from boilers with dry PM control or scrubber purge streams for boilers with wet PM control also need to be adequately investigated.

The use of SCR on wood-fired boilers in the forest products industry has not been demonstrated. The use of SCR technology on wood- or combination wood-fired boilers would be considered technically infeasible based upon the fact that post-particulate removal flue gas temperatures are typically significantly lower than those desired for this application (450 to 750°F). Many wood- and combination wood-fired boilers are equipped with wet scrubbers for particulate emission (PM) control. Reheating the scrubbed flue gases from these boilers (typical temperatures from 150 to 220°F) to bring them within the desired temperature window would involve a significant energy penalty. For pre-particulate removal flue gas application, catalyst deactivation from high particulate loading would be a serious concern, in addition to the impact of fluctuating loads on flue gas temperatures. Deactivation and/or poisoning could result from the size and density of fly ash particulate, and from their unique chemical and physical nature. Water soluble alkali (such as Mg, Na) in particulate-laden gas streams have been known to poison SCR catalysts (USEPA 1999). Space considerations for installing a catalyst section in an existing boiler's ductwork are also important.

In response to a request for information from a consultant and one of their FPI clients, Fuel Tech N. V. (www.fueltechnv.com) reviewed the possibility of applying SCR to a certain circulating fluidized bed combination wood-fired boiler (T. Brown, personal communication, June 26, 2002). They found that the only "wood-fired" boiler SCR application in service in the U.S. was located at a woodworking facility in Archbold, Ohio. Fuel Tech contacted this facility (Sauder Corporation) to learn more about their process and the design of the SCR system. Although specific discussions on the fuel makeup were not held, it was assumed the wood fuel was sawdust and relatively high quality wood scraps from the furniture-making process. It was learned this SCR was located downstream of a mechanical collector and electrostatic precipitator, operating in flue gas temperatures ranging from 550°F to 650°F. The only problem reported at this installation was minor catalyst blinding due to the deposition of fine particulate that escaped the PM collection devices. It was learned the operating temperature for this SCR system allowed the use of conventional catalysts designed to accommodate high dust applications. For these catalysts, the catalyst openings through which the flue gas flows are sized to provide proper surface area contact and sufficient flue gas velocity to minimize fouling. Low temperature catalyst designs are considerably different and would not be recommended for use on any high dust application.

Based on this description of the air pollution control system configuration and the operating conditions for this particular wood-fired boiler, it is important to identify several specific differences between this installation and those that operate in the FPI. First, due to the requirement to provide hot air to burn all but the driest of wood fuels, wood-fired boilers are usually equipped with air preheaters (Stultz and Kitto 1992). Thus, even when dry particulate control devices like an ESP are utilized, the flue gas exits such control devices at temperatures in the 350°F to 450°F range. Consequently, the installation of an SCR catalyst section after an ESP to treat gases in the range of 550°F and 650°F is not amenable for adaptation to such boilers without, of course, incurring a severe energy penalty. Second, a significant portion of the FPI's wood-fired boilers are controlled for PM emissions by multiclones and wet scrubbers. The PM emissions from these would therefore be higher than the Sauder situation. Third, it is unclear how the Sauder SCR system would have worked under a fluctuating boiler load characteristic of many FPI boilers. Finally, sawdust fired in the Sauder boiler is a low moisture fuel, and the particulate matter present in the flue gases from its combustion is likely to be of different composition than when bark or hog fuel (typically much higher moisture) is burned.

In conclusion, the use of SCR technology has clearly not been demonstrated for industrial wood, biomass or combination fuel-fired boilers in the forest products industry, and the issues pertaining to severe energy penalties and space and logistical limitations, and potential catalyst poisoning from soluble alkali metals need to be addressed. The feasibility of achieving high levels of NO_x removal (such as >60%) using SNCR technologies on wood-fired boilers is uncertain due to several limitations, including the key one of installing optimally placed injection points for the SNCR chemical in swinging load situations and dealing with potentially excessive NH_3 slip and plume opacity problems. Combustion modifications (with perhaps the exception of gas reburning where gas is available) are generally not effective for biomass-fired boilers since most of the NO_x is generated by the fuel NO_x pathway. Emerging post-combustion technologies and in-furnace technologies such as gas reburning are in the early stages of demonstration.

4.1.5 *Combination Wood-Fossil Fuel*

As previously mentioned, nearly 40% of the wood-fired boilers in the pulp and paper industry are capable of firing coal. The Electric Power Research Institute (EPRI), with co-funding from the Department of Energy (DOE), and with utility cooperation and cost sharing, tested co-firing of biomass in ten coal-fired utility boilers (Hughes 1998). NO_x emissions recorded at three of these boilers are summarized in Table 4.1. The biofuels fired included sawdust, dry shavings, and wood chips. Typically, the trend observed was lower NO_x emissions with increased levels of biomass co-firing, at least up to the point where about 10% of the heat was supplied by the biomass. The recorded range of NO_x reductions was typically between 0 and 15-20%. The authors conclude NO_x reductions can be the result of several factors, including reduced total fuel nitrogen, lower firing temperatures because of increased fuel moisture, and increased staging of the combustion process due to early volatiles burnout in the biomass fraction. Preliminary results show that the co-firing of up to 7% biomass, on a heat-input basis, with crushed or pulverized coal can lower NO_x emissions by as much as 15% depending on the firing configuration. These tests did not explore optimizing the firing configuration for biomass to maximize the NO_x control potential for this renewable fuel. Some tests did not show any NO_x reduction at all.

In an attempt to explain the outcomes of co-firing biomass in pulverized coal boilers, particularly the potential for simultaneous reduction of NO_x, Tillman (2003) looked into the differences in combustion characteristics between various biomass fuels and coals using a drop tube reactor (DTR). An analysis of the NO_x reduction data obtained from several EPRI demonstrations of the co-firing of biomass with coal showed that one could expect slightly above 1% NO_x reduction from baseline levels for every 1% co-firing percentage of biomass (Btu basis). The DTR laboratory results with sawdust, urban wood waste, fresh switchgrass, and weathered switchgrass for biomass fuels and two reference coals led to the following conclusions: a) fuel reactivity is a key to NO_x control using staged combustion; b) biomass fuels, in general, are highly reactive, although weathering reduces nitrogen reactivity in switchgrass; c) the relative reactivity of biomass and various coals can be used as a technique to evaluate potential in NO_x management; and d) the DTR technique for analyzing fuels has significant benefits in evaluating initial combustion processes applied to NO_x management.

Table 4.1 NO_x Emissions Results with Wood Waste Co-Firing with Coal (Hughes 1998)

Site	Biofuel	Baseline NO_x lb/MMBtu	Percent Co-Fire (mass basis)	Percent Co-Fire (heat basis)	NO_x Reductions (percent)
GPU Seward	Wood	0.87 to 0.95	3.4 to 6.4	1.5 to 2.8	0 to 11
	(FGS, DSS		8.2 to 9.4	3.1 to 4.3	2.3 to 13
	and OS)[a]		11.9 to 13.8	4.3 to 8.1	3.4 to 14
			16.1 to 17.9	7.6 to 10.3	5.7 to 18
TVA Allen	Wood	2.0	8.5 to 10	4.5	0 to 11.6
	(sawdust)	with E. Coal	20	9.0	25
TVA Allen	Wood	1.5	4.3	1.9	-1.3 to 7.3
	(sawdust &	with W. Coal	10	4.7	-8.7 to 14
	woodchips)		15	6.9	-2.7
NIPSCO Mich. City	Wood	1.05 to 1.28 (1.17 avg)	10	6.5	0 to 20 (9.5 avg)

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[a] FGS = Fresh Green Sawdust; DSS = Dry Shavings and Sawdust; OS = Old Sawdust

4.2 Gas Turbines

There are a variety of combustion modification techniques and add-on control technologies to reduce NO_x emissions from combustion turbines (CT). These include a) wet controls, b) dry low NO_x (DLN) combustion controls, c) catalytic combustors, and d) selective catalytic reduction (SCR). Wet controls involve injecting water or steam into the flame of a CT to provide a sink that limits thermal NO_x. Suppression of NO_x formation from 70 to 90% is believed feasible (USEPA 1996). Combustion controls consist of either the Lean Combustion or Lean Premixed System, which have been deployed on new CT units in recent years (USEPA 1996). These systems are generally used as alternatives to wet systems. One of the difficulties with lean premixed systems is maintaining flame stability in the narrow flame temperature range between high NO_x production and lean flame extinction (Peltier 2003). Catalytic combustion promises to be an alternative for DLN technologies. Catalytic combustors burn lean fuel-air mixtures to achieve sub-5 ppm NO_x. The maximum combustor exit temperature is 2,460°F or lower, which is well below the NO_x formation temperature (Peltier 2003). SCR can be applied to CTs in a manner similar to that for steam boilers. Distillate oil is occasionally used in place of natural gas in gas turbines.

4.3 Fluidized Bed Combustors

Pulp mill boilers capable of firing coal or wood often have the option to burn other solid fuels such as tire chips, wastewater treatment plant residuals (sludge), rejected material from processing of old corrugated containers (OCC rejects), non-recyclable paper pellets, etc. The amount of these materials that can be burned in traditional spreader-stoker type boilers is relatively small, and co-firing them with wood and/or coal has only minimal effects on the emissions. Fluidized bed boilers, on the other hand, can accommodate much larger percentages of alternative solid fuels. In general, coal-fired fluidized bed combustors (FBCs) are capable of achieving relatively low levels of NO_x, SO_2, CO, and particulates (Makanski 1991). The combustor operating temperatures are very low, in the 1500° to 1600°F range, thus limiting the formation of NO_x. Nearly all circulating fluid bed (CFB) designs employ staging to minimize NO_x emissions. Post-combustion NO_x control using the SCR or SNCR technologies is feasible, but SCR in particular has only been demonstrated on large utility FBCs.

One southeastern kraft pulp mill operates a bubbling fluidized bed boiler (BFB) equipped with an SNCR system. This 820 MMBtu/hr BFB burns various combinations of wood, waste treatment plant residuals, and tire-derived fuel and uses the NOxOUT process to reduce NO_x levels by about 40% from a baseline level of about 0.35 lb/10^6 Btu (NCASI file information). The NO_xOUT process was originally designed to reduce NO_x emissions by about 62%. A second southeastern mill operates a CFB boiler that burns coal, wood residue, non-recyclable and pulper rejects, and some synfuel gas (175 MMBtu/hr) in varying blends and has been equipped with a urea-based SNCR system since 1996. The SNCR system is designed to achieve a 50% NO_x reduction. However, the boiler is able to achieve its permit limit of 0.3 lb/MMBtu without the use of SNCR. The removal efficiency has never been guaranteed since the fuel blend varies all the time. A third (northwestern) pulp mill also operates a CFB boiler (165 MMBtu/hr) that burns wood residues, waste treatment plant (WTP) residuals and some gas, and since 1996 has also been equipped with an SNCR system designed to reduce NO_x by up to 60%. The WTP residuals at this mill contain high levels of nitrogen, resulting in higher levels of NO_x (uncontrolled) compared to wood alone.

Leckner and Karlsson (1993) studied emissions of NO, N_2O, SO_2 and CO from fluidized bed combustion of mixtures of wood and coal in a 12 MW research circulating fluidized bed (CFB) boiler. Bituminous coal (1.5% N) was co-fired with sawdust (0.10% N) or fir chips (0.15% N) in amounts ranging from 0 to 100% coal. In spite of the much lower N content, 100% wood firing led to higher NO emissions than did 100% coal firing. Reduction of NO by char in the bed and ten times higher char concentrations in the bed during 100% coal burning compared to 100% wood burning were believed to explain this difference. Small additions of coal to wood initially yielded a higher NO emission than even 100% wood. The authors explained that at low coal contents, since the amount of char in the bed was small, the reduction of NO formed during coal burning by char was small and higher fractions of the coal N were converting to NO. NO reduction by char from coal burning increased with higher levels of coal burning, leading ultimately to lower NO emissions from 100% coal burning than from 100% wood burning. Emissions of N_2O were primarily from coal burning (negligible from wood burning).

One emission from circulating and bubbling bed combustors burning coal that could potentially be of concern is the greenhouse gas nitrous oxide (N_2O). In CFB combustors, the N_2O levels could be as much as 70% of the corresponding NO_x ($NO+NO_2$) levels (IPCC 1997). The formation of N_2O depends on the combustion temperature, with the highest N_2O emissions occurring at a temperature of about 1,000°K (1,340°F). For combustion temperatures below 800°K or above 1,200°K, the N_2O emissions are negligible (IPCC 1997). In pulverized coal and stoker-fired boilers, higher flame and post-flame temperatures in the presence of gas phase radicals preclude the formation of N_2O (Makanski 1991).

5.0 TECHNOLOGICAL ADVANCES IN NO_X CONTROL FOR BOILERS

This section provides brief summaries of recent reports and reviews published in the literature on the current state of the art for NO_x emissions control, especially as applied to industrial boilers. Although much of the information pertains to utility boilers, some of it can be useful in understanding NO_x emissions control from industrial boilers.

5.1 Swanekamp (2002a)

In a special report titled *Emissions-Control Technologies Continue to Clear the Air*, Swanekamp described advances in combustion and post-combustion technologies that reduced stack emissions from utility boilers and gas turbines. He made the following observations relevant to NO_x emissions control:

- Combustion modification is generally the lowest-cost option for NO_x control.
    - At one utility, the John Zink Co. applied its COOLflow modeling technology to design baffles and turning vanes in the windbox and ductwork systems to correct air flow distribution problems; this in turn optimized combustion and also enabled existing (unused) OFA ports to be returned to service, resulting in a 22% reduction in NO_x emissions.
    - The Rotating Opposed Fire Air (ROFA) system by Mobotec USA improved combustion by creating upper-boiler turbulence with high-velocity air injection through asymmetrically located nozzles in the boiler walls. The system was expected to reduce NO_x emissions at two utilities by 50 to 75% using no chemicals or catalysts.
- LNB with OFA is the most popular combustion modification and is capable of achieving NO_x reductions of up to 70% with gas and oil fuels.
- Sophisticated software known as a "process-optimization package" uses techniques like neural networks, Bayesian analysis, and internal heuristics to monitor critical process parameters, determine optimum setpoints and communicate them to control devices, and continuously reconfigure the control system based upon the software models. The software is used by many fossil-fueled utilities to limit NO_x emissions. The use resulted in a 20% reduction in NO_x at one utility.
- There are limitations to combustion modifications such as LNBs and optimization software.
    - LNBs are best applied to wall-fired units, not cyclones.
    - LNBs can cause performance problems, such as carbon loss and tube-wall wastage.
    - Most importantly, even in "layered" applications, they cannot meet levels dictated by the NO_x SIP Call.
- SCR is the only commercially viable alternative for high levels of NO_x reduction.
- Ammonia slip requirements are getting stricter in many states – typically 5 ppm in California; 2 ppm in Massachusetts; some NE states are pushing for "zero" slip.

5.2 Swanekamp (2002b)

In a brief excerpt titled "Connectiv plant cuts NO_x emissions without SCR," Swanekamp described RJM Corporation's "layered approach" to achieve 90% NO_x emissions reduction without an SCR at 60% of the cost of an SCR retrofit as applied to a 480 MW coal/oil-fired boiler in Beesley's Point, New Jersey. The first four layers included:

- burner modifications
- installation of overfire air ports

- NO_x tempering, which injects micronized water droplets into high-NO_x production zones, and
- SNCR, which injects a urea-based reagent into the lean-fuel zone above the furnace.

The fifth layer, dubbed “absolute compliance” or “RJM-AC,” involved injection of an amine reagent in the primary combustion zone. RJM Corporation also described a “combustion tempering” technique applied to a natural gas-fired cyclone boiler, “burner optimizations” applied to three coal-fired front-fired utility boilers rated at 50MW each, and a rich reagent (amine-based) injection system followed by OFA applied to a 138 MW cyclone coal-fired boiler, all three in conjunction with SNCR systems, to achieve nearly 60%, over 70% and nearly 80% NO_x reduction, respectively (http://www.rjm.com/html/techinfo.htm).

5.3 Swanekamp and Ellison (2001)

The use of ammonia- or urea-based additive treatments in de-NO_x processes, either upstream or downstream of the boiler economizer, presented substantial problems. Technological advances to address these problems, including supplemental additive treatment techniques, were discussed in two conferences and summarized by Swanekamp and Ellison.

- Lime addition in a furnace can negate high SO_3 concentrations and lead to sludge buildup in the air preheater.
- Lime addition can also tie up catalyst poisoning arsenic in coal.
- Additives can counteract high lime content in some PRB coals, which can foul SCR catalysts.
- Replacing tubular air heaters with Ljungstrom-type helps catalyst plugging problems.
- Replacing soot blowers by on-line acoustic horns produces favorable results.

Additionally, the authors reported other technological advances including the following:

- a Fuel Lean Gas Reburn (FLGR) system (that used natural gas injection to replace 3-10% of heat input from coal) which can be integrated with SNCR
- a conversion system of urea, a stable non-volatile material that is safer to transport, store, and handle, to a gaseous mixture of ammonia on-site as and when needed for use in SCR systems.

5.4 NESCAUM (2001)

In a 2001 report entitled *Power Companies’ Efforts to Comply with the* NO_x *SIP Call and Section 126, Progress Report*” the Northeast States for Coordinated Air Use Management (NESCAUM) made the following key points relative to NO_x control:

- The NO_x SIP Call region’s total SCR commitment was at least 115 units, representing over 66,000 MWs of capacity.
- 0.15 lb/MMBtu represented an 85% reduction from uncontrolled NO_x for most large coal-fired power plants; hence, SCR was the most suitable candidate for NO_x control.
- Other emerging technologies in the mix included:

- a combustion technology called ThermaloNO$_x$ that had been applied at American Electric Power's 375 MW Conesville facility (expected to achieve 80 to 90% NO$_x$ reduction)
- a combustion improvement technology called Rotating Overfire Air used at Carolina Power & Light's Cape Fear facility, and
- a reburn technology supplied by General Electric to the Southern Company's Scherer plant (50 to 70% reduction expected).

5.5 NESCAUM (2000)

In a 2000 report entitled *Status Report on NO$_x$ Control for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines – Technologies & Cost Effectiveness - Executive Summary*, NESCAUM evaluated various control technologies that had been commercially applied to four major source categories, including industrial boilers in the northeastern states and also their cost-effectiveness in reducing emissions of oxides of nitrogen. Case studies were taken up for actual installations of NO$_x$ reduction technologies on many sources, and detailed write-ups prepared in cooperation with the users of the technologies. The users provided all the information and approved the written descriptions of the case studies. Thus, the case studies represented the user's view of the performance, reliability, and cost of technologies (NESCAUM 2000). Relative to industrial boilers, the report noted the following significant findings:

- LNB, OFA, SCR, SNCR, and reburn technology have been used for NO$_x$ reduction.
- Decisions to use OFA should be made on a case-by-case basis.
- In year 2000, for pulverized coal boilers, a 30% NO$_x$ reduction could be achieved with LNB at a cost of <\$2,000/ton.
- LNBs were capable of controlling a majority of gas-fired industrial boilers to NO$_x$ levels below 0.15 lb/MMBtu.
- LNBs on boilers firing No. 6 oil achieved median NO$_x$ levels of 0.35 lb/MMBtu.
- SIP Call-dictated annual NO$_x$ reductions with LNB for oil & gas-fired industrial boilers can be achieved at <\$2,000/ton for moderate to high capacity factor (65 to 85%) units.
- SNCR was well suited for industrial boilers, achieving on average over 50% NO$_x$ reduction.
- SCR had seen only limited use in the U.S. on boilers firing solid fuel, but there was no technical reason to prevent its use on such boilers.
- Gas reburn technologies operating on some industrial boilers in the U.S. were providing NO$_x$ reductions of about 50%.

6.0 EMERGING TECHNOLOGIES FOR INDUSTRIAL BOILER NO$_X$ CONTROL

This section reviews some of the emerging NO$_x$ control technologies presented in the literature that may be applicable to industrial boilers. However, it should be emphasized that most (if not all) of these technologies are currently under development or in the "full-scale" evaluation stage. They involve both combustion modifications and post-combustion flue gas NO$_x$ emissions control.

6.1 Methane de-NOX Reburn Technology

Reburning involves the staged addition of fuel into two combustion zones: a) the primary combustion zone where the primary fuel is fired; and b) the reburn zone where additional fuel (the reburn fuel) is added to create a reducing (oxygen deficient) condition to convert the NO_x produced in the primary zone to molecular nitrogen (N_2) and water. In the reducing zone, the reburn fuel molecules break down to hydrocarbon fragments (CH, CH_2, etc.) that react with NO_x. Above the reburn zone is a burnout zone where OFA is added to complete the combustion.

Schrecengost et al. (2002) provided an overview of a gas reburn technology (Methane de-NOX) using 5 to 25% natural gas heat input for combustion improvement and 50 to 70% NO_x reduction in coal-, biomass-, and MSW-fired stoker boilers. The process features injection of gas near the grate with recirculated flue gas and injection of overfire air at a higher furnace elevation to burn out the combustibles. The oxygen-deficient atmosphere above the grate is expected to retard NO_x formation. More recently, the Methane de-NOX technology (MdN) is being applied to kraft pulp mill stoker boilers by utilizing the VOC content of non-condensible gases (NCGs) to partially replace the natural gas (by up to 25%). This technology has been tested for over a year at one pulp mill boiler, and is being tested at several boilers within one FPI company. The MdN technology has also been applied to two MSW plants and a coal-fired utility. The authors claimed the following energy and environmental benefits when applying this technology to pulp and paper industry boilers:

- reduced operating costs and air emissions through advanced combustion with strategic use of natural gas
    - ➢ increased utilization of wood residues
    - ➢ improved boiler operability, reliability, and efficiency
    - ➢ improved boiler environmental performance
- increased effective, efficient, and reliable self-generated power capacity
- cost-effective and efficient destruction/utilization of NCGs.

6.2 Low Temperature Oxidation

Low temperature oxidation (LTO) is an NO_x removal system that uses ozone, injected into the flue gas stream, to oxidize insoluble NO_x to soluble oxidized compounds. Ozone is produced on site and on demand by passing oxygen through a conventional industrial ozone generator.

The BOC Group commercialized this technology under the trade name LoTOx. Barasso and Donovan (2002a, 2002b) presented the following key points relevant to the LTO technology for NO_x control.

- NO and NO_2 in a gas stream were oxidized to highly soluble N_2O_5 and HNO_3 by injecting ozone.
- A particulate and/or SO_2 scrubber was used to scrub out the oxidized compounds.
- Ozone was produced in response to the amount of NO_x present in the flue gas.
- At the design retention time, ozone reacted selectively with NO_x and not with SO_x and CO.
- LTO operated optimally below 300°F.
- Performance was unaffected by “dirty” streams.

Tests conducted in 2002 on a slip stream from a pulp and paper industry bubbling fluidized bed boiler burning deink sludge, bark and TDF were reported to be successful in reducing NO_x emissions by over 90% (http://www.boc.com/news/article_detail.cfm?ID=334&bSegment=0). A 25 MW coal-fired power plant at the Medical College of Ohio (MCO) is the only full-scale installation of LTO technology to date. It has been operating since October 2001. The MCO system involves a semi-dry rapid absorption process for SO_x scrubbing (using lime slurry) and a bag house particulate control technology, followed by the LTO system for NO_x removal. The LTO system consists of a reactor (72-inch diameter, one pass with 1.5 sec residence time), followed by a wet absorber and a wet stack, associated oxygen supply, an ozone generator, and a cooling water system. A six-month testing phase was planned in late 2001 to determine performance of the LTO system at a 45,000 lb/hr boiler steam load. Early operating results indicated 85 to 90% NO_x removal from 50 to 70 ppm baseline levels. A 1,000 acfm slip stream at a 500 MW coal-fired boiler and a slip stream at a 400 MM Btu/hr bubbling fluidized boiler burning wood residues, deink residuals, tire-derived fuel, and natural gas at a deinking facility have also been reported to be tested successfully with over 90% NO_x removal. Cost estimates are not available for comparison, although a cost analysis carried out using this technology on a 200 MW coal-fired power plant with an existing FGD scrubber showed that fixed costs were 50 to 55% of total annual cost, and operating costs (largely the power for ozone generation and oxygen) were 45 to 50%, with a cost-effectiveness estimated at about $1,696 per ton of NO_x removed from the baseline (0.4 lb/MM Btu).

6.3 Induced Flue Gas Recirculation Technology

For modified flue gas recirculation technology (Broske 1998), a duct is added between the economizer outlet (or air preheater outlet) duct and the FD fan, thus eliminating the need for a separate FGR fan, where the boiler flue gas is recirculated to the combustion zone by induced flow through the FD fan(s) and a flue gas flow rate of 0 to 20% is controlled (manually or automatically) over the load range.

The following advantages were claimed for this technology.

- 40 to 50% NO_x reduction at a low cost ($0.25 to $1.00/kW installed cost, about 30% of cost of LNB or FGR)
- easy to retrofit
- applicable to various boiler firing systems

The following disadvantages were also noted.

- may limit the boiler load (without modifications)
- involved a heat penalty (0.3 to 0.5%)
- reduced the rate of load change during transitions
- affected steam temperature (spray capacity)

6.4 The Pahlman Process

Enviroscrub Technologies Corporation, a Minneapolis, Minnesota company, provided some information about a unique (but secretive) NO_x scrubbing process at their website (www.enviroscrub.com) that included the following:

- a one step, dry scrubbing process using a fine black powder dubbed Pahlmanite
- slip streams tested using this technology at the Huntsville Power station, Huntsville, Illinois, the Boswell Energy Center (Minnesota Power), Cohasset, Minnesota and Potlatch Corporation's Brainerd, Minnesota coal-fired boiler (mill since shut down)
- claimed between 75 and 96% NO_x removal
- compounds of sulfur (sulfates) and nitrogen (nitrates) formed when Pahlmanite is regenerated for reuse could be resold for chemical or as fertilizer

6.5 Other Emerging Technologies

One emerging technology involves the injection of elemental phosphorus as an oxidant to convert NO to NO_2 which is then removed in a wet scrubber. The first full-scale application of Thermal Energy's THERMALONOx technology on a power plant has been undergoing a commercial demonstration on a high sulfur coal-fired utility boiler in Ohio. Initial results of this demonstration at American Electric Power's (AEP) Conesville plant suggest a need for additional research. AEP stated that despite the promising nature of the technology, the data from the demonstration indicate the system did not appreciably reduce nitrogen oxide emission levels from the plant's 375-megawatt generating unit (http://www.aep.com/environmental/performance). The system was expected to remove as much as 75% of the NO_x emissions from the exhaust gases of utility power plants and industrial boilers when used in combination with a flue-gas desulfurization system.

The Electric Power Research Institute (EPRI) stated in December 2002 it was involved with several emerging post-combustion NO_x control technologies that were principally designed for utility coal-fired boilers (http://www.epri.com/corporate/ productsservices/project_opps/gen/1007605.pdf). Some of these technologies may have application to industrial boilers. The projects included:

- boosted overfire air + SNCR (urea reagent)
- ecotube high pressure OFA system + ammonia injection
- Mobotec ROTAMIX^{TM} (ammonia injection)
- SNCR Trim (single level of injectors)
- Selective Auto-Catalytic Reduction (SACR)
- rich reagent injection

Durr Environmental (http://www.durrenvironmental.com/NOXCS.asp) offered a Zero Ammonia Technology (ZAT) that did not require the injection of ammonia or urea. ZAT is a catalytic-based system that converts all of the NO_x into NO_2 (i.e., it oxidizes the NO) and adsorbs the NO_2 onto the catalyst. Portions of the catalyst are isolated from the exhaust stream, and the adsorbed NO_2 is reduced to N_2 using diluted hydrogen, or some sort of hydrogen reagent gas, and desorbed from the catalyst.

The National Energy Technology Laboratory (NETL) stated that it was managing several NO_x control technology R&D projects ranging from laboratory studies to modeling to full-scale demonstration. The technologies being addressed included ultra low NO_x burners, advanced reburning, selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR), METHANE de-NOx, and oxygen-enhanced combustion. The project summaries may be found at http://www.netl.doe.gov/ publications/proceedings/02/ubc/lanisummary.pdf.

6.5.1 *Ultra Low NO_x Integrated Systems for NOx Emission Control*

Alstom Power reported developing an ultra low NO_x integrated system for coal-fired power plants that will achieve furnace outlet emission levels at or below 0.15 lb/MMBtu. The reduced NO_x emissions will be obtained without increasing the level of unburned carbon (UBC) in the fly ash through advances in control systems, combustion process modifications, and postcombustion carbon burnout technology. The target market would be tangentially fired (T-fired) coal boilers, which represent about 40% of the boilers currently listed in the State Implementation Plan (SIP) Call region.

6.5.2 *NO_x Control Options and Integration for U.S. Coal-Fired Boilers*

Reaction Engineering International has reported optimizing the performance of the combined application of low NO_x firing systems (LNFS) and post-combustion controls. The project will assess real-time monitoring equipment to evaluate waterwall wastage, soot formation, and burner stoichiometry. In addition, the impact of various coals on SCR catalyst activity will be investigated along with novel UBC/fly ash separation processes. The primary target of the research would be cyclone boilers, which represent about 20% of the U.S. generating capacity.

6.5.3 *Cost-Effective Control of NO_x with Integrated Ultra Low NOx-PC Burners and SNCR*

In another advanced low NO_x burner project, McDermott Technology and Fuel Tech have reported teaming up to develop an integrated system comprised of ultra LNBs, coupled with SNCR. The overall goal of this project is to develop a cost-effective control system capable of achieving NO_x levels below 0.15 lb/MMBtu for a wide range of coals. The primary market for the ultra LNB/SNCR technology would be front- and opposed-wall-fired boilers within the NOx SIP Call region, with cell-fired, roof-fired, and arch-fired boilers also among the candidates.

6.5.4 *METHANE de-NOx for Utility Boilers*

The Gas Technology Institute (GTI; formerly the Institute of Gas Technology and Gas Research Institute) has reported developing a pulverized-coal combustion reburn system. The technology integrates natural gas-fired coal preheating, LNBs with internal combustion staging, and additional natural gas injection with overfire air. Preheating the coal promotes the conversion of fuel-bound nitrogen to molecular nitrogen rather than to NO_x. GTI estimates the market for the technology would include more than 21,000 burners (over 260,600 MW) in the 37 eastern states encompassing wall-fired (wet- and dry-bottom), T-fired, roof-fired, and cell burners.

6.5.5 *Oxygen-Enhanced Combustion for NO_x Control*

Praxair has reported developing oxygen-enhanced combustion and oxygen-enhanced reburning technologies for controlling NO_x. Oxygen-enhanced combustion can be used to control both thermal and fuel NO_x. The key to this project is the use of controlled conditions to take advantage of the combustion benefits of oxy-fuel firing to reduce NO_x emissions below 0.15 lb/MMBtu.

7.0 TECHNICAL LIMITATIONS OF APPLYING AVAILABLE NO_X CONTROL TECHNOLOGIES TO FPI BOILERS

Much of the operating experience gained on fossil fuel-fired boiler NO_x emissions control has involved utility boilers. A few gas and/or oil-fired FPI boilers have employed combustion modification NO_x reduction techniques such as LNB, OFA and FGR. A few have even installed SNCR for post-combustion NO_x emissions control. The SNCRs have typically been installed on base-loaded boilers or for marginal NO_x removal purposes. None has SCR in place.

In November of 1998, the American Forest and Paper Association (AF&PA), along with several other organizations including the Council of Industrial Boilers (CIBO), submitted a petition to the DC Circuit Court challenging the revised Subpart Db standards of performance for NO_x applicable to fossil-fuel fired steam-generating units ("boilers") promulgated by EPA on September 16, 1998. The petition claimed EPA did not consider adequately the feasibility of installing SCR on coal-fired industrial boilers (or coal/wood and coal/oil boilers) which have different characteristics than utility boilers such as swinging loads. It highlighted several characteristics pertinent to pulp and paper industry boilers that differentiate them from utility boilers, thereby calling the applicability of a uniform technology-based NO_x standard into question. EPA responded to this petition in a July 30, 1999 legal brief, arguing that it should be denied (USEPA 1999). Highlights of the AF&PA petition, EPA's response, and an evaluation of EPA's response can be found in Appendix A.

Appendix B summarizes the public comments relative to FPI boilers that were submitted to EPA in response to the July 9, 1997 proposal to revise the NO_x emission limits in subparts Da and Db of 40 CFR Part 60. EPA's responses to these comments (USEPA 1998d) are also included in Appendix B.

The following sections summarize the technical limitations identified in selected industry and non-industry publications on the application of various NO_x control technologies to FPI boilers.

7.1 Applicability of Combustion Modifications

Industrial boilers typically operate with widely varying steam loads, with an estimated mean capacity utilization factor of 45 to 55% (CIBO 1993). Even recently installed cogeneration and independent-power facilities with higher utilization factors operate on dispatch schedules dictated by the utility purchasing the power (Jones 1994). NO_x reduction measures are particularly difficult to implement in small, low capacity facilities because a) residence time is limited and often inadequate for applying overfire air (OFA) without excessive loss of thermal efficiency or induced smoking; b) relatively small furnace dimensions limit combustion modifications that increase flame length and tend to cause the flame to impinge on tube walls' c) peak boiler efficiency and minimized NO_x emissions occur close to minimum flue-gas O_2 content, which is at the threshold of smoke or combustible-emissions formation; d) steam is used far more effectively in industrial applications than in conventional electric utility plants and, consequently, emission limits based on boiler heat input or volume of flue gas do not recognize such efficiency (Jones 1994).

The Council of Industrial Boiler Owners prepared an NO_x RACT (Reasonably Available Control Technologies) guidance document (CIBO 1993) which identified numerous reasons why uniform RACT rules for industrial boilers would be inappropriate.

- The industrial boiler population is diverse – no specific type is prevalent.
- There are very little hard NO_x emissions data for existing industrial systems.
- The variability of emissions from a unit, type system, or class of units, can be extreme.
- Projection of system trends is impractical; therefore, emissions may have to be considered on a unit-by-unit basis.
- Most industrial stoker fired units installed prior to 1987 were equipped with only one or two rows of overfire ports, and a maximum of 10 to 20% total air, an arrangement designed to optimize combustion efficiency, *not* to control NO_x emissions.
- Bottom-supported stoker units are virtually impossible to retrofit with a new overfire air arrangement.

- Inherent system variability required that a 30-day rolling average be the standard for industrial boilers.

In written comments to the Maine Department of Environmental Protection, Sonnichsen (1994) of CARNOT listed several reservations about applying utility NO_x control experience to industrial boilers.

- The greatest difference in utility and power boiler operations is the fluctuating steam demand characteristic of pulp and paper mill operations which requires that power boilers continuously adjust fuel firing rates and excess air levels. Even with the most sophisticated combustion controls, it is not practical or safe to maintain excess air continuously at minimum levels. Consequently, power boilers have characteristically and inherently higher NO_x emissions.
- Fuel biasing on an industrial boiler subject to rapid and excessive load swings could result in too rich or lean firing conditions, which can lead to flame stability problems and explosive conditions.
- Windbox flue gas recirculation (FGR) could be considered for use on oil-fired boilers. Its application, however, can be limited by (1) the windbox and boiler fans' capacities, (2) increased boiler bank tube wall erosion, and (3) the potential for severe damage from changes in convection heat transfer and boiler water circulation patterns.
- The application of low NO_x burners (LNB) is often limited by the longer flames produced as a consequence of improved air distribution control. While there is generally ample room for LNB flames in utility furnaces, their use on the smaller power boilers can result in flame impingement on furnace walls, leading to tube wall overheating and mechanical failure. Flame impingement can also result in premature flame quenching and increased soot and CO emissions.
- Unlike utilities which can specify the nitrogen content of their large oil purchases, most mills cannot do this.

Even within the family of industrial boilers there are considerable differences in the design of various types of boilers and therefore the applicability of certain NO_x control technologies. For example, considerable differences exist in the heat removal rates between a grate-fired boiler for wood residue or coal combustion and a packaged boiler for oil or gas combustion. The grate boiler is designed for staged combustion since a large amount of the combustion air is introduced above the grate fire. Also, the size of the grate furnace is two to three times greater than a similar packaged boiler. The net result is that there is more heat absorption in a grate-fired boiler resulting in lower thermal NO_x formation. Both air staging and flue gas recirculation, recommended NO_x control techniques for oil and gas combustion, when applied to packaged boilers will increase the burner flame length and require added furnace length to avoid flame impingement on the furnace walls.

7.2 Applicability of SNCR NO_x Control Technology

As previously mentioned, the use of the SNCR process in a packaged boiler would require access to a temperature window between about 1700 and 2000°F in which to inject the ammonia or urea. Controlling flue gas temperatures in the convective section of a package or even grate boiler over the entire range of operating loads the boiler is expected to experience will be very difficult to achieve. Boilers in the pulp and paper industry rarely operate under base loaded conditions. Consequently, the location of the desired temperature window is expected to change constantly. Accurate, instantaneous temperature measurement, as well as the ability to accurately adjust the location of the injection nozzle, would be necessary. Ammonia slip would be a recurring problem associated with the application of the SNCR process to industrial boilers with fluctuating loads.

7.3 Applicability of SCR NO_x Control Technology

An important factor restricting the use of the SCR process on most industrial boilers is the loss in energy efficiency that would result from the need to reheat the exhaust gases. Exhaust gases exiting the economizer sections of most FPI boilers are typically in the range of 250 to 400°F, while the desired temperature range for the SCR process is between 450 and 750°F. At part load, a boiler economizer bypass will probably be required, especially in high sulfur applications, as most boilers feature flue gas temperature at the economizer exit that is below the ammonium sulfate/bisulfate dew point (Cichanowicz 1999). Air heater surfaces must withstand corrosion from ammonium sulfates and bisulfates, be easily cleaned with conventional soot blowing, and survive corrosion-inducing water washing. SO_3 produced by the catalyst may condense on cooler surfaces, depending on the temperature, during both steady-state and non-steady-state operation. Higher levels of SO_2 to SO_3 conversion could cause accelerated corrosion or higher SO_3-induced plume opacity. Minimizing ammonia levels in the stack (typically <2 to 3 ppm) is required to avoid problems with disposing or marketing fly ash or scrubber byproduct contaminated by ammonia. The use of a particular catalyst puts restrictions on the fuel flexibility for a boiler. For example, purchasing coal with fly ash containing calcium oxide and arsenic outside the defined range absolves the catalyst supplier from responsibility for arsenic poisoning (Cichanowicz 1999).

8.0 PERMITTING INFORMATION

NO_x emission limits for boilers are often set on a case-by-case basis as part of an air quality permitting process. For new boilers, or existing boilers undergoing a major modification, obtaining a construction permit generally involves a determination of Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER). For existing boilers located in or near ozone non-attainment areas, NO_x emission limits may be based on facility-specific determinations of Reasonably Available Control Technology (RACT). EPA guidance indicates LAER limits should be the most stringent, followed by BACT and RACT limits.

Permitting decisions are usually made by states and reviewed by EPA regional offices. Information submitted by the permit applicant is considered in the decision-making process. Factors such as technical feasibility, cost-effectiveness, ambient air quality impact, and non-air quality impacts are evaluated on a facility-specific basis.

Appendix C contains information submitted to permitting agencies by forest products companies as part of their evaluation of alternative RACT, BACT, and/or LAER NO_x control options for boilers. Appendix D tabulates permitting decisions and NO_x emission limits in EPA's RACT/BACT/LAER Clearinghouse database for boilers at forest products industry manufacturing facilities for the period between 1992 and 2001.

9.0 NO_X EMISSIONS CONTROL COST ESTIMATES FOR INDUSTRIAL BOILERS

This section deals with costs for implementing NO_x emissions control on industrial boilers. Cost plays a critical role in making permitting decisions and in development of nationwide emission regulations such as the NSPS. First, EPA's summary analysis on NO_x control costs for fossil fuel-fired boilers presented during the promulgation of the revised Subpart Db NO_x emission standards for boilers is discussed. Cost estimates published by NESCAUM are then briefly summarized.

Finally, cost estimates and comments provided in permitting analyses of boiler NO_x control options performed by individual forest products industry companies are summarized.

9.1 EPA Estimates for New Industrial Fossil Fuel-Fired Boilers

In the background technical document for the revised Subpart Db NO_x emissions standards, EPA estimated control technology costs for installing various types of NO_x emissions control on new fossil fuel-fired industrial boilers (USEPA 1997). Annualized costs and incremental cost-effectiveness ranges from this document are reproduced for various model boilers in Tables 9.1 and 9.2, respectively. Table 9.1 shows the cost of installing combustion controls for NO_x emissions on industrial fossil fuel-fired boilers ranges from 0 to 2% of the net cost of generating steam in the boiler. It should be noted that the requisite combustion controls for fluidized bed combustors and spreader stokers burning coal and field-erected water tube boilers burning distillate oil or natural gas are already assumed to exist and thus represent the baseline for these boilers. When combustion controls are augmented by SNCR, the total cost rises to between 4% and 16% of the steam cost. Finally, when SCR is used along with combustion controls, the total cost increases appreciably to between 10% and 48% of the steam cost. Table 9.2 gives estimates for incremental cost-effectiveness in \$/ton NO_x removed. When applying SCR to industrial boilers after combustion controls have been implemented, the incremental cost-effectiveness estimates range from \$5,900 to \$49,800 per ton of NO_x removed. Incremental cost-effectiveness estimates for applying SNCR to boilers after combustion control implementation are also high, ranging from \$1,720 to \$32,140 per ton of NO_x removed. In the July 1997 *Federal Register* proposal ([*FR 62* (131) 36948-36963]), EPA explained the wide range in the cost and cost-effectiveness estimates as follows: “The main differences between industrial steam generating units and utility steam generating units are that industrial steam generating units tend to be smaller and tend to operate at lower capacity factors. The differences between industrial and utility steam generating units would be reflected in the cost impacts of the various NO_x control technologies. Smaller sized and lower capacity factor units tend to have a higher cost on a per unit output basis.”

Table 9.1 Summary of Annualized Costs for Model Boilers[a] (USEPA 1997)

Fuel Type	Furnace Type[b]	Size (MM Btu/hr)	CC[c]		CC + SNCR[c]		CC + SCR[c]	
			$/yr	%	$/yr	%	$/yr	%
Coal	PC	250	40,040	1	286,530	9	997,740	33
		500	59,020	1	384,460	6	1,605,070	27
		1,000	87,010	1	538,850	4	2,756,820	23
	FBC	100	0	0	173,170	14	NA	NA
		250	0	0	227,480	8	NA	NA
		500	0	0	287,410	5	NA	NA
		1,000	0	0	375,780	3	NA	NA
	Spreader Stoker	100	0	0	184,580	15	583,440	48
		250	0	0	256,000	8	960,920	32
		500	0	0	344,540	6	1,551,210	26
Residual Oil	Field-Erected Water Tube	100	23,970	2	197,060	16	461,860	38
		250	40,040	1	265,600	9	668,940	22
		500	59,020	1	341,770	6	972,550	16
		1,000	87,010	1	453,320	4	1,522,790	13
	Packaged Water Tube	100	23,970	2	197,060	16	461,860	38
		250	40,040	1	265,600	9	668,940	22
Distillate Oil/ Natural Gas	Field-Erected Water Tube	100	0	0	168,910	14	418,880	35
		250	0	0	215,110	7	581,250	19
		500	0	0	261,830	4	818,200	14
		1,000	0	0	324,470	3	1,245,120	10
	Packaged Water Tube	100	23,970	2	194,400	16	443,210	37
		250	40,040	1	258,940	9	622,310	21

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[a] Annualized costs are for a capacity factor of 0.30. Annualized cost expressed as a percentage of steam cost; steam cost based on $6 per 1000 lb steam; and 1,300 Btu of heat input per lb of steam generated

[b] PC = Pulverized Coal; FBC = Fluidized Bed Combustion;

[c] CC = Combustion Control; SCR = Selective Catalytic Reduction; SNCR = Selective Non-Catalytic Reduction

Table 9.2 Model Boiler Incremental Cost-Effectiveness Ranges[a] (USEPA 1997)

Fuel Type	Furnace Type[b]	Control Technology Comparisons[c]	Incremental Cost Effectiveness ($/ton)
Coal	PC	CC vs. Baseline	240 - 440
		CC + SNCR vs. CC	1,720 - 3,375
		CC + SCR vs. CC	6,350 - 9,110
		CC + SCR vs. CC + SNCR	14,070 - 18,040
	FBC	CC vs. Baseline	0
		CC + SNCR vs. CC	2,860 - 13,180
		CC + SCR vs. CC	NA[d]
		CC + SCR vs. CC + SNCR	NA
	Spreader Stoker	CC vs. Baseline	0
		CC + SNCR vs. CC	2,100 - 5,620
		CC + SCR vs. CC	5,900 - 11,100
		CC + SCR vs. CC + SNCR	12,250 - 20,240
Residual Oil	Field-Erected Water Tube	CC vs. Baseline	740 - 2,030
		CC + SNCR vs. CC	2,930 - 13,870
		CC + SCR vs. CC	7,190 - 21,920
		CC + SCR vs. CC + SNCR	14,280 - 35,350
	Packaged Water Tube	CC vs. Baseline	640 - 960
		CC + SNCR vs. CC	7,230 - 13,870
		CC + SCR vs. CC	12,600 - 21,920
		CC + SCR vs. CC + SNCR	21,540 - 35,350
Distillate Oil/ Natural Gas	Field-Erected Water Tube	CC vs. Baseline	0
		CC + SNCR vs. CC	6,170 - 32,140
		CC + SCR vs. CC	14,180 - 49,800
		CC + SCR vs. CC + SNCR	29,190 - 79,250
		CC vs. Baseline	2,030 - 3,040
	Packaged Water Tube	CC + SNCR vs. CC	11,110 - 21,620
		CC + SCR vs. CC	18,460 - 33,240
		CC + SCR vs. CC + SNCR	30,730 - 52,600

[a] Incremental cost-effectiveness at a capacity factor of 0.30 for the range of boiler sizes 250, 500 and 1,000 MMBtu/hr for PC boilers; 100, 250, 500 and 1,000 MMBtu/hr for FBC and field-erected boilers; 100, 250 and 500 MMBtu/hr for spreader stoker boilers; and 100 and 250 MMBtu/hr for packaged boilers

[b] PC = Pulverized Coal; FBC = Fluidized Bed Combustion

[c] CC = Combustion Control; SNCR = Selective Noncatalytic Reduction; SCR = Selective Catalytic Reduction

[d] NA = Not Applicable

9.2 NESCAUM

The NESCAUM report (2000) also evaluated cost-effectiveness of reducing NO_x emissions from existing industrial boilers. Table 9.3 summarizes the type of NO_x control, percent NO_x removal expected, and cost-effectiveness for oil, gas- and coal-fired industrial boilers in the NESCAUM area (retrofit situations).

Table9.3 Cost Estimates of NO_x Control for Industrial Boilers (NESCAUM 2000)

Boiler Type, Size & Fuel Fired	Type of NO_x Control	Percent NO_x Control	Cost-Effectiveness, \$/ton NO_x removed
Oil- & Gas-Fired Industrial Boilers	LNB		<\$2,000
	Gas Reburn	>50	<\$2,000
	Gas Reburn + SNCR	>60	<\$2,000
Coal-Fired Industrial Boiler	LNB	30	<\$2,000
	SNCR	35	\$1,300 to \$1,800
	SCR	90	\$2,000

9.3 FPI Cost Estimates for Industrial Boiler NO_x Control

Table 9.4 was compiled from studies done by pulp and paper companies, and lists the type of NO_x control, percent NO_x removal expected, and cost-effectiveness for various boilers at several mills. The date for each analysis is shown in the first column. All the situations except that for Mill F (greenfield mill) correspond to retrofit applications.

9.3.1 *Detailed NO_x Estimates for Mill H Pulverized Coal-Fired Boiler*

In October of 2001, Mill H developed detailed cost estimates for various NO_x reduction technologies potentially applicable to its 360 MM Btu/hr pulverized coal-fired boiler. Table 10.1 provides a summary of costs for this pulverized coal-fired boiler for four different NO_x control options considered [Option 1: Low NO_x Burners + Overfire Air + NO_x Monitor; Option 2: Low NO_x Burners + Overfire Air + Urea System (SNCR) + NO_x Monitor; Option 3: Ammonia Addition + SCR Catalyst + NO_x Monitor; and Option 4: Low NO_x Burners + Overfire Air + Ammonia Addition + SCR Catalyst + NO_x Monitor]. The summary costs include the annualized capital cost, annual operating and maintenance cost, and total annualized cost. The details of the cost analysis for each NO_x control option are included in Appendix E.

9.4 Comparison of Cost Estimates

It is clear from comparing the mill-generated and EPA-generated cost estimates that the actual costs for installing and operating most NO_x control technologies on FPI boilers will be boiler-specific. The costs can easily exceed the cost-effectiveness threshold of \$2,000/ton NO_x removed, a figure EPA believes is reasonable for retrofit NO_x controls in ozone nonattainment areas. In addition to the typical costs associated with the nature of the boiler whose emissions are to be controlled, other factors would also appear to cause the cost-effectiveness estimates to become significantly higher than \$2,000/ton NO_x removed, principal among them being the extent of NO_x control desired from the baseline level and the cost of installation of each boiler.

Table 9.4 Cost Estimates of NO_x Control in Forest Products Industry Boilers

Boiler Type, Size & Fuel Fired	Type of NO_x Control	Percent NO_x Control	Cost-Effectiveness, \$/ton NO_x removed
Mill A (July 1994) Baseline = 0.4 lb/MMBtu; coal-fired, traveling grate, 225 KPPH	FBC (new)	62.5	\$11,244
	SNCR	30.0	\$1,041
	OFA	10.0	\$2,300
	FGR	5.0	\$4,600
Mill B (Oct. 1994) Baseline = 0.37 lb/MMBtu; oil-fired, 855 MM Btu/hr	Fuel Switching	45.0	\$20,158
	FGR	5.0	\$5,840
	LNB	5.0	\$3,239
	LNB + OFA	25.0	\$2,023
	LNB + OFA + FGR	32.0	\$2,476
Mill C1 (Feb. 1996) Coal, PC - 500 MM Btu/hr	LNB	30.0	\$3,286
	SNCR	50.0	\$4,826
	SCR	80.0	\$6,755
Mill C2 (Feb. 1996) Gas – 150 MM Btu/hr	LNB	40.0	\$3,422
	LNB + FGR	60.0	\$3,666
	SNCR	50.0	\$6,766
	SCR	90.0	\$5,563
Mill D (Jan. 1996) Sludge, FBC, 90 MMBtu/hr	SNCR	--	\$3,400
Mill E (Dec. 1996) Baseline – 0.25 lb/MMBtu; wood-fired boiler, stoker	SNCR	40.0	\$3,400
Mill F1 (March 1997)[a] Oil/Gas, Package Boiler, 365 MM Btu/hr, baseline = 0.10 lb/MMBtu	O/R[b]	90.0	\$8,580
	SCR	75.0	\$6,276

(Continued on next page. See notes at end of table.)

Table 9.4 Continued

Boiler Type, Size & Fuel Fired	Type of NO_x Control	Percent NO_x Control	Cost-Effectiveness, \$/ton NO_x removed
Mill F2 (March 1997)[a] Oil/Gas, Power Boiler, 781 MM Btu/hr, baseline = 0.10 lb/MMBtu	O/R[b]	90.0	$7,142
	SCR	75.0	$5,816
Mill G1 (June 1998) Solid Fuels[c]	Staged Comb/LNB/GR[d]	5 to 30	$1,000 to $2,500
Mill G2 (June 1998) Oil/Gas/low fuel bound N	FGR/LNB	30 to 80	$1,000 to $3,000
Mill G3 (June 1998) All Fuels (solid, liquid, gas)	SNCR	33 to 50	>$1,700
	SNCR/Hybrid[e]	50 to 85	$3,000
	SCR	90.0	$6,000 to $7,500
	O/R[2]	90.0	$7,500 to $9,000
Mill H (Oct. 2001)[f] Baseline – 0.83 lb/MMBtu – Coal, PC – 360 MMBtu/hr	LNB + OFA[g]	30.0	$1,989 ($4,746[h])
	LNB + OFA + SNCR[g]	60.0	$1,645 ($3,925[h])
	NH_3 Addition + SCR[g]	60.0	$2,440 ($5,821[h])
	LNB/OFA/NH_3 SCR[g]	85.0	$2,342 ($5,588[h])

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[a] greenfield mill, never built; [b]O/R=Oxidation/Reduction Scrubbing; [c]stokers: wood, coal, TDF; burners: oil; pulverized coal; fuels w/high fuel-bound N; [d]GR=gas reburn; [e]urea injection followed by small catalyst; [f]details provided in Appendix E; [g]including NO_x monitor (LNB & OFA total capital cost=$2,910,934; NO_x monitor & flow monitor total capital cost=$628,878; SNCR total capital cost=$1,468,719; SCR total capital cost=$5,348,505); [h]if based on ozone season only, May 1–Sept. 30

Table 9.5 Summary of Estimated Costs and NO_x Control Options for Mill H Pulverized Coal-Fired Boiler

Capital Amount Total Invested[a]	Annualized Capital Cost[b]	Annual Operating & Maintenance Cost[c]	Total Annualized Cost	Estimated Percent NO_x Removal	Annual NO_x Reduction (tons)	Annualized Cost ($)/ Ton of NO_x Reduction	Annualized Cost ($)/ Ton of NO_x Reduction[d]	Capital Cost ($)/Ton for NO_x Reduction[d]
Option 1: 3,500,000	569,450	215,000	784,450	30%	395	1,989	4,746[d]	21,174[d]
Option 2: 4,900,000	797,230	500,300	1,297,530	60%	789	1,645	3,925[d]	14,822[d]
Option 3: 5,977,000	972,458	954,350	1,926,808	60%	789	2,440	5,821[d]	18,057[d]
Option 4: 8,900,000	1,448,030	1,169,175	2,617,205	85%	1,118	2,342	5,588[d]	19,003[d]

Boiler NO_x Control Options (see details in Appendix C)
Option 1: Low NO_x Burners + Overfire Air + NO_x Monitor; Option 2: Low NO_x Burners + Overfire Air + Urea System (SNCR) + NO_x Monitor
Option 3: Ammonia Addition + SCR Catalyst + NO_x Monitor; Option 4: Low NO_x Burners + Overfire Air + Ammonia Addition + SCR Catalyst + NO_x Monitor

[a] Incorporates $600,000 of capital for NO_x monitor as boiler is not subject to Subpart D (see Tables 8 to 11 for detailed cost summary)

[b] Annualized Capital Recovery Factor of 0.1627 (at 10% interest) calculated using EPA-OAQPS Costing Manual EPA-453/R95

[c] Using the following estimated annual operating cost factors:

Monitor: $40,000/ year for consultants, certification, testing, cal gas (does not include maintenance)
Services: $50,000/year for service based on a southeastern mill's NALCO SNCR system
Maintenance: 5% of capital investment (Includes operating, maintenance, and supervisory labor, and power, materials, taxes, and misc.)
Urea: $500/ton NOx removed ($250/ton of 50% urea delivered and used)
Catalyst: $800,000 replacement cost every 2 years

[d] Assuming control applied during ozone season only (153 days/year; May 1 - September 30);

Operating Assumptions

(1) Riley Boiler operates at 360 MMBtu/hr burning pulverized coal only; (2) 2000 Coal shipments averaged 13,191 Btu/lb; (3) Average tons of coal burned per hour = 13.65; (4) 2000 MAERS emission factor for NO_x equaled 22 lbs NO_x/ton coal (0.8339 lbs NO_x/MMBtu); (5) Average NO_x generation by Riley Boiler = 300.3 lbs./hr; (6) Current emissions of NO_x from the Riley are about 300.3 lbs./hr, 3.6 Tons/day, and 1,315.3 tons/yr

10.0 SUMMARY

There is growing regulatory pressure for NO_x emission reductions, particularly in and near ozone nonattainment areas. Although utility boilers have been the major target for these reductions, industrial boilers are under increasing scrutiny. As a result, NO_x control measures are being installed at a rapid pace on both utility and industrial boilers.

NO_x control measures can be categorized as either combustion modification or flue gas treatment. The applicability of a particular control measure to a given boiler will depend upon the boiler type, design parameters, fuel type, and operating conditions.

In this report, currently available NO_x control measures are described and their applicability to boilers operated by the forest products industry is discussed. Emerging technologies with potential applicability are also reviewed. Differences between utility and industrial boilers that influence the applicability or effectiveness of certain NO_x control measures are enumerated. Estimates of the capital and operating costs for NO_x control measures developed by EPA, NESCAUM, and individual companies are presented.

Relative to combustion modifications, the following observations may be made.

- Combustion modifications such as low-NO_x burners with overfire air and flue gas recirculation work well with oil- and gas-fired boilers.
- For coal-fired boilers, low-NO_x burners and overfire air have been successfully applied to tangential- and wall-fired units, whereas reburning is the only current option for cyclone boilers. Among emerging technologies worth consideration are the gas reburn technology (when gas is available), the low temperature oxidation technique using ozone injection, and layered technologies such as LNB with OFA combined with SNCR.

Relative to flue gas treatment, the following observations may be made.

- Considering reasonably available and proven NO_x control technologies applicable to solid fuel-fired industrial boilers, only SNCR and SCR would be deemed applicable when control efficiencies exceeding about 40% are desired.
- Outstanding issues for applying SNCR and SCR technologies to boilers with swinging loads remain, especially with respect to ammonia slip, and reliable removal efficiencies.
- Base-loaded oil-, coal- and gas-fired boilers can perhaps be controlled by SNCR or SCR technologies, but site-specific factors must be considered.
- The use of SCR for biomass boilers or combination boilers firing biomass of all configurations, even when base-loaded, needs further investigation since the ash concentrations in the uncontrolled flue gas are quite high and the wood ash is known to be rich in alkali metals that could potential act as catalyst poisons.
- SNCR for stoker-type biomass boilers or combination boilers firing biomass, even when base-loaded, also needs to be further investigated since insufficient dispersion of the ammonia or urea injected could lead to significant ammonia slip or low control efficiencies.
- The performance of SNCR and SCR on swing-loaded industrial boilers has not been demonstrated to deliver consistently high levels of NO_x reduction efficiencies.

The most cost-effective strategy for installing NO_x control on an industrial boiler could involve the following steps (in succession) for higher levels of NO_x control.

- Step 1 – Fine-tune the boiler (e.g., burner modification or replacement, process modification and/or energy efficiency improvements).
- Step 2 – Improve or replace the convective section to preheat process fluid, improve heater's efficiency and decrease firing rate.
- Step 3 – Install low NO_x and/or ultra low NO_x burners.
- Step 4 – Investigate other combustion modifications such as OFA, FGR and NO_x tempering.
- Step 5 – Investigate use of SNCR.
- Step 6 – Investigate use of one of the emerging NO_x control technologies such as gas reburn and catalytic or ozone oxidation/scrubbing.
- Step 7 – For boilers with relatively clean flue gases (gas-, oil-, or coal-fired) that also have access to the required temperature windows without severe energy penalty, investigate installing SCR.

Relative to NO_x control costs, the following observations may be made.

- Cost-effectiveness estimates vary considerably from one application to another, depending on factors such as baseline and final NO_x emission levels, specific site installation costs, age and condition of the boiler, type of boiler, fuel types, and capacity utilization.
- Estimates developed by individual mills showed NO_x control cost-effectiveness for mill boilers ranged from \$2,000 to over \$6,000 per ton NO_x removed. The estimates generally exceeded generic estimates prepared by EPA and NESCAUM for similar control measures.

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APPENDIX A

THE 0.2 lb $NO_X/10^6$ Btu EMISSION STANDARD FOR INDUSTRIAL BOILERS – AF&PA PETITION CHALLENGING AND EPA LEGAL BRIEF DEFENDING THIS STANDARD AND NCASI COMMENTS ON EPA'S LEGAL BRIEF

In November of 1998, AF&PA, along with several other organizations, including the Council of Industrial Boilers (CIBO), submitted a petition to the DC Circuit Court challenging the revised Subpart Db standards of performance for NO_x applicable to fossil-fuel fired steam-generating units ("boilers") promulgated by EPA on September 16, 1998. The petition claimed EPA did not consider adequately the feasibility of installing SCR on coal-fired industrial boilers (or coal/wood and coal/oil boilers) which have different characteristics than utility boilers, such as swinging loads. This petition highlighted the following characteristics pertinent to pulp and paper industry boilers that differentiate them from utility boilers, thereby calling the applicability of a uniform technology-based NO_x standard into question:

- **Load Swings** - Pulp mill combination and power boilers frequently exhibit wide and rapid load swings that are not consistent with the steady conditions required for effective use of either SNCR or SCR NO_x control technologies. The load swings produce variable temperature conditions in the boiler, causing the temperature zone for NO_x reduction to fluctuate, making it more difficult to know where to inject the reactants.

- **Temperature Incompatibility** - Combination and power boilers are affected by temperature profile incompatibility. To obtain the required temperature window for SCR (550 to 750°F), the only location to install this technology is upstream of the particulate matter control device, yet this is where flue gases are dirty and can foul the catalyst rapidly. Downstream of the PM control device, the temperature is too low for the catalyst to be effective.

- **Burning of Sulfur-Containing Gases** - Many kraft mills use their boilers to combust pulp mill gases containing reduced sulfur compounds. This process may constrain combustion patterns in that it requires high temperatures to be maintained to ensure complete oxidation.

- **Adverse Trade-Offs -**There are very few NO_x reduction options available for most large non-utility combustion sources, but even these options (e.g., low NO_x burners, overfire air, and flue gas recirculation systems) often have adverse trade-offs.

- **Unproven Technologies for High Levels of NO_x Control -** Even these options likely would not achieve the levels of NO_x reduction outlined in any of EPA's ozone transport rule makings, including the Subpart Db revisions. The 60% reductions proposed as part of the Section 126 rulemaking likely would require the use of SCR or SNCR controls, technologies which, for the most part, are untested and infeasible for pulp and paper mill boilers. These technologies must be operated on a continuous basis within a specified temperature range in order to be effective. The type of fuel burned influences the design of the technology, and FPI facilities' frequent fuel changes and co-firing of multiple fuels would result in design and operational problems.

- **SCRs Unproven for Biomass Applications –** Many of the FPI boilers are fired to a large degree by biomass. SCRs are not a proven NO_x reduction technology for biomass applications. There is test evidence of catalyst poisoning in sludge-burning applications and accelerated deterioration in bark-burning applications. Furthermore, carryover of burning embers from the furnace to the desired temperature zone for SCRs is expected in varying degrees unless the catalyst is installed after a "hot" dust collector.

- **Space Limitations For Installing SCRs** - SCRs and the associated reagent systems require considerable space, which would present problems for many pulp and paper mill applications.
- **Lack of Guarantee for SCRs on FPI Boilers** – Boiler owners are finding that vendors of SCR and SNCR technologies are unwilling to provide performance guarantees that the controls will meet the level of reduction called for in the EPA proposal.
- **EPA Claims of Transferability of SCR Experience on One Boiler Type to Other Boiler Types –** Industry experience conflicts with this, both on a technical basis and on a cost basis.

On July 30, 1999 EPA submitted a legal brief to the DC court outlining its arguments why certain consolidated petitions challenging the revised Subpart Db standards of performance for NO_x applicable to fossil-fuel fired steam-generating units ("boilers") promulgated by EPA on September 16, 1998 (viz., 0.2 lb NO_x /10^6 Btu for utility and industrial boilers firing more than 10% gas, coal, or oil on an annual basis) should be denied (USEPA 1999). According to EPA, the petitions addressed three main issues:

1. whether in revising the standards of performance for NO_x emissions applicable to new boilers, EPA properly chose selective catalytic reduction in combination with combustion controls as the best system of emission reduction, taking into account environmental impacts, costs and energy requirements
2. whether EPA reasonably established uniform emission standards for newly constructed boilers based on the record before it
3. whether EPA properly assigned a 50% credit for the steam exported from cogeneration units for purposes of determining compliance with the revised output-based standard for new utility boilers

In its brief, EPA mentioned it chose "selective catalytic reduction in combination with combustion control technologies as the best system of emission reduction because those technologies could obtain significant NO_x reductions at reasonable costs with minimal energy requirements." The revised limit for coal-fired industrial boilers was 0.20 lb/MMBtu heat input, 30-day rolling average. The brief contained the following points relevant to NO_x emissions control.

- For industrial boilers, data on SCR were available for gas-fired units only.
- Results of SCR coal-fired utility boiler data analyses were used to assess appropriateness of SCR for industrial boilers.
- EPA considered similarities and differences between utility and industrial boilers.
- EPA obtained cost data from utility questionnaires, vendor information, and published literature and combined these with performance data and theoretical constructs of 38 utility and 22 industrial boilers to arrive at control costs.
- For a boiler operating at 65% capacity, average cost-effectiveness for SCR was about \$1,500 and \$2,000 per ton NO_x removed for utility and industrial boilers, respectively, over the cost required to meet the regulatory baseline.

- Since combustion controls prevent NO_x formation during combustion, their effectiveness depends, in part, on the fuel used (e.g., the nitrogen content of the fuel) and the boiler design.
- The effectiveness of flue gas technologies, like SCR, however, does not depend on these factors - they are applied after the combustion phase and destroy NO_x regardless of how it was formed.
- To avoid plugging and corrosion of catalyst during use of SCR on high S coal applications, vendors have modified catalyst composition, including pore size; also, they have reduced the temperature range for the NO_x chemical reduction in new catalysts.
- Poisoning of SCR catalysts by alkaline metals—poisoning caused by alkalis in water soluble form—most alkaline metals in coal-fired flue gas are not water soluble.
- Alkaline metals in oil-fired boiler emissions are water soluble—thus greater poisoning potential—Mg (fuel oil additive) and Na (sea water contamination).
- EPA recognized differences between industrial and utility boilers and focused extensively on the one main difference viz., more fluctuating loads.
- EPA evaluated CEM data on two utility boilers with cycling loads—32 to 100% and 28 to 84%—0.15 lb/MMBtu met on a 30-day rolling average.
- Issue of overcoming effect of flue gas temperatures while operating at low loads can be addressed by including an economizer bypass duct.
- Other issues arising from operating at low loads such as lower gas flow rates and catalyst poisoning were discounted by EPA.
- EPA claimed "Because SCR responds to NO_x levels in the flue gas, adding wood should not affect results, particularly given that coal represents the worst case scenario in terms of NO emissions."
- Wood-fired boilers using SNCR, which operates similarly to SCR, can achieve limits of 0.06 to 0.07 lb/MMBtu, far below the revised NSPS limits, at reasonable costs.
- EPA's regulations do not require use of specific fuels or technologies—not favoring natural gas—fluidized bed units using combustion controls alone, industrial boilers using SNCR, or gas reburn alone can achieve the limit.

NCASI performed a technical review for AF&PA of the July 30, 1999 legal brief submitted by EPA to the DC court in which it included the following comments.

- EPA cites two domestic gas-fired boilers with SCR with <0.01 lb NO_x /10^6 Btu. If these were base-loaded, gas-fired boilers equipped with SCR, it is easy to understand how the flue gases could be controlled for NO_x to such low levels; however, it is unclear whether these levels could be achieved for swing-loaded boilers. Also, since no emissions data were available for the two foreign coal-fired boilers, it is not clear why these were identified.
- EPA's assertion that utility and industrial forest products industry boilers burn the same fuels is untrue. Also, EPA states "boiler type is irrelevant for SCR because the technology is applied downstream of the combustion process." This is correct except, as shown later, the type of boiler fuels could impact the particulate and/or SO_2 loading in the gases entering the SCR system, which may have an impact.

- EPA cites data from "two utility boilers with cycling loads analogous to industrial boilers." How was this determination of *analogous* made? For example, were these cycling on a day-to-day basis or more slowly over a 30-day period?
- While operating at low loads, the lowered flue gas temperature that results is no doubt the most important factor that could affect SCR performance. EPA recommends "adding an economizer bypass duct." First, this recommendation is not a "catalyst design" as mentioned, but rather a design change of the ductwork. SCR requires a certain fixed temperature window before the flue gases enter the catalyst section. Bypassing the economizer section will no doubt raise the gas temperature, but this rise will depend on the boiler load at any given time. Does EPA have data to show that achieving the desired temperature range before the catalyst section can be met at various boiler loads by just bypassing the economizer section?
- On page 45, EPA states "Because SCR responds to NO_x levels in the flue gas, 63 Fed. Reg. 49, 444/3, adding wood, as Petitioners suggest, should not affect the results, particularly given that coal represents the worst case scenario in terms of NO_x emissions." There is, however, a major difference between wood- and coal-fired boilers. EPA's AP-42 document gives an uncontrolled particulate matter emission factor for pulverized, bituminous coal, dry bottom boiler operations of 10 lb/ton or about 0.38 lb/10^6 Btu. The same AP-42 document gives an uncontrolled PM emission factor for bark firing in a spreader-stoker of 48 lb/ton or about 5.33 lb/10^6 Btu, i.e., about a 14 times higher particulate loading on a heat input basis is expected from wood residue-firing than coal-firing. It is not clear EPA has considered the impact upon SCR performance from increased PM loading in combination bark/coal boilers. Note that the use of SNCR is likely not affected by PM loading.
- It is not clear whether the 0.06 to 0.07 lb $NO_x/10^6$ Btu quoted as having been achieved by wood-fired boilers with SNCR are for base-loaded or swing-loaded wood-fired units.

APPENDIX B

NEW SOURCE PERFORMANCE STANDARDS, SUBPARTS Da AND Db – SUMMARY OF PUBLIC COMMENTS AND EPA RESPONSES

EPA summarized the public comments it received with respect to its proposed amendments on July 9, 1997 to subparts Da and Db of 40 CFR Part 60 and the responses to such comments in September of 1998 (USEPA 1998d). Several comments pertinent to FPI boilers and EPA responses to such comments are summarized below.

a) Selective Catalytic Reduction as Best Demonstrated Technology

Comments on coal-fired industrial boilers

- SCR is not the best demonstrated technology for coal-fired industrial boilers.
- EPA should consider the potential problems associated with SCR, including costs, catalyst poisoning, and oil ash coating catalyst.
- Deactivation of catalyst from alkali sulfates and excess SO_3 in the flue gas.

Comments on appropriateness at pulp and paper mills

- SCR not appropriate for combination boilers at pulp and paper mills
- Boilers subject to wide, sudden changes in load that complicate use of SCR
- Other problems – high particulate loadings, sulfur poisoning, difficulty in maintaining temperatures to minimize NO_x and HAP generation

Comments on oil-fired boilers

- SCR is not the best demonstrated technology for oil-fired industrial boilers.
- Annual averaging period preferred if 0.20 lb/10^6 Btu is set as standard.

EPA Response

- Additional U.S. experience - EPA obtained new data from three U.S. utility boilers with SCRs that suggested all three could meet the input-based NO_x standard of 0.15 lb/MM Btu and output-based standard of 1.6 lb/MWh on a 30-day rolling average (one if facility “improves” SCR performance).
- 30-day averaging period accommodates fluctuations in performance due to changing loads - Data from two U.S. utilities showed that SCR can meet the proposed standard over a 30-day averaging period under cycling conditions (one cycled from 32 to 100% load, the second from 28 to 84%).
- Expected temperature range at economizer exit is factored into selection of SCR catalyst formulation.
- In cases of low load with low gas velocity to keep ash in suspension, an ash hopper can be added to divert the ash from reactor and catalyst surface.

- An economizer bypass can be added to avoid low boiler exit temperatures at low loads.
- Developments in catalyst technology minimize the impact of poisoning.
- A 1997 study identified 212 worldwide SCR installations on coal-fired units covering different types of boilers subject to varying operating conditions and firing a variety of coals.
- Issues such as burning high sulfur coals, catalyst poisoning, SCR use in high dust vs. low dust environments, etc. are more cost-based issues dealing with catalyst life.

b) Selective Non-Catalytic Reduction

Comments on Fluidized Bed Combustion Boilers (FBCs)

- SNCR not demonstrated on circulating FBCs which have inherently low combustion temperatures - three of five CFBCs that use SNCR stated SNCR did not work when units were operated at less than maximum capacity.

EPA Response

- Subpart Db background information document (BID) states that flue gas temperatures exiting the furnace range from 2,200 ± 200°F at full load to 1,900 ± 125°F at half load.
- Addition of hydrogen or other hydrocarbon reducing agent while injecting NH_3 or urea lowers effective NO_x reduction temperature range.

c) Control Technology Costs

Comments on Estimated Costs Being Too Low

- EPA cost estimates for SCR are much too low since they were extrapolated from an earlier study that focused on retrofit costs for existing plants, and did not consider site layout, with boiler conditions not typical of new units. EPA estimates are only 65% of values estimated in a recent EPA/DOE/EPRI technical conference.
- SCR systems require more energy to operate due to a pressure drop across the catalyst bed.
- Costs associated with fouling of air heater surfaces by ammonium salts, and waste disposal costs for the spent catalyst need to be considered.
- Additional costs associated with (a) lower catalyst life than 5 years due to catalyst poisoning, (b) disposal of ash with higher nitrogen content, (c) plugging of air heaters by ammonium bisulfate and fouling of catalyst by calcium and ammonium salts, (d) storing large quantities of ammonia, (e) requiring open space for the catalyst bed, and (f) handling and disposal of spent ammonia catalyst were not considered.
- Unplanned shutdown due to control device malfunction for utility boilers can be managed differently than for industrial boilers that need the steam for the manufacturing operation. A considerable economic penalty follows a shutdown in the case of the latter.
- Cost-effectiveness values for coal units using SCR are calculated using a baseline NO_x emission rate of 0.45 lb/MM Btu when low NO_x burners can easily meet a 0.30 lb/MM Btu emission rate.

EPA Response

- Cost estimates were made using actual baseline emissions from planned, new units in the country and using more recent information obtained by the Acid Rain Division.
- Energy impact of SCR amounts to only about 0.4% of boiler output, which is justified.
- EPA used a three-year catalyst life for coal-fired units; the agency did account for different types of coals, with varying ash contents in the costing analysis; indirect costs from downstream effects from SCR have been included; additional storage costs for ammonia were considered in indirect costs for SCR and SNCR; retrofit costs were included in EPA's analysis; spent catalyst costs were also included in indirect costs of SCR.
- In the case of a malfunction, the NSPS provisions do not apply for the period of the malfunction, assuming the source acted to repair the malfunction soon thereafter.
- Model plants used a higher emission rate (0.45 lb/MM Btu), but the impacts analysis used emission rates based on projected permit limits, which are lower.

Comments on Fuel Switching Costs

- Natural gas can cost more than twice as much as coal (Btu basis) when purchased on a "curtailment basis."

EPA Response

- The proposed standards are written in a "fuel-neutral" format that would allow use of natural gas but would not require it when fuel costs exceed the costs of meeting the standard using alternative means such as the use of SCR.

APPENDIX C

RACT/BACT/LAER NO_X CONTROL OPTIONS FOR BOILERS – INFORMATION SUBMITTED BY FOREST PRODUCTS COMPANIES

Mill A - RACT Proposal – July 1994

Two coal-fired spreader stokers – Alternatives for NO_x Control

- Conversion to Fluidized Bed Combustion – technically feasible, but economically infeasible – estimated cost-effectiveness was about \$11,200/ton NO_x removed
- SNCR – economically feasible, but unproven technology for the type of boilers – specifically, not proven for stokers over a wide range of load levels on a potentially rapidly varying basis – rejected based on technical grounds
- Modification of Grate and Overfire Air System – small reductions in NO_x – technically infeasible – control of temperature to ensure effectiveness was found to be beyond the capability of existing technology – costs were too high - \$2,300/ton NO_x reduction
- FGR – small reduction feasible – technically infeasible – flue gas temperature cannot be controlled for proper combustion at all loads - \$4,600/ton NO_x reduction

Mill B, RACT Proposal – Aug. 1994

Two pulverized coal-fired boilers - separated OFA was considered not technically feasible due to the following reasons:

- insufficient space in the furnace zone to accommodate installation of system
- unknown if boiler wall tubes could be relocated to accommodate the OFA ports
- boiler materials inadequate to accommodate corrosive conditions created in the reduction zone
- risk of flame stability problems and, potentially, the creation of explosive conditions
- adverse effect on boiler energy efficiency from improperly functioning OFA system
- no prior installation of OFA system as retrofit on similar PC boilers

One wood-coal combination boiler (spreader stoker) - FGR was considered not technically feasible due to:

- feasibility and effectiveness of FGR was questionable because of uncontrollable effects associated with the temperature of the flue gas – if gas is too hot, the grate may overheat – if too cold, this may lead to higher PM, CO, and VOC emissions
- PM entrained in recirculated flue gas could cause localized pluggage of grate
- no prior installation of FGR as retrofit on a similar mixed fuel stoker boiler

Mill C – BACT Analysis – October 1994

Power boiler, 855 MMBtu/hr (85% from No. 6 fuel oil, rest wood), oil burned through burners, wood burned on grate - NO_x control technologies considered – LNB, FGR, LNB w/OFA, LNB with OFA and FGR, and fuel switching

LNB - technologically feasible

FGR - technologically feasible, especially in combination with LNB and OFA

OFA - technologically feasible

Staged Combustion – considered technologically infeasible for this boiler

BOOS – not applicable to this boiler since only 6 burners available

Gas Reburning – not applicable, since gas not available

Mill D – BACT Proposal – January 1997

Bark Boiler – 622 MMBtu/hr

- FGR - not applied to wood-fired boilers
- Low excess air - generally not applicable to low N, high-moisture fuels that require more excess air to assure flame stability and effective combustion to control formation of CO, VOC, and PM emissions
- SCR
    - Not demonstrated on wood solid fuel boilers
    - Use of solid fuels can result in catalyst contamination even with efficient PM control system
    - High moisture levels in exhaust air would result in inefficient SCR operation
    - Exhaust gases need to be reheated by at least 150°F, representing about 40 MMBtu/hr or about 6.5% of the boiler heat rate
- SNCR
    - technically feasible
    - economic analysis results in a cost-effectiveness of $3,400/ton NO_x removed - considered cost-prohibitive
    - adverse environmental impacts due to ammonia slip of 10 to 25 ppmv
    - storage of ammonia or urea poses potential for accidental releases
- Enhanced staged combustion with OFA – proposed as BACT – 0.25 lb/MMBtu

Mill E – Greenfield Mill - BACT Analysis - March 1997

Combination Boiler (wood, sludge, OCC rejects, oil, gas) – 500 MMBtu/hr

- FGR – technically infeasible – would have to withstand high temperature and particulate matter (PM) loading in the flue gas stream – does not affect fuel NO_x from wood combustion – not demonstrated on wood waste-fired boilers in pulp and paper industry
- SCR – technically infeasible – catalyst would be poisoned by sulfur compounds present - PM would plug catalyst – reheat necessary if installed downstream of ESP – not demonstrated on wood waste-fired boilers in pulp and paper industry
- SNCR – technically infeasible – temperature would be above the required temperature window, and residence time would be less than the 1 second required
- Oxidation/Reduction Scrubbing – technically infeasible – high moisture content would result in dew point exceeding max temperature required for effective scrubbing
- LNB – applies to fuel oil and gas – selected as BACT – 0.30 lb/MMBtu

Package Boiler (oil, gas) – 365 MMBtu/hr

- SNCR – technically infeasible – temperature would be above the required window and residence time would be less than the 1 second required
- Oxidation/Reduction Scrubbing – economically infeasible – \$8,580/ton NO_x removed
- SCR – economically infeasible – \$6,276/ton NO_x removed
- LNB & FGR – selected as BACT – 0.10 lb/MMBtu

Power Boiler (oil, gas) – 781 MMBtu/hr

- SNCR – technically infeasible – temperature would be above the required window and residence time would be less than the 1 second required
- Oxidation/Reduction Scrubbing – economically infeasible – \$7,142/ton NO_x removed
- SCR – economically infeasible – \$5,816/ton NO_x removed
- LNB & FGR – selected as BACT – 0.10 lb/MMBtu

BACT/LAER Study of NO_x Reduction Technologies Study, June 1998

A consulting company carried out a comprehensive study evaluating several NO_x reduction technologies for various boilers within a company. The following summarizes their major findings:

- Load Reduction, Excess Air Reduction, Fuel Switching, Fuel Biasing, Air Staging, BOOS, Water Injection - all these techniques are limited to applications where they can be effectively implemented without sacrificing steam load - percent reductions in NO_x of between 5 and 10% feasible where applicable - cost-effectiveness = < \$500/ton NO_x reduced
- Staged Combustion/Low NO_x Burners – feasible on the stoker-fired boilers – cost per ton NO_x removed = \$1,000 to \$2,500 - percent reduction in NO_x 5 to 30 (maximum)
- Flue Gas Recirculation/LNB – LNB extends the flame and FGR limits flame temperature more than OFA – up to 30% of flue gases recirculated to dilute amount of O_2 present in

combustion air, thereby delaying combustion process – also stages air within the burner itself to reduce thermal NO_x – only thermal NO_x reduced – good for gas and low fuel-bound N oils only - cost per ton NO_x removed = \$1,000 to \$3,000 - percent reduction in NO_x 30 to 80 (maximum)

- SNCR – due to the narrow temperature window, applicable to base-loaded boilers only - cost per ton NO_x removed = >\$1,700 - percent reduction in NO_x 33 to 50
- SNCR Hybrid Systems – rely on SNCR followed by a small catalyst grid in a lower temperature zone – allows for increasing the temperature window between 1500°F and 1900°F and possibly allows for some variations on boiler load – problems with particulate plugging unless hot-side ESP used – cost per ton NO_x removed = \$3,000 – percent reduction in NO_x 50 to 85 (maximum)
- SCR – large catalyst bed – prone to plugging from PM – not suitable for PC units or other solid fuel-firing methods like stokers – equipment size often quite large leading to space limitations for retrofitting – cost per ton NO_x removed = \$6,000 to \$7,500 – percent reduction in NO_x up to 90 (maximum)
- Oxidation/Reduction Scrubbing – 2-stage process involves oxidation of NO to NO_2, using ozone or sodium hypochlorite – 2nd stage uses caustic to remove NO_2 – capital intensive, with two scrubbing towers, recirculation tank, pre-mix tank, blowers, heat exchanger, and a waste handling system – limited to maximum temperature of 200°F which makes it very prone to corrosion – cost per ton NO_x removed = \$7,500 to \$9,000 – percent reduction in NO_x up to 90 (maximum)

APPENDIX D

PERMITTING DECISIONS AND NO_X EMISSION LIMITS IN EPA'S RACT/BACT/LAER CLEARINGHOUSE DATABASE FOR FPI BOILERS

RACT/BACT/LAER Clearinghouse

Table D1 provides a summary of relevant information on FPI boiler NO_x control extracted from reports in the RACT-BACT-LAER Clearinghouse for the period between 1992 and 2001. This information provides a look at the type of NO_x limits and pollution prevention/add-on descriptions outlined in these reports. It is clear from the information presented here that during the past decade, LNBs with FGR and LNB were the most commonly recommended NO_x control technologies for oil/gas and coal-fired boilers, respectively, while good combustion control was typically the only recommendation for wood waste-fired boilers.

Table D1 Summary of RACT-BACT-LAER Clearinghouse (RBLC) Information on NO_x for FPI Boilers - 1992 to 2001

Permit Date	Boiler Description	Primary Fuel	MM Btu/hr[1]	NO_x Limit, lb/10^6 Btu	Basis	P2/Add-on Description	Process Notes	Company
7/7/93	Coal-fired	Coal	174.7	0.20	BACT -PSD	Good Combustion Control	Not built	Seminole Kraft, Jacksonville, FL
12/21/94	Coal-fired	Coal	214	0.51	RACT	LNB, 30% eff.; some nat. gas	Pulverized Coal	IP, Erie. PA
9/10/96	Power Boiler	Wood/Coal	1600	0.50	BACT -PSD	Contd. Efficient Operation w/LNB	other fuels[4]	Weyerhaeuser, Columbus, MS
1/25/96	Fluidized Bed	Sludge	90	100 ppm	Other	SNCR		Fort James, Green Bay, WI
3/10/97	Combination	Wood/ Sludge	494	0.30	BACT	LNB (applies to oil & gas)	Not built	Mid-South Project
12/17/98	Oil-fired	No. 6 Oil	212	0.425	BACT -PSD	LNB w/FGR - 20% control	Stack Tests	Rayonier, Fernandina Bch, FL
3/10/97	Package	No. 2 Oil/ Gas	365	0.10	BACT	LNB w/FGR	Not built	Mid-South Project
3/10/97	Power Boiler	No. 2 Oil/ Gas	781	0.10	BACT	LNB w/FGR	Not built	Mid-South Project
8/15/94	Oil-fired	No. 6 Oil	223	0.30	BACT -PSD			Mead, Stevenson, AL
7/1/93	Oil-fired	No. 2 Oil	240	0.10	BACT -PSD	LNB w/FGR	75% efficiency	Appleton Papers, Combined Lock, WI

Table D1 (Cont'd). Summary of RACT-BACT-LAER Clearinghouse (RBLC) Information on NOx for FPI Boilers, etc. – 1992 to 2001

Permit Date	Boiler Description	Primary Fuel	MM Btu/hr[1]	NO_x Limit, lb/10^6 Btu	Basis	P2/Add-on Description	Process Notes	Company
7/1/93	Wood-fired	Wood Waste	718	150 ppm[1]	BACT-Other	Good Combustion Control	SNCR rejected[3]	Scott Paper Co., Everett, WA
10/28/94	Wood-fired	Wood Waste	91	0.23	BACT-PSD			Weyerhaeuser, Millport, AL
12/19/94	Wood-fired	Wood Waste	275	0.23	BACT-Other	No Controls		Kes Chateaugay Project, NY
12/21/94	Wood-fired	Bark/Wood	326	0.54	RACT	None		IP, Erie. PA
4/11/95	Wood-fired	Wood Waste	244	0.30	BACT-PSD	None		Georgia Pacific, Gloster, MS
4/17/96	Wood-fired	Bark/Wood	470	0.30	BACT	Good Combustion	also natural gas	Willamette, Bennettsville, SC
1/15/97	Wood-fired	Bark/Wood	622	0.25	BACT-PSD	Combustion Control	other fuels[5]	Mead, Stevenson, AL
12/9/97	Wood-fired	Wood Waste	710	0.25	BACT-PSD	Addition of tertiary air system; 30% η	other fuels[6]	Champion Interntl, Courtland, AL
12/10/97	Wood-fired	Bark	775	0.3	BACT-PSD	LNB for gas/oil burners; 50% eff.	includes sludge	Gulf States, Demopolis, AL
5/13/98	Wood-fired	Wood	245.3	115 ppm[2]	GACT	SNCR	Stack Tests	Sierra Pacific Ind., Redding, CA
10/14/98	Wood-fired	Wood	98	0.3	BACT-PSD	None		Gulf States, Moundville, AL

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[1] @ 7%O_2 or about 0.25 lb/MM Btu; [2] @12%CO_2 or about 0.23 lb/MM Btu; [3] NH_3 injection led to visible plume; [4] sludge/gas/ oil/NCG; [5] NRP/rejects/sludge/NCG; [6] sludge/NRP/TDF/gas/NCG

APPENDIX E

DETAILED COST ANALYSIS FOR MILL H COAL-FIRED BOILER

Table E1 Low NO_x Burners and Overfire Air Installation Costs at Mill H

	Quantity	Price	Cost
Direct Costs			
*Purchased Equipment Costs**			
Low NO_x Burner Assemblies	4	$75,000	$300,000
Replace Burner Management System	1	$150,000	$150,000
Replace Forced Draft Fan	1	$125,000	$125,000
Replace Forced Draft Fan Motor	1	$40,000	$40,000
Lot Windbox Modification Materials	1	$75,000	$75,000
Lot OFA Nozzles & Pressure Part Openings	1	$180,000	$180,000
Lot New Instrumentation & PLC Controller	1	$316,000	$316,000
Lot Misc. Boiler Repairs/Modifications**	1	$250,000	$250,000
Sales and Construction Taxes (10%)			$118,600
Freight (7.5%)			$88,950
Purchased Equipment Costs, Subtotal			*$1,554,600*
Installation Costs			
Lot Foundation/Demolition	1	$10,000	$10,000
Structural, tons	2	$5,000	$10,000
Lot Equipment (Incl. port installation)	1	$500,000	$500,000
Lot Instrumentation/Electrical	1	$200,000	$200,000
Installation Costs, Subtotal			*$720,000*
	Total Direct Costs		$2,274,600
Indirect Costs			
Engineering, @ 7% of Direct Cost			$159,222
Construction & Field Expenses			--
Contractor			--
Owner's Cost, @ 5% of Direct Cost			$113,730
Consultant Services/Testing (Boiler Model)			120,000
Contingency, @ 10% of Direct Cost and Engineering			$243,382
	Total Indirect Costs		$636,334
	Total Capital Costs		$2,910,934

*operating and maintenance (OM) equipment estimates from Alstom Power

**One of the vendors indicated there may be a problem with flame impingement due to the extended flame from the burner and the small width of the furnace (19'). The cost to install shields or additional refractory can be quantified only after selection of vendor and burner.

Notes:

1. Principal vendors are Alstom Power and ABB-Ahlstrom
2. Guarantees:

(a) All willing to guarantee greater than 30% reduction (Alstom insistent on 50%–but no bond)
(b) Alstom willing to guarantee 50% for base-loaded boiler at 100% MCR
(c) All unwilling to guarantee any reduction when boiler operates below 70% MCR

Table E2 NO_x Monitor and Flow Monitor Installation Costs at Mill H

	Quantity	Price	Cost
Direct Costs			
*Purchased Equipment Costs**			
NO_x Monitor	1	$175,000	$175,000
Flow Monitor	1	$25,000	$25,000
Lot Stack Platform Materials	1	$55,000	$55,000
Sales and Construction Taxes (10%)			$25,500
*Freight (7.5%)***			$19,125
Purchased Equipment Costs, Subtotal			*$280,500*
Installation Costs			
Lot Foundation/Demolition	0	$0	$0
Structural, tons	4	$5,000	$20,000
Lot Equipment (Includes Stack Platform)	1	$55,000	$55,000
Lot Instrumentation/Electrical*	1	$120,000	$120,000
Installation Costs, Subtotal			*$195,000*
	Total Direct Costs		$475,500
Indirect Costs			
Engineering, @ 7% of Direct Cost			$33,285
Construction & Field Expenses***			
Contractor			
Owner's Cost, @ 5% of Direct Cost			23,775
Testing****			20,000
Contingency, @ 15% of Direct Cost and Engineering			$76,318
	Total Indirect Costs		$153,378
	Total Capital Costs		$628,878

*includes programming for NO_x Monitor ($50,000) and Flow Monitor ($15,000) from Thermo Environmental Instruments (formerly STI)

**not included in purchased equipment cost

***crane rental included in Stack Platform installation costs

****includes RATA, Compliance test, QA/QC Manual, and cal-gas

Notes:

1. Principal vendors are Automated Control Systems and Thermo Environmental.
2. Guarantees: all willing to guarantee satisfactory RATA and 95% uptime
3. Cost for Compliance test and RATA is $12,000 per Weston - assume 3.5 /year ($40,000).

Table E3 SNCR NO_x Control Installation Costs at Mill H

	Quantity	Price	Cost
Direct Costs			
Purchased Equipment Costs			
One Lot - (Urea) SNCR System	1	$515,000	$515,000
Structural Materials (Building)	1	$65,000	$65,000
Misc. Materials	1	$25,000	$25,000
Sales and Construction Taxes (10%)			$60,500
*Freight**			$23,000
Purchased Equipment Costs, Subtotal			*$665,500*
Installation Costs			
Lot Foundation/Demolition	1	$105,000	$105,000
Structural, tons	0	$5,000	$0
Lot Equipment Installation	1	$240,000	$240,000
Lot Instrumentation/Electrical	1	$105,000	$105,000
Installation Costs, Subtotal			*$450,000*
	Total Direct Costs		$1,115,500
Indirect Costs			
Engineering, @ 7% of Direct Cost			$78,085
Construction & Field Expenses			--
Contractor			--
Owner;s Cost, @ 5% of Direct Cost			$55,775
Consultant, Boiler Model			$100,000
Contingency, @ 10% of Direct Cost and Engineering			$119,359
	Total Indirect Costs		$353,219
	Total Capital Costs		$1,468,719

*Not included in purchased equipment cost

Notes:

1. Principal vendors are Nalco and Wheelabrator Fuel Tech
2. Guarantees:

(a) all willing to guarantee greater than 30% reduction in addition to LNB & OFA
(b) all willing to guarantee >50% for base loaded boiler at 100% MCR
(c) all unwilling to guarantee any reduction when boiler operates below 70% MCR
(d) none willing to guarantee ammonia slip

Table E4 SCR NO_x Control Installation Costs for Mill H

	Quantity	Price	Cost
Direct Costs			
*Purchased Equipment Costs**			
One Lot - SCR System	1	$2,000,000	$2,000,000
Misc. Materials (Includes CRI-Shell catalyst)	1	$900,000	$900,000
Sales and Construction Taxes (10%)			$290,000
*Freight***			$88,000
Purchased Equipment Costs, Subtotal			*$3,190,000*
*Installation Costs****			
Lot Foundation/Demolition	1	$205,000	$205,000
Structural, tons	55	$5,000	$275,000
Lot Equipment Installation	1	$440,000	$440,000
Lot Instrumentation/Electrical	1	$205,000	$205,000
Installation Costs, Subtotal			*$1,125,000*
	Total Direct Costs		$4,315,000
Indirect Costs			
Engineering, @ 7% of Direct Cost			$302,050
Construction & Field Expenses			54,000
Contractor			--
Owner's Cost, @ 5% of Direct Cost			$215,750
Contingency, @ 10% of Direct Cost and Engineering			$461,705
	Total Indirect Costs		$1,033,505
	Total Capital Costs		$5,348,505

*not included in purchased equipment cost

**Assume that cost for ammonia feed system will be same as estimated for urea feed and complete assembly supplied except building for liquid ammonia feed.

***Assume that it is possible to install modular SNR system and duct from ESP and from SCR back to use the existing stack. This project could require stack replacement, and the location could be affected by Boiler MACT which is not included in cost estimate.

Notes:

1. Principal vendors are Durr' and Pearless - Both offer fabricated modular systems that include ammonia feed, fan, ducting, SCR, and complete control systems.

2. Guarantees:

(a) All are willing to guarantee greater than 60% reduction, regardless of boiler load, but both recommend LNB and OFA installation for dependable benefit.

(b) Both will guarantee <3 ppm ammonia slip with additional (20%) catalyst.

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NATIONAL COUNCIL FOR AIR AND STREAM IMPROVEMENT

A REVIEW OF NO_X EMISSION CONTROL STRATEGIES FOR INDUSTRIAL BOILERS, KRAFT RECOVERY FURNACES, AND LIME KILNS

SPECIAL REPORT 99-01

APRIL 1999

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PRESIDENT'S NOTE

A final USEPA rule requiring 22 states and the District of Columbia to submit State Implementation Plan (SIP) revisions for achieving significant reductions in nitrogen oxides or "NO_x" was published in the October 27, 1998, *Federal Register*. The 22 states have until September 30, 1999, to prepare these revisions. All emission controls required by the states must be implemented by May 1, 2003. Electric utility plants and large fossil fuel–fired industrial boilers and turbines with over 250 x 10^6 Btu/hr heat input capacity are likely the main sources that would be subject to control requirements, although each state is free to formulate its own NO_x reduction program.

This report is intended to serve as a background document to assist member companies in responding to proposed SIP revisions, especially relative to the technical feasibility of implementing various NO_x control requirements. Besides providing a review of the fundamentals of NO_x formation during combustion, this report identifies limitations of applying NO_x control technologies developed primarily for fossil fuel–fired electric utility boilers to industrial boilers. Also, important differences in NO_x generation, emissions, and control resulting from the use of biomass and biomass-derived fuels are pointed out. A combination of factors including (1) the uniqueness of biomass boilers and kraft recovery furnaces, (2) the swing nature of most boilers used at forest products industry (FPI) manufacturing facilities, (3) the unproven nature of NO_x control technologies when applied to FPI combustion devices, and (4) the high cost of NO_x control for such units, makes it unlikely that any but the largest fossil fuel–fired boilers can be controlled for significant NO_x emission reduction in a cost-effective and technologically proven manner.

Ronald A. Yeske

April 1999

A REVIEW OF NO_X EMISSION CONTROL STRATEGIES FOR INDUSTRIAL BOILERS, KRAFT RECOVERY FURNACES, AND LIME KILNS

SPECIAL REPORT NO. 99-01
APRIL 1999

ABSTRACT

Fundamentals of NO_x formation are reviewed, especially as they apply to biomass and biomass-derived fuel combustion. Currently available technologies for industrial source NO_x emission control and their applicability to forest products industry combination and bark boilers, recovery furnaces, and lime kilns are discussed. Limitations of applying techniques suitable for base-loaded, fossil fuel–fired boilers to industrial boilers that operate in a swing mode are identified. Other limitations, such as those related to furnace design and dimensions, need to handle chemicals such as ammonia and urea at a mill site, uniqueness of wood combustion NO_x formation, and extremely high costs per ton of NO_x removed for most forest products industry boilers, are reviewed. Most kraft recovery furnaces already operate in a manner that results in minimal NO_x generation, and the existing practice of staged liquor combination is seen to be the most effective NO_x control strategy. Lime kiln NO_x emissions are extremely variable; the causes for this variation are unclear at the present time. The burning of stripper off-gases containing ammonia, while having the potential for NO_x formation by oxidation of the NH_3, is most likely not a source of additional NO_x emissions since combustion temperatures at the point of introduction of these gases are not high enough to bring about oxidation. Application of NO_x control strategies should take into account the predominantly "fuel NO_x" nature of biomass and biomass-derived fuel combustion units.

KEYWORDS

fuel NO_x, thermal NO_x, biomass, black liquor, staged combustion, wood residue, SCR, SNCR, combustion modification, LNB, OFA, costs, cost effectiveness

RELATED NCASI PUBLICATIONS

Technical Bulletin No. 646 (February 1993). *Emission factors for NO_x, SO_2 and volatile organic compounds for boilers, kraft pulp mills, and bleach plants.*

Technical Bulletin No. 636 (July 1992). *An analysis of kraft recovery furnace NO_x emissions and related parameters.*

Technical Bulletin No. 455 (April 1985). *Volatile organic carbon emissions from wood residue fired power boilers in the Southeast.*

Atmospheric Quality Improvement Technical Bulletin No. 111 (January 1981). *A study of nitrogen oxides emissions from large kraft recovery furnaces.*

Atmospheric Quality Improvement Technical Bulletin No. 109 (September 1980). *A study of wood-residue fired power boiler total gaseous non-methane organic emissions in the Pacific Northwest.*

Atmospheric Quality Improvement Technical Bulletin No. 107 (April 1980). *A study of nitrogen oxides emissions from lime kilns.*

Atmospheric Quality Improvement Technical Bulletin No. 105 (December 1979). *A study of nitrogen oxides emissions from kraft recovery furnaces.*

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TABLES

A REVIEW OF NO_x EMISSION CONTROL STRATEGIES FOR INDUSTRIAL BOILERS, KRAFT RECOVERY FURNACES, AND LIME KILNS

1.0 BACKGROUND

In the October 27, 1998, Federal Register, USEPA published a 183-page final rule requiring 22 eastern states to submit State Implementation Plan (SIP) revisions to reduce NO_x emissions. According to USEPA, the reductions would help minimize ozone formation resulting from the long range transport of one of ozone's major precursors, oxides of nitrogen. Ground-level ozone formation results from photochemical reactions involving NO_x and VOC emissions. States subject to the NO_x reduction requirements would be Alabama, Connecticut, Delaware, Georgia, Illinois, Indiana, Kentucky, Maryland, Massachusetts, Michigan, Missouri, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Virginia, West Virginia, and Wisconsin. For each of these states, USEPA has set a target reduction total amount of NO_x (in tons) for point sources which would have to be achieved by May 2003. NO_x emission reductions are based on the May 1 through September 30 ozone season.

The targets were established using sophisticated photochemical air quality simulation models. The models, which examined ozone formation over the eastern half of the U.S. during four different multi-day July ozone episodes (in 1988, 1991, 1993, and 1995), showed significant NO_x emission reductions would be effective in lowering peak ground level ozone concentrations over broad regions. Various emission reduction strategies which considered the type, location, and magnitude of both NO_x and VOC emission sources were examined with the models. In these evaluations, USEPA focused on the state-by-state NO_x emission reductions that would be needed for most areas in the eastern U.S. to achieve attainment with the 8 hour average ozone ambient air quality standard in the year 2007. Although 37 states were included in the modeling effort, USEPA concluded NO_x emissions from 15 of the states did not significantly impact maximum ozone concentrations in the region.

The due date for the 22 states to submit the SIP revisions to achieve these NO_x reductions is September 30, 1999. All controls required by the states must be implemented by May 1, 2003. A cost criterion of \$2000 per ton of NO_x reduction was used to determine which types of sources should be subject to control requirements. USEPA concluded that electric utilities and industrial boilers (>250 x 10^6 Btu/hr heat input capacity) should be the primary candidates for lowered NO_x emissions, and believes reductions from these sources are the most cost-effective that can be achieved, with average costs under \$2000 per ton of NO_x removed. Other types of sources, including smaller industrial boilers, pulp mill recovery furnaces, and lime kilns, were determined to likely have NO_x control costs exceeding \$2000/ton. However, it will be up to the individual states to decide on the specific control requirements for each stationary NO_x emission source.

In the 22 states, there are a large number of forest products manufacturing facilities, many of which operate combustion units that are potential candidates for NO_x controls. These facilities will need to ensure the technical feasibility and cost-reasonableness of any proposed new NO_x emission restrictions. Mills with large coal- and oil-burning boilers will especially need to begin examining the costs and technical feasibility of various NO_x control measures such as fuel switching, boiler combustion modifications, and add-on controls. Mills planning to install new boilers with heat input capacities of 100 x 10^6 Btu/hr or greater will also need to meet the recently promulgated New Source Performance Standards (NSPS) for NO_x emissions from these units. More details on this regulation are presented in Section 2.0.

This report provides a review of the fundamentals of NO_x formation during combustion and the currently available technologies for controlling industrial source NO_x emissions, especially as they pertain to the major NO_x emitting sources within the forest products industry (FPI) which include fossil fuel–, wood- and combination wood-fired boilers, kraft recovery furnaces, and lime kilns. Many FPI combustion units burn fuels of biomass origin. It is hoped that a clear understanding of what causes NO_x to form in these units and a review of currently available proven technologies for NO_x control for these units will be of help to mills facing possibly more stringent NO_x control measures in the future.

For industrial fossil fuel–fired boilers, a description of proven NO_x emission control techniques are extracted mainly from three sources: (1) a technical support document for proposed revisions to NSPS Subpart Db NO_x emission standards (USEPA 1997), (2) a USEPA summary of NO_x control technologies (USEPA 1992a), and (3) the Wisconsin Nitrogen Oxide Emission Reduction Cost Study report (WDNR 1989). The Subpart Db background document (USEPA 1997) provides a characterization of all industrial boilers as of 1995, discusses various nitrogen oxides emission control techniques for coal-, oil- and natural gas-fired industrial boilers and gives 1995 control cost estimates for applying proven NO_x control technologies to model industrial boilers. The WDNR study specifically recommends NO_x control technologies for five major industrial boiler categories: (1) stokers, coal-fired, (2) pulverized, coal-fired, (3) cyclones, coal-fired, (4) packaged, natural gas–fired, and (5) packaged, No. 6 oil-fired. This study also provides 1988 cost estimates for implementing NO_x emissions control for the five boiler categories. The control cost estimates for model industrial boilers given in the USEPA support document (USEPA 1997) and the recommendations for proven full-scale NO_x control technologies for industrial fossil fuel-fired boilers given in both the USEPA report and the WDNR report are reproduced here.

For forest products industry sources, including wood- and combination wood-fired boilers, kraft recovery furnaces, and lime kilns, the status and applicability of NO_x emissions control are discussed mainly based upon work carried out by NCASI and other researchers. As there exists only limited experience on NO_x emissions control for wood and combination wood-fired boilers, the discussion revolves mainly around the suitability of various NO_x control options currently available for fossil fuel combustion sources.

2.0 LEVEL OF NO_x CONTROL REQUIRED FOR NEW INDUSTRIAL BOILERS

It is perhaps instructive to first consider the level of NO_x control required to be implemented on a newly constructed boiler based on the recent NSPS. As mentioned above, USEPA revised NO_x emission limits contained in the Subpart Db NSPS which apply to industrial boilers with heat input capacities of 100 x 10^6 Btu/hr or greater in September 1998. Table 1 shows the revised emission limits for various types of boilers. These apply to all boilers for which construction started after July 9, 1997. All limits are 30-day rolling averages. Limits for natural gas and distillate oil–fired boilers were left essentially unchanged from the earlier NSPS Subpart Db standards promulgated on June 19, 1984, while limits for coal and residual oil were lowered significantly. The basis for the revised standards for coal- and residual oil–fired boilers is the application of combustion modifications and selective catalytic reduction (SCR) flue gas treatment, although USEPA claims that selective non-catalytic treatment (SNCR) may be sufficient for residual oil–fired units. Although no specific limits were promulgated for boilers firing wood residues, any boiler firing more than 10% of any fossil fuel on an annual basis is subject to the NO_x emission limit for the fossil fuel. Thus boilers firing coal or oil with wood would have a limit of 0.2 lb/10^6 Btu.

Table 1. NO_x Emission Factors and NSPS for Industrial Boilers
($>100 \times 10^6$ Btu/hr heat input)

	NO_x Emissions		
Fuel Type	AP-42[a] (lb/10^6 Btu)	1998 Subpart Db NSPS (lb/10^6 Btu)	Percent Reduction Required
Natural Gas	0.17 - 0.28[b]	0.10 - 0.20[c]	29 to 41
Residual Oil	0.28 - 0.45[b]	0.20	29 to 56
Distillate Oil	0.13 - 0.28	0.10 - 0.20[c]	23 to 29
Coal			
Pulverized	0.58-1.36[b]	0.20	66 to 85
Spreader Stoker	0.55	0.20	64
Fluidized Bed	0.61[d]	0.20	67
Mass Feed Stoker	0.30-0.38	0.20	33-47
Wood			
Fuel Cell	0.042[e] (0.00-0.17)	none	NA
Stoker Boilers	0.167 (0.07-0.40)	none	NA[f]
FBC Boilers	0.22	none	NA

[a] uncontrolled emission factors; used 1020 Btu/ft^3 gas, 150,000 Btu/gal oil, 12,500 Btu/lb coal & 4,500 Btu/lb as-fired wood in conversions
[b] lower factor for tangentially fired boilers
[c] lower factor for low and higher factor for high heat release rates
[d] bubbling bed
[e] NO_x emissions from fuel cells operating within the forest products industry are typically > 0.2 lb/10^6 Btu; a review of the AP-42 factors may thus be warranted
[f] note that wood-fired boilers firing > 10% fossil fuel are subject to limits for fossil fuel; also note that NO_x formation during wood combustion is primarily a function of wood nitrogen content

Table 1 also presents the uncontrolled NO_x emission factors for typical industrial boilers as given in USEPA's AP-42 document (USEPA 1996). The final column gives the range of expected percentage reductions in NO_x emissions from uncontrolled levels for boilers subject to the revised NSPS. Uncontrolled NO_x emissions from wood-fired boilers are also shown in Table 1 (USEPA 1996). Besides boilers firing biomass or fossil fuels, kraft recovery furnaces and lime kilns constitute the two other major sources of NO_x emissions in a typical kraft pulp mill. In NCASI Technical Bulletin No. 636 (NCASI 1992), NO_x emissions from several kraft recovery furnaces and lime kilns were reported to range from 0.08 to 0.20 lb/10^6 Btu for recovery furnaces (average 0.13 lb/10^6 Btu) and from 0.01 to 1.12 lb/10^6 Btu for lime kilns (average 0.27 lb/10^6 Btu), respectively.

3.0 FUNDAMENTALS OF NO_x FORMATION FROM FUEL AND LIQUOR COMBUSTION

This section provides a brief review of how oxides of nitrogen are formed during fuel and spent liquor combustion. Oxides of nitrogen formed during combustion comprise both NO and NO_2. Typically, nearly 90% to 95% of the total NO_x is NO due to kinetic limitations in the oxidation of NO to NO_2 (Bosch and Janssen 1988). USEPA's AP-42 document (USEPA 1996) suggests one use 95% for the NO fraction of all NO_x formed from fossil fuel combustion, the rest being NO_2. NO_x formed during combustion is a function of fuel composition, the operating mode, and the basic design of the boiler and combustion equipment. In industrial boilers and furnaces, NO_x is formed either as "fuel NO_x" or as "thermal NO_x."

Fuel NO_x is formed during the combustion of all fuels containing "bound" nitrogen. Bound nitrogen is contained in solid/liquid fuels such as coal, No. 6 oil, wood residues, black liquor, secondary and deinking sludges, and also in certain non-condensible gases containing nitrogenous substances such as ammonia. The fraction of bound nitrogen converting to NO_x depends on the fuel and its nitrogen content, a general trend being the lower the fuel nitrogen content, the higher the fraction converted to NO_x. Fuel NO_x is more sensitive to stoichiometry than to thermal conditions. The oxidation of fuel-bound nitrogen to NO is rapid and occurs on a time scale comparable to the energy release reactions during combustion (USEPA 1997). Approaches to reducing fuel NO_x therefore mainly focus on creating a "fuel-rich" zone and reducing the availability of oxygen. Traditional thermal treatments such as flue gas recirculation and water/steam injection do not reduce NO_x emissions from fuel nitrogen.

Thermal NO_x is formed at high temperatures by thermal fixation of molecular nitrogen in the combustion air. It is formed in the high temperature, post-flame region of a combustion system. Thermal NO_x is controlled by the reduction of temperature, oxygen and nitrogen concentrations, and residence time. Of these four factors, temperature is the most important. The rate of NO_x formation increases exponentially above about 2800°F flame temperature. Due to a high activation energy needed for a critical reaction in the thermal NO_x mechanism sequence, thermal NO_x formation is "time dependent" and only occurs after the energy release reactions have equilibrated (i.e., after combustion is "complete") (USEPA 1997). Thus, temperature quenching is a valid technique for thermal NO_x control. NO_x formation during combustion of natural gas and distillate oils occurs mainly by the thermal NO_x mechanism.

There is ample evidence in the literature suggesting NO_x formation in wood-fired boilers and wood-derived spent liquor-fired furnaces is predominantly by the fuel NO_x mechanism. During red alder combustion, Winter et al. (1989) observed that neither temperature (800°C, 1000°C, and 1200°C) nor moisture content of the wood fuel (10% and 45%) had any significant effect on the conversion of nitrogen evolved from the fuel to NO, leading to the conclusion that fuel N content and overall excess oxygen were the only key parameters controlling NO_x formation. However, empirical studies have found NO_x to vary inversely with fuel moisture content, although the magnitude of this correlation is less significant than with other operating conditions such as excess air, air staging and heat release rate (Stultz and Kitto 1992). Winter et al. (1989) also observed that NO emissions increased over threefold when red alder (0.76% N) or peat (1.18% N) was burned as compared with Douglas fir (0.18% N). Junge (1980) also concluded that NO_x formation in bark boilers is by the fuel NO_x mechanism. Tests in an industrial spreader-stoker pilot facility gave average emissions of 0.11 lb $NO_x/10^6$ Btu for Douglas fir (0.10% N) and 0.21 lb $NO_x/10^6$ Btu for eastern pine mix (0.22% N). The author concluded higher levels of fuel nitrogen will generate higher levels of NO_x for fixed combustion conditions.

In 1992, NCASI carried out a detailed investigation of kraft recovery furnace NO_x emissions and related parameters (NCASI 1992). This study concluded that temperatures in the lower furnace under normal operating conditions are likely not high enough to result in NO_x formation by the thermal NO_x mechanism pathway. NO_x formation by the fuel NO_x mechanism pathway is perhaps the most dominant mechanism just as for wood-fired boilers. Several other researchers (Nichols and Lien 1993; Nichols and Thompson 1993; Veverka et al. 1993; Martin et al. 1994; Adams et al. 1992; Osborne 1992) have since confirmed this finding that only a minor part of the NO in recovery furnace emissions is thermal NO, the majority being fuel NO or nitrogen oxide formed as a result of the oxidation of organically bound nitrogen in black liquor. Aho et al. (1994) studied the behavior of fuel nitrogen in black liquor combustion. From data on NO_x emissions from several full-scale recovery furnaces, they concluded that the one main variable in determining NO_x levels in a furnace is the liquor type. Combustion of birch liquors, which had the highest N content of four different liquors burned, gave the highest levels of NO_x. In a recent study, Forssen et al. (1997) conclude that (a) 70% to 80% of the black liquor N is released during devolatilization as gaseous nitrogen species, mainly ammonia and N_2, and the oxidation of NH_3 is perhaps the main contributor to the overall NO in normal black liquor firing, and (b) nearly 20% to 30% of the liquor nitrogen will be bound in the char residue much of which will remain as a reduced nitrogen species in the salt residue or smelt.

4.0 NO_X CONTROL TECHNIQUES FOR INDUSTRIAL FOSSIL FUEL-FIRED BOILERS

There are two principal methods of industrial boiler NO_x emissions control, viz., (1) combustion modification and (2) flue gas treatment. Combustion modifications are often associated with improving boiler performance. Flue gas treatment can occur both within the boiler and at several points along the path of the flue gas from the boiler to the stack. Other pre-combustion techniques such as fuel denitrogenation to reduce “fuel NO_x” have shown little promise.

4.1. Combustion Modifications

Combustion modifications are the most common, commercially available means of controlling NO_x emissions from fossil fuel-fired boilers. These can be brought about either by effecting relatively simple modifications of operating conditions or by incorporating more elaborate modifications of the combustion facility. Retrofit applications of NO_x controls by combustion modification usually proceed in several stages. First, fine tuning of combustion conditions by lowering excess air and adjusting burner settings and air distribution may be attempted. Next, minor modifications such as biased burner firing or burners out of service may be implemented. Finally, if further reductions are desired, other retrofits such as installation of overfire air ports, flue gas recirculation systems, and/or low-NO_x burners may be employed (USEPA 1992a).

Combustion modifications can be categorized under five areas: (1) low excess air (LEA), (2) staged combustion, (3) temperature reduction technologies, (4) low NO_x burners (LNB) and (5) in-furnace destruction.

4.1.1 Low Excess Air in the Flame Zone (LEA)

By reducing the amount of excess air, and therefore excess oxygen, in the local flame zone, moderate reductions in NO_x emissions may be possible. Operating the burners with low excess air (<5 % for oil and gas-fired boilers) results in lower NO_x emissions (both fuel and thermal NO_x) and higher boiler efficiencies. Unfortunately, low excess air operation has proven to yield only moderate NO_x reductions, if any (Wood 1994). Ten percent to 20% NO_x reduction is believed feasible by LEA for every 1% reduction in furnace O_2 levels (Makanski 1988). However, this technique is limited by the production of smoke, high CO emissions and possibly other problems within the boiler itself such as increased fouling and corrosion due to the reducing atmosphere (Jones, 1994). LEA is not in widespread use as a NO_x control technique for industrial boilers, but it is used for energy conservation (Jones 1994).

4.1.2 *Staged Combustion or Off-Stoichiometric Combustion*

Staged combustion or off-stoichiometric combustion is one of the oldest modification techniques for NO_x control. By diverting a portion of the total amount of air required through separate ports, generally located above the burners, a "fuel-rich" zone is created (also known as air staging [AS]). The fuel-rich conditions result in lower peak temperatures and thus, lower thermal as well as fuel nitrogen-generated NO_x. Staged combustion can be accomplished by various in-furnace techniques such as (a) overfire air (OFA), (b) burners out of service (BOOS) and (c) biased burner firing (BBF) or air/fuel mixing, each of which are described briefly below. These techniques are generally applicable to larger, multiple burner, combustion devices (Wood 1994).

(a) Overfire Air (OFA) — In OFA about 10% to 20% of the combustion air flow is directed to separate air ports located downstream of the burners. This modification is more attractive in original designs than in retrofit applications because of cost considerations, including cost of additional ductwork, furnace penetrations, extra fan capacity, and physical obstructions that make retrofit difficult in some installations (USEPA 1992a). When implemented, 15% to 30% NO_x reductions with OFA alone are expected (Makanski 1988). OFA is a very effective technique for NO_x reduction, especially for tangentially fired boilers (USEPA 1992a), and may be used with all fuels and most combustion systems, including stoker/grate units (Jones 1994). Operational problems resulting from OFA can include decreased combustion efficiency and deterioration of final steam conditions.

(b) Burners Out of Service (BOOS) — BOOS is a relatively simple technique used mostly in retrofit situations (suspension-fired coal and oil/gas-fired boilers) wherein multiple burners exist and fuel flow is blocked to an upper level of burners, allowing only air to pass through these. To avoid flame stability and vibration problems, the number of burners taken out of service should not $e_x$ceed 25% (USEPA 1991). Operational problems resulting from BOOS can include corrosion and soot/slag formation (USEPA 1991).

(c) Biased Burner Firing — In biased burner firing (BBF), also known as air/fuel mixing or fuel biasing, the furnace is divided into a lower, fuel-rich zone and an upper fuel-lean zone to complete the burnout. This technique has been proven only for oil/gas-fired utility boilers (Makanski 1988). A 20% reduction in NO_x can be expected.

4.1.3 *Temperature Reduction Technologies*

Several NO_x reduction technologies employ some method of reducing peak flame temperatures to minimize thermal NO_x formation. These include (a) flue gas recirculation (FGR), (b) reduced air preheat, (c) steam and water injection, and (d) decreased load.

(a) Flue Gas Recirculation (FGR) — In FGR, a portion of the combustion flue gas is brought into the combustion zone (up to 20% of the flue gas). The flue gas acts as a heat sink, lowering the combustion zone temperature, which results in lower thermal NO_x. High capital expenditures are necessary to install new ductwork, recirculation fans, devices to mix flue gas with combustion air, etc. Flue gas is typically taken from a stack breaching at about 300°F to 400°F and mixed with the secondary combustion air (wind box). As only thermal NO_x can be controlled by this technique, it is especially effective only in oil and gas-fired units. In fact, FGR is probably the most effective and least troublesome system for NO_x reduction for gas-fired combustors (Wood 1994). A 20% to 30% reduction in NO_x is expected (Makanski 1988). FGR is most effective when used in conjunction with air and/or fuel staging (Jones 1994). Once the favored option for industrial-boiler NO_x control, this is no longer the case due to a better understanding of the high capital costs and FGR fan and O&M costs involved in addition to loss of boiler efficiency (Jones 1994). FGR is more adaptable to new designs than as a retrofit application (USEPA 1992a).

(b) Reduced Air Preheat (RAP) — By lowering the amount of combustion air preheat the primary combustion zone peak temperature is lowered, hence resulting in lower thermal NO_x emissions. The energy penalty usually makes this option unfavorable (Yaverbaum 1979). A rule of thumb is a 1% efficiency loss for each 40°F reduction in preheat (Wood 1994). As in FGR, RAP only lowers thermal NO_x, and thus is economically attractive for only natural gas and distillate fuel oil combustion (USEPA 1992a).

(c) Steam and Water Injection — Flame quenching by the addition of steam or water in the combustion zone is an effective control technology for oil/gas-fired burners, although a significant energy penalty could ensue. Oil/water emulsions can realize a similar response as steam/water injection (Jones 1994) Suppression of NO_x formation up to 70% in gas turbines is believed feasible (Makanski 1988).

(d) Decreased Load — A reduction in the percentage of rated capacity leads to lower "volumetric heat release rates" in the boiler, and correspondingly lower flame temperatures and NO_x formation. Wasted load capacity is a definite disadvantage. Reduced mass flow can also cause improper fuel-air mixing during combustion, creating carbon monoxide and soot emissions (USEPA 1992a).

4.1.4 *Low NO_x Burners (LNB)*

LNBs are designed to mix fuel and air in a controlled pattern that sustains local fuel-rich regions, keeps the temperatures down and dissipates heat quickly. By controlling the mixing of the fuel and air, the combustion process can be initiated at the burner throat and the zone of complete combustion can be varied in the furnace chamber, resulting in elongated flames as compared to short, intense flames. Virtually all of the boiler and burner vendors have developed LNB for retrofit (Makanski 1988). Both staged air and staged fuel combustion principles are employed in LNBs. Combustion modification with LNBs is used in both gas/oil-fired and coal-fired units. A full LNB retrofit can be expected to reduce NO_x levels by about 50% (Makanski 1988). Flame containment, specifically sidewall and/or rear-wall flame impingement, is a challenge in the smaller boilers, particularly in a high-space-heat-release-rate package boiler.

Considered a modification of the low NO_x burner, *slagging combustors* involve high temperature combustion of coal in an air-deficient chamber. Ash is removed as a liquid slag and NO_x formation is suppressed. The gasified coal is then combusted in the existing furnace cavity. Owing to their similarity of combustion characteristics with that of cyclone-fired coal boilers (coal ash removed as liquid slag) slagging combustors are thought to be particularly good for retrofitting the latter (Makanski 1988).

4.1.5 *In-Furnace Destruction*

Also known as "reburning," "off-stoichiometric combustion" or "fuel staging," in this technique from 10% to 20% of the total fuel input is diverted to a second combustion zone downstream of the primary zone (Makanski 1988). The fuel in the fuel-rich secondary zone acts as a reducing agent, reducing NO formed in the primary zone to N_2. Low nitrogen containing fuels such as natural gas and distillate oil are typically used for reburning to minimize further NO_x formation. For example, the METHANE DeNOX reburning process uses the injection of natural gas together with recirculated flue gases (for enhanced mixing) to create an oxygen-rich zone above the combustion grate. Overfire air is then injected at a higher furnace elevation to burn out the combustibles (Loviska et al. 1998). This process is claimed to yield between 50% and 70% NO_x reduction and be suitable for all solid fuel-fired stoker boilers (coal, biomass, municipal solid waste, RDF, etc.). However, it has only been demonstrated on one municipal waste combustor (Abbasi et al. 1998) and one 60 MWe stoker coal-fired unit (Loviska et al. 1998) in the United States. The Institute of Gas Technology (IGT), which developed this process, has plans to apply METHANE DeNOX to a pulp and paper mill wood residue-fired boiler while increasing the feed of waste treatment plant residuals to the boiler from 1.5% to 5.0% of heat input.

4.2 Flue Gas Treatment

The selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) processes are among the only proven, viable post-combustion flue gas treatment processes. Several other more advanced processes are currently being developed, some awaiting results of pilot stage results and others awaiting the passage of more stringent NO_x control laws whereby their full-scale use can be put to the test.

4.2.1 *Selective Non-Catalytic Reduction (SNCR)*

SNCR involves the injection of urea, ammonium hydroxide, anhydrous ammonia, or aqueous ammonia into the furnace exit region where the flue gas is in the range of 1,600°F to 1,900°F (USEPA 1997). NO_x is reduced to N_2 and H_2O. One concern about this process is its ability to perform adequately under changing load and fuel conditions (Jones 1994). The thermal DeNO_x process relies on the injection of ammonia and the NO_xOUT process relies on the injection of urea into the boiler. Both ammonia and urea bring about gas phase reduction of NO_x to nitrogen. A portion of the NO reduction by SNCR systems, usually around 5%, is due to transformation of NO to N_2O, which is a global warming gas (USEPA 1998).

(a) Thermal DeNO_x — The thermal DeNO_x process, developed and marketed by Exxon Research and Engineering Company (Hurst 1983), selectively reduces NO_x to molecular nitrogen and water by using ammonia injection into the air-rich flue gas in the temperature range of 1600°F to 2200°F, temperatures typically found in the upper portions of the furnace (superheater section or before air preheater). The actual chemical mechanism of the process is quite complex, involving 31 significant chemical reactions (Hurst 1983). NO_x reduction as high as 60% to 70% has been achieved in some industrial applications. The reduction efficiency is affected by the NH_3 feed rate relative to NO_x concentrations, by the degree of flue gas thermal stratification in the ammonia injection section, and by the flue gas residence time within the appropriate temperature window.

The reaction predominates around a temperature of 1740°F (USEPA 1981). For temperatures above 2000°F, the injected ammonia is oxidized to NO, and for temperatures below about 1560°F the reaction proceeds slowly and the NO reduction falls off drastically, resulting in significant ammonia slippage (USEPA 1981). The ammonia must be diluted with air or steam to allow for good mixing. The injection is usually accomplished by using a multiport injection grid to allow for varying flue gas temperatures due to boiler load swings. Problems with NH_3 injection include ammonia slippage, fouling of air preheater surface by ammonium sulfate/biosulfate formation and maintaining optimum reaction temperatures (USEPA 1981).

(b) NO_xOUT — Research into the injection of urea (solid or aqueous solution) in a manner similar to ammonia was first carried out by the Electric Power Research Institute (DePriest et al. 1989). Known as the NO_xOUT process, it is receiving increased attention on account of both the reduced cost and reduced danger of handling urea as compared with ammonia. Also, it is believed that urea/water injection parameters can be more easily matched to furnace temperature, providing better load-following capability and resulting in reduced hardware requirements such as injection grids (Makanski 1988). The NO_xOUT process is based upon the following chemical reaction that occurs in the temperature range of 1700°F to 2000°F (Muzio and Anand 1976).

$$2\,NO + NH_2CONH_2 + 1/2\,O_2 \rightarrow 2\,N_2 + CO_2 + 2\,H_2O \qquad \text{(i)}$$

The problems of ammonia slippage and heat transfer surface fouling with byproduct formation also exist with the NO_xOUT process.

Six factors directly affect the performance of urea- or NH_3-based SNCR systems (USEPA 1997). These are inlet NO_x level, temperature, mixing, residence time, reagent-to-NO_x ratio, and fuel sulfur content. Lower inlet NO_x concentrations reduce the reaction kinetics and hence the achievable NO_x emissions reductions. As mentioned above, temperatures below the desired window result in ammonia emissions (slip), and temperatures above the desired window result in NH_3 being oxidized to NO_x. Mixing becomes an important consideration in regions distant from an injection nozzle where the level of turbulence is reduced and stratification of the reagent and flue gas will probably be a greater problem especially at low boiler loads (USEPA 1997). Residence time becomes important to allow the desired reactions to go to completion. Small, packaged, watertube boilers and boilers with varying steam loads are therefore difficult applications for SNCR (USEPA 1997). As higher than the theoretical NH_3:NO_x ratios are generally required to achieve desired NO_x emission reductions, a trade-off exists between NO_x control and the presence of NH_3 in the flue gas. Finally, in the case of high sulfur fuels, excess NH_3 can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit on downstream equipment leading to plugging and reduced heat transfer efficiencies.

4.2.2 *Selective Catalytic Reduction (SCR)*

The SCR process also uses ammonia injection but the reduction reactions are carried out on the surface of a catalyst operating at temperatures between 450°F and 750°F. The following overall reactions are known to occur on the catalytic surface:

$$4\,NH_3 + 4\,NO + O_2 \xrightarrow{\text{catalyst}} 4\,N_2 + 6\,H_2O \qquad \text{(ii)}$$

$$8\,NH_3 + 6\,NO_2 \xrightarrow{\text{catalyst}} 7\,N_2 + 12\,H_2O \qquad \text{(iii)}$$

The active compound which promotes the NH_3- NO_x reaction may be composed of a precious metal (e.g., Pt, Pd), a base metal oxide, or a zeolite (USEPA 1997). Precious metal catalysts are used in clean fuel applications and at lower temperatures than the base metal oxide or zeolite catalyst. The most common base metal oxide catalysts are vanadium/titanium based, with V_2O_5 as the active material and TiO_2 as the support material. The zeolite catalysts are stable over a wider temperature window than other types of catalysts. Optimum NO_x reduction occurs at catalyst bed temperatures between 600°F and 750°F for conventional (vanadium or titanium-based) catalyst types, and between 470°F and 510°F for platinum-based catalysts (USEPA 1991). An ammonia to NO ratio of 1:1 has typically reduced NO_x by 80% to 90% with a leak rate of less than 20 ppm (USEPA 1981). The reactor is usually located between the boiler and air preheater. NO_x control efficiencies are typically in the range of 70% to 90%, depending on type of catalyst, amount of NH_3 injected, the initial NO level, and the age of the catalyst.

The performance of an SCR system is also affected by six factors (USEPA 1997). These are NO_x level at SCR inlet, flue gas temperature, NH_3-to-NO_x ratio, fuel sulfur content, gas flow rate, and catalyst condition. For SCR, when inlet NO_x concentrations fall below 150 ppm the reduction efficiencies decrease with decreasing NO_x concentrations (USEPA 1997). Each type of catalyst has an optimum operating temperature range. Temperatures below this range result in ammonia emissions (slip) and temperatures above the desired range result in NH_3 being oxidized to NO_x. For up to about 80% NO_x reduction efficiencies, a 1:1 NH_3: NO_x ratio is sufficient. For higher efficiencies, higher reagent to NO_x ratios are required which may result in higher NH_3 slip. In the case of high sulfur fuels excess NH_3 can react with sulfur trioxide to form ammonium sulfate salt compounds that deposit and foul downstream equipment. SCR application experience in the case of medium-to-high sulfur fuels is limited. For a given flue gas flow rate, the catalyst structural design should be chosen so that the residence time needed for the reduction reactions to take place on the catalyst surface is achievable. Catalysts degrade over time due to poisoning, fouling, thermal stress, erosion by particulate, etc. NO_x removal decreases as the catalyst gets deactivated. Catalysts are a major component of the cost of SCR.

SCR is considered a high-efficiency removal device. Today, SCR has become a common feature of new gas-turbine cogeneration and combined cycle systems in the US (Jones 1994). Major problems with SCR processes include corrosion due to higher flue gas acid dew points, and formation of solid ammonium sulfate and ammonium bisulfate, particularly in high sulfur oil-fired or coal-fired boilers. These could deposit on the air preheater surface to reduce heat transfer efficiencies. Ammonia slippage is also a potential problem. Due to poisoning by trace metals or erosion by fly ash, catalysts lose activity over time. Although a proven technology for larger units (>20 MW), it is not in widespread use for smaller industrial boilers. In fact, as of 1995 none of the industrial boilers in the United States was equipped with the SCR process (USEPA 1997).

4.2.3 *Other FGT Processes - SO_2-NO_x Removal*

DePriest et al. (1989) reviewed several other flue gas treatment processes that were under consideration nearly a decade ago. These processes typically had the goal of finding lower cost alternatives to SCR for NO_x control and conventional FGD for SO_2 control. These technologies, primarily targeted at removing both SO_2 and NO_x from the flue gas stream, may be classified under six categories. To date, none of these technologies has resulted in full-scale applications intended for significant NO_x reductions from combustion sources.

(a) Solid Adsorption/Regeneration — These processes use a recirculating solid sorbent material to remove SO_2 and NO_x from the flue gas. They include (1) the UOP/PETC Fluidized-Bed

Copper Oxide Process, (2) the Rockwell Moving Bed Copper Oxide Process, (3) the NOXSO process, (4) the Mitsui/BF Activated Coke Process, (5) the Sumitomo/EPDC Activated Char Process, and (6) the Sanitech Nelsorbent SO_2/NO_x Control Process.

(b) Irradiation of the Flue Gas — High-energy electrons from electron accelerators, pulsed corona discharge, UV and microwave radiation are used in these processes to produce reactive species and subsequently oxidize SO_2 and NO_x to their respective acids. Usually located after particulate control devices these processes often involve ammonia injection after the reactor, with ammonium compounds separated in a second control device.

(c) Wet Scrubbing — These processes either oxidize the NO to NO_2 and then scrub with an absorbing medium, or use additives to enhance solubility of NO in the medium. Processes in this category include (1) the Saarberg-Holter Iron Chelate Scrubbing Process, (2) the Argonne/Dravo ARGONNOX Process, (3) the Dow Electrochemical Regeneration Process, (4) the Dow Polychelant/ Ultrafiltration Process, (5) the PETC Electrodialysis Process, and (6) the California (Berkeley) Ferrous Cysteine Process.

(d) Gas/Solid Catalytic Operations — In these processes hot flue gases prior to the air preheater are passed through a fixed bed catalytic reactor. The NO_x is reduced to N_2, while the SO_2 may be converted to either sulfuric acid or sulfur. Included are (1) the Haldor Topsoe WSSA-SNO_x Process, (2) the Degussa DESONOX Process, (3) the B&W $SO_x/NO_x/RO_x/BO_x$ (SNRB) Process, (4) the Parsons Flue Gas Cleanup Process, and (5) the Lehigh University Low-Temperature SCR Process.

4.3 Applicability of Proven NO_x Control Technologies for Utility Boilers to Industrial Boilers

Much of the operating experience gained on fossil fuel-fired boiler NO_x emissions control has been on utility boilers. As of 1995, industrial boilers subject to the earlier Subpart Db NSPS NO_x limits included eight coal-fired fluidized bed combustors (FBC), four oil-fired boilers, and 31 natural gas-fired boilers (USEPA 1997). Five of the coal-fired FBCs used only combustion controls (CC), while the remaining three were equipped with SNCR. Three of the four oil-fired boilers used CC while the fourth controlled NO_x by restricting operating hours. NO_x emission controls on the 31 natural gas-fired boilers ranged from good combustion practice to using SNCR. None used SCR.

4.3.1 *Applicability of Combustion Modification NO_x Control Technologies*

Industrial boilers typically operate with widely varying steam loads. On average, across the industrial spectrum, a mean capacity utilization factor of 45% to 55% is estimated (CIBO 1993). Even recently installed cogeneration and independent-power facilities are predicated on dispatch schedules dictated by the utility purchasing the power (Jones 1994). NO_x reduction measures are particularly difficult to implement in small, low-capacity facilities because (a) residence time is limited and often inadequate for applying overfire air (OFA) without excessive loss of thermal efficiency or induced smoking, (b) relatively small furnace dimensions limit combustion modifications that increase flame length and tend to cause the flame to impinge on tube walls, (c) peak boiler efficiency and minimized NO_x emissions occur close to minimum flue-gas O_2 content, which is at the threshold of smoke or combustible-emissions formation, (d) steam is used far more effectively in industrial applications than in conventional electric utility plants and consequently, basing emission limits on boiler heat input or volume of flue gas does not properly credit efficiency (Jones 1994).

The Council of Industrial Boiler Owners prepared a NO_x RACT (Reasonably Available Control Technologies) guidance document (CIBO 1993) which summarized the problems associated with developing RACT rules for industrial boilers as follows:

- The industrial boiler population is diverse – no specific type is prevalent.
- There is very little hard NO_x emissions data from existing industrial systems.
- The variability of emissions from a unit, type system or class of units, can be extreme.
- Projection of system trends is impractical; therefore, emissions may have to be considered on a unit by unit basis.
- Most industrial stoker fired units installed prior to 1987 were equipped with only one or two rows of overfire ports, and a maximum of 10% to 20% total air, an arrangement designed to optimize combustion efficiency, *not* to control NO_x emissions.
- Bottom-supported stoker units are virtually impossibly to retrofit with a new overfire air arrangement.
- Inherent system variability requires that a 30-day rolling average be the standard for industrial boilers.

In written comments to the Maine Department of Environmental Protection, Sonnichsen (1994) of CARNOT included the following reservations when applying utility NO_x control experience to industrial boilers:

- The greatest difference between utility boiler operations and power boiler operations is the fluctuating steam demand characteristic of pulp and paper mill power boiler operations. Normally, power boilers continuously adjust fuel firing rates and excess air levels. Even with the most sophisticated combustion controls, it is neither practical nor safe to continuously maintain minimum levels of excess air. Consequently, power boilers have higher NO_x emissions.
- Fuel biasing on an industrial boiler subject to rapid and excessive load swings could result in too rich or lean firing conditions, which can lead to flame stability problems and explosive conditions.
- Windbox flue gas recirculation (FGR) could be considered for use on oil-fired boilers. Its application, however, can be limited by (1) the windbox and boiler fans' capacities, (2) increased boiler bank tube wall erosion, and (3) the potential for severe damage from changes in convection heat transfer and boiler water circulation patterns.
- The application of low NO_x burners (LNB) is often limited by the longer flames produced as a consequence of improved air distribution control. While there is generally ample room for LNB flames in utility furnaces, their use on the smaller power boilers can result in flame impingement on furnace walls, leading to tube wall overheating and mechanical failure. Flame impingement can also result in premature flame quenching and increased soot and CO emissions.

- Unlike utilities, which can specify the nitrogen content of their large oil purchases, most mills cannot make this specification.

Even within the family of industrial boilers there are considerable differences in the design of various types of boilers and therefore the applicability of certain NO_x control technologies. For example, considerable differences exist in the heat removal rates between a grate-fired boiler for wood residue or coal combustion and a packaged boiler for oil or gas combustion. The grate boiler is designed for staged combustion since a large amount of the combustion air is introduced above the grate fire. Also, the size of the grate furnace compared to a similar packaged boiler is two to three times greater. The net result is that there is more heat absorption in a grate-fired boiler resulting in lower thermal NO_x formation. When applied to packaged boilers, both air staging and flue gas recirculation, recommended NO_x control techniques for oil and gas combustion, will increase the burner flame length requiring added furnace length to avoid flame impingement on the furnace walls.

4.3.2 *Applicability of SNCR NO_x Control Technology*

As previously mentioned, the use of the SNCR process in a packaged boiler would require having access to a temperature window between about 1700°F and 2000°F in which to inject the ammonia or urea. Controlling flue gas temperatures in the convective section of a package or even grate boiler over the entire range of operating loads the boiler is expected to experience will be very difficult to achieve. Boilers in the pulp and paper industry rarely operate under base loaded conditions. Consequently, the location of the desired temperature window is expected to change constantly. Accurate, instantaneous temperature measurement, as well as the ability to accurately adjust the location of the injection nozzle, would be necessary. Ammonia slip would be a recurring problem associated with the application of the SNCR process to industrial boilers with fluctuating loads.

4.3.3 *Applicability of the SCR NO_x Control Technology*

Since the selective catalytic reduction process also involves the injection of ammonia within a fairly narrow range of temperatures, albeit a lower range than for the SNCR process, the problems described for the SNCR process relative to fluctuating loads in pulp mill industrial boilers and resulting ammonia slip are equally relevant here. In addition, an important factor that further restricts the use of the SCR process to most industrial boilers is the large loss in energy efficiency that would result from the need to reheat the exhaust gases. Exhaust gases exiting the economizer sections of these boilers are typically in the range of 250°F to 350°F, while the desired temperature range for the SCR process is between 450°F and 750°F.

4.4 Proven Full-Scale NO_x Control for Industrial Fossil fuel–fired Boilers – The WDNR Study

As part of the NO_x Emission Reduction Cost Study (WDNR 1989), the Wisconsin Department of Natural Resources conducted a comprehensive study of industrial boiler NO_x control, including both technical and economic evaluations. Only technologies proven in full-scale demonstration (mostly utilities) were considered. The results of this study may be relevant even today, and hence they are presented here. Industrial boilers in Wisconsin were found to belong to one of the following five major categories, viz., (1) coal-fired stokers, (2) pulverized coal, (3) coal-fired cyclones, (4) packaged, natural gas-fired, and (5) packaged, No. 6 oil-fired. The criteria for choosing technologies for specific boiler applications were based upon (a) evaluations of field demonstrations and (b) cost effectiveness of process implementation.

A summary of optimum NO_x control technologies, NO_x removal or reduction capabilities, commercial availability and any associated problems with these technologies for the five boiler categories considered in the WDNR study (WDNR 1989) is shown in Tables 2 to 6, respectively. In all cases, although the SCR process offered the highest percent NO_x reduction, for reasons previously mentioned in this paper, the SCR process is not yet considered to be a cost-effective and demonstrable technology in the United States, at least not for the smaller industrial boilers.

Table 2 shows that a combination of FGR and OFA is effective for moderate NO_x reduction in stoker-fired boilers. Further reductions could be achieved by installing the thermal $DeNO_x$ or NO_xOUT process. On account of the difficulty in modifying the combustion chamber, reburning with natural gas is the only combustion modification option feasible with cyclone-fired coal boilers. Fifty percent to 60% NO_x reduction with reburning and 60% to 70% reduction with the two SNCR processes are feasible (Table 3). Low NO_x burners are the leading technologies for pulverized coal boilers (Table 4). The SNCR processes offer 60% to 70% reduction capability, only marginally better than boilers fitted with the LNBs (about 50%). LNB with FGR offers the highest percent reduction of NO_x for natural gas-fired packaged boilers (Table 5). Finally, Table 6 shows that a new NO_x reduction technology, low NO_x with relatively large substoichiometrically fired precombustor, offers the best promise for No. 6 fuel oil–fired, industrial boilers.

In its technical support document to the proposed revisions to the Subpart Db NO_x (USEPA 1997), USEPA summarizes the types of NO_x controls demonstrated or applicable for new fossil fuel–fired industrial boilers. This summary is presented in Table 7. According to USEPA, low NO_x burners (LNB) and LNB with overfire air (OFA) are applicable to all conventional (pulverized) coal-fired, gas-fired and oil-fired boilers, air staging is applicable to coal-fired fluidized bed combustors (FBC) and spreader stokers (SS), flue gas recirculation (FGR) is applicable to natural gas- and oil-fired industrial boilers, and flue gas treatment techniques such as SNCR or SCR are applicable to all fossil fuel-fired units. However, in the United States, SNCR has been applied to only a few industrial boilers and SCR has been applied to none.

Table 2. NO_x Control for Stoker-fired Industrial Boilers
(Bituminous or Sub-bituminous Coal) (WDNR 1989)

Control Techniques	NO_x Reduction Percent	Commercial Availability and Comments
FGR	40 to 45	Available. Increased operating cost and significant capital cost.
LEA	10 to 20	Available. Baseline O_2 levels of 9% are reduced to 6.5 to 7%. Danger of grate overheating, clinker formation, corrosion, high CO emission. Can be combined with OFA and FGR.
OFA	5 to 10	Available. Danger same as LEA. Could be applied very effectively with FGR and LEA.
NH_3 injection	60 to 70	Available. Problems – NH_3 slip, $(NH_4)_2SO_4$ deposit. Multiple injection ports needed for swinging loads –High operational cost. Narrow temperature window of operability.
Urea injection	60 to 70	Available. Same as NH_3 injection. Wider temperature window than ammonia injection.
SCR	80 to 90	Available. Extremely high capital and operating costs. NH_3 slip and $(NH_4)_2SO_4$ deposit on catalyst surfaces. Catalyst deactivation by coal contaminants.

Notes: 1. NO_x emissions for stokers are lower than for pulverized coal. Both chain grate spreader stoker and underfeed stokers were considered.
2. A combination of FGR and OFA is effective for moderate reduction.
3. The thermal $DeNO_x$ and NO_xOUT processes can be added to augment FGR and OFA.

Table 3. NO_x Control for Cyclone-Coal-Fired Industrial Boilers (WDNR 1989)

Control Techniques	NO_x Reduction Percent	Commercial Availability and Comments
Reburning natural gas	50 to 60	Under development. Up to 30% of coal heat input replaced by natural gas. Danger of unburned CO and HC in the flue gas.
NH_3 injection	60 to 70	Available. Problems – NH_3 slip, $(NH_4)_2SO_4$ deposit. High operational cost. Narrow temperature window.
Urea injection	60 to 70	Available. Same as NH_3 injection.
SCR	80 to 90	Available. Extremely high capital and operating costs. Problems include NH_3 slip, $(NH_4)_2SO_4$ deposit on catalyst surfaces and catalyst deactivation by coal contaminants.

Notes: 1. Cyclone boilers are characterized by high uncontrolled NO_x emissions.
2. Combustion chamber design modifications are very difficult to accomplish.

Table 4. NO_x Control for Pulverized-Coal-Fired Industrial Boilers (WDNR 1989)

Control Techniques	NO_x Reduction Percent	Commercial Availability and Comments
LNB	50	Commercial available. Relatively high capital investment for boiler modifications.
Reburning	50 to 60	Under development. Danger of unburned natural gas, CO and HC in the flue gas.
NH_3 injection	60 to 70	Available. NH_3 slip, $(NH_4)_2SO_4$ deposit. High operational cost. Narrow temperature window.
Urea injection	60 to 70	Available. Same as NH_3 injection.
SCR	80 to 90	Available. Extremely high capital and operating costs. Problems include NH_3 slip, $(NH_4)_2SO_4$ deposit on catalyst surfaces and catalyst deactivation by coal contaminants.

Note: Leading technologies for pulverized coal boilers (wall and tangentially fired) are low NO_x burners.

Table 5. NO_x Control for Natural Gas-Fired, Packaged Industrial Boilers (WDNR 1989)

Control Techniques	NO_x Reduction Percent	Commercial Availability and Comments
LNB W/LEA	5 to 10	Commercially available. Danger of unburned HC and CO in the flue gas.
LNB W/FGR	60 to 75	Commercially available. Increased operational cost for fans. Increased flame length may cause flame instability and affect super-heater performance.
LNB W/AS	10 to 15	Commercially available. Danger of unburned HC and CO in flue gas. Possible flame impingement.
LNB W/fuel	15 to 20	Commercially available. Danger of unburned HC and staging CO. Increased flame length.
NH_3 & urea	50 to 60	Commercially available. Several boiler design constraints to apply urea and NH_3 injection for package boilers.
SCR	80 to 90	Available. High capital and operating cost.

Note: NO_x emissions are lower as thermal NO_x is the only formative mechanism.

Table 6. NO_x Control for No. 6 Oil–Fired, Industrial Boilers (Packaged, Watertube) (WDNR 1989)

Control Techniques	NO_x Reduction Percent	Commercial Availability and Comments
LNB W/LEA	5 to 10	Commercially available. Danger of unburned HC and soot formation. Flame instability.
Low NO_x with relatively large substoichiometrically fired precombustor	70	In a final development state. Tested in full scale. Requires space in front of the boiler.
NH_3 & urea injection	50	Commercially available. Several boiler design constraints to apply urea and NH_3 injection for package boilers.
SCR	70 to 80	Commercially Available. SCR Difficulties include plugging and catalyst deactivation.

Note: NO_x emissions are greater from residual oil compared with distillate oil and natural gas boilers.

Table 7. NO_x Emission Control Technologies For New Fossil Fuel Industrial Boilers (USEPA 1997)

NO_x Control Options	Fuel Applicability
Combustion control techniques	
Low NO_x burners for conventional boilers	Coal, natural gas, oil
Low NO_x burners + overfire air for conventional boilers	Coal, natural gas, oil
Air staging for fluidized bed combustion boilers	Coal
Air staging for spreader stoker boilers	Coal
Flue gas recirculation	Natural gas, oil
Flue gas treatment techniques	
Selective noncatalytic reduction	Coal, natural gas, oil
Selective catalytic reduction	Coal, natural gas, oil

5.0 USEPA CONTROL COST DATA FOR INDUSTRIAL FOSSIL FUEL–FIRED BOILERS

In the background technical document for the revised Subpart Db NO_x emissions standards, USEPA also presented control technology costs for instituting various types of NO_x emissions control on fossil fuel–fired industrial boilers (USEPA 1997). Summary annualized costs and incremental cost effectiveness ranges from this document are reproduced for various model boilers in Tables 8 and 9, respectively. Table 8 shows the cost of installing combustion controls for NO_x emissions on industrial fossil fuel–fired boilers ranges from 0% to 2% of the net cost of generating steam in the boiler. When combustion controls are augmented by SNCR, the total cost rises to between 4% and 16% of the steam cost. Finally, when SCR is used along with combustion controls the total cost increases appreciably to between 10% and 48% of the steam cost. Table 9 gives estimates for incremental cost effectiveness in \$/ton NO_x removed. When applying SCR to industrial boilers after combustion controls have been implemented, the incremental cost effectiveness estimates are seen to be extremely high, ranging from \$5,900 to \$49,800 per ton of NO_x removed. Incremental cost effectiveness estimates for applying SNCR to boilers after combustion control implementation are also high, ranging from \$1,720 to \$32,140 per ton of NO_x removed. In the July 1997 *Federal Register* proposal (*FR* 62 [131] 36948-36963), USEPA explains the wide range in the cost and cost effectiveness estimates as follows: "The main differences between industrial steam generating units and utility steam generating units are that industrial steam generating units tend to be smaller and tend to operate at lower capacity factors. The differences between industrial and utility steam generating units would be reflected in the cost impacts of the various NO_x control technologies. Smaller sized and lower capacity factor units tend to have a higher cost on a per unit output basis."

Table 8. Summary of Annualized Costs for Model Boilers[a] (EPA 1997)

Fuel Type	Furnace Type[b]	Size (MM Btu/hr)	CC[c]		CC + SNCR[c]		CC + SCR[c]	
			$/yr	%	$/yr	%	$/yr	%
Coal	PC	250	40,040	1	286,530	9	997,740	33
		500	59,020	1	384,460	6	1,605,070	27
		1,000	87,010	1	538,850	4	2,756,820	23
	FBC	100	0	0	173,170	14	NA	NA
		250	0	0	227,480	8	NA	NA
		500	0	0	287,410	5	NA	NA
		1,000	0	0	375,780	3	NA	NA
	Spreader Stoker	100	0	0	184,580	15	583,440	48
		250	0	0	256,000	8	960,920	32
		500	0	0	344,540	6	1,551,210	26
Residual Oil	Field-erected Watertube	100	23,970	2	197,060	16	461,860	38
		250	40,040	1	265,600	9	668,940	22
		500	59,020	1	341,770	6	972,550	16
		1,000	87,010	1	453,320	4	1,522,790	13
	Packaged Watertube	100	23,970	2	197,060	16	461,860	38
		250	40,040	1	265,600	9	668,940	22
Distillate Oil/ Natural Gas	Field-erected Watertube	100	0	0	168,910	14	418,880	35
		250	0	0	215,110	7	581,250	19
		500	0	0	261,830	4	818,200	14
		1,000	0	0	324,470	3	1,245,120	10
	Packaged Watertube	100	23,970	2	194,400	16	443,210	37
		250	40,040	1	258,940	9	622,310	21

[a] The data presented represents annualized costs for the range of boiler sizes at a capacity factor of 0.30. Annualized cost expressed as a percentage of steam cost; steam cost based on $6 per 1000 lb steam; and 1,300 Btu of heat input per lb of steam generated.

[b] PC = Pulverized Coal; FBC = Fluidized Bed Combustion; [c] CC = Combustion Control; SCR = Selective Catalytic Reduction; SNCR = Selective Non-Catalytic Reduction

Table 9. Model Boiler Incremental Cost Effectiveness Ranges[a] (USEPA 1997)

Fuel Type	Furnace Type[b]	Control Technology Comparisons[c]	Incremental Cost Effectiveness ($/ton)
Coal	PC	CC vs. Baseline	240 - 440
		CC + SNCR vs. CC	1,720 - 3,375
		CC + SCR vs. CC	6,350 - 9,110
		CC + SCR vs. CC + SNCR	14,070 - 18,040
	FBC	CC vs. Baseline	0
		CC + SNCR vs. CC	2,860 - 13,180
		CC + SCR vs. CC	NA[d]
		CC + SCR vs. CC + SNCR	NA
	Spreader Stoker	CC vs. Baseline	0
		CC + SNCR vs. CC	2,100 - 5,620
		CC + SCR vs. CC	5,900 - 11,100
		CC + SCR vs. CC + SNCR	12,250 - 20,240
Residual Oil	Field-erected Watertube	CC vs. Baseline	740 - 2,030
		CC + SNCR vs. CC	2,930 - 13,870
		CC + SCR vs. CC	7,190 - 21,920
		CC + SCR vs. CC + SNCR	14,280 - 35,350
	Packaged Watertube	CC vs. Baseline	640 - 960
		CC + SNCR vs. CC	7,230 - 13,870
		CC + SCR vs. CC	12,600 - 21,920
		CC + SCR vs. CC + SNCR	21,540 - 35,350
Distillate Oil/ Natural Gas	Field-erected Watertube	CC vs. Baseline	0
		CC + SNCR vs. CC	6,170 - 32,140
		CC + SCR vs. CC	14,180 - 49,800
		CC + SCR vs. CC + SNCR	29,190 - 79,250
		CC vs. Baseline	2,030 - 3,040
	Packaged Watertube	CC + SNCR vs. CC	11,110 - 21,620
		CC + SCR vs. CC	18,460 - 33,240
		CC + SCR vs. CC + SNCR	30,730 - 52,600

[a] The data presented represents the incremental cost effectiveness at a capacity factor of 0.30 for the range of boiler sizes 250, 500 and 1,000 MMBtu/hr for PC boilers; 100, 250, 500 and 1,000 MMBtu/hr for FBC and field-erected boilers; 100, 250 and 500 MMBtu/hr for spreader stoker boilers; and 100 and 250 MMBtu/hr for packaged boilers.

[b] PC = Pulverized Coal; FBC = Fluidized Bed Combustion;

[c] CC = Combustion Control; SNCR = Selective Noncatalytic Reduction; SCR = Selective Catalytic Reduction.

[d] NA = Not Applicable

6.0 NO_x CONTROL TECHNIQUES FOR KRAFT PULP MILL SOURCES OTHER THAN FOSSIL FUEL–FIRED BOILERS

When compared to other industries' facilities, forest products industry facilities are somewhat unique in that they burn a significant quantity of wood and wood-derived fuels. Also, the combustion sources in pulp and paper mills, such as recovery furnaces and lime kilns, are unique to this industry. For example, from data in NCASI files, of the total thermal energy generated at 16 kraft mills to make bleached paperboard, energy derived from wood residue (bark and hogged fuel) combustion ranged from 0% to 32% , averaging about 15%, and energy derived from black liquor combustion ranged from 39% to 70%, averaging about 49%. Thus, on average, nearly 65% of the energy required at a kraft mill to make bleached paperboard is derived from biomass fuels. Consequently, the NO_x control issues faced by this industry are very different from those of others. This section discusses the potential for NO_x formation and NO_x emissions control in wood- and combination wood–fired boilers, kraft recovery furnaces, and kraft pulp mill lime kilns. Also included is a discussion on potential NO_x emissions resulting from the burning of foul condensate stripper off-gases (SOG).

6.1 NO_x Emissions and Control Techniques for Wood and Combination Wood–Fired Boilers

NO_x emissions resulting from wood residue combustion are typically low compared to emissions from coal or oil combustion. This is so because fuel NO_x is the dominant NO_x formation mechanism for most biomass combustion, and typical fuel wood N contents are far less than for coal or residual oil. In one study the mean N content of 14 hardwood tree species was found to be about 0.17%, while the mean for 16 softwood tree species was about 0.13% (NCASI 1992). By comparison, for typical anthracite coals, the N contents range from 0.2% to 1.8%, for typical bituminous coals, they range from 1.0% to 1.7%, and for typical sub-bituminous coals, they range from 0.7% to 1.5% (USEPA 1997). Typical N contents in nos. 4 to 6 fuel oils range from 0.3% to 2.2% (USEPA 1997). In addition, the heating values of wood residues are typically far less than those of coal and oil.

There are a few wood species that have N content as high as 0.5% to 1%. Examples of such species are red alder and some types of aspen. Typically, "juvenile" wood species will contain higher levels of N than the "older growth" species since the bark and foliage comprise a higher fraction of the overall tree and nitrogen tends to concentrate more in bark and foliage than in the stem of a tree. Finally, some boilers at the wood products manufacturing facilities are fired with board trim or sanderdust. Such boilers can have a high potential for NO_x emissions due to the relatively high N concentrations in urea formaldehyde resins contained in the product. Particleboard and medium density fiberboard residuals may have nitrogen contents up to 3%.

The impact on NO_x emissions from boilers firing wood residues in combination with other fossil fuels such as coal, oil, or natural gas is not well understood. In general, the contribution by thermal NO_x, formed only when fossil fuels are burned, to overall NO_x would be expected to be reduced. This is because a reduction is expected in the maximum combustion temperature when the lower heat value wood residue fuel is burned with the higher heat value fossil fuel. Recent test results showing reduction in NO_x emissions in a coal-wood residue combination boiler as the fraction of wood was increased were attributed to yet another factor, viz., the higher fuel volatility (expressed as the volatile to fixed carbon ratio) of wood residue compared to coal (Battista et al. 1998). The high volatility of the biofuels promotes early ignition in a fuel-rich regime of the flame, creating internal fuel staging and NO_x reduction (Battista et al. 1998).

Evidence of using combustion controls to reduce NO_x emissions from wood or combination wood-fired boilers is generally lacking. For stoker and fluidized bed combustor wood-fired units, USEPA's AP-42 document suggests overfire air ports may be used to lower NO_x emissions by staging the combustion process (USEPA 1996). However, details of boilers where such modifications have been made and evidence of NO_x reductions obtained thereby are not yet available. Preliminary indications of NO_x reductions achieved in coal and MSW stoker-fired boilers by the IGT reburning process METHANE DeNOX were alluded to earlier. Most wood residue-fired spreader stoker and fuel cell boilers inherently practice staged combustion by the use of overfire air (with the possible exception of some certain older Dutch oven boilers). Some NO_x reduction can be achieved by optimizing staged combustion at full loads, but this cannot be sustained when the boilers are operated at lower loads. Lower emissions of NO_x observed from some wood-fired spreader stoker units are likely a result of several factors, including the use of low excess air, optimum staged combustion, low nitrogen content fuels and steady load patterns. With load swings, high excess air is needed to minimize CO emissions, and thus additional NO_x reductions cannot be expected.

The use of SCR technology on combination wood-fired boilers would be considered technically infeasible based on the fact that post particulate removal flue gas temperatures are typically significantly lower than those desired for this application (450°F to 750°F). Reheating flue gases in these boilers to bring them within the desired temperature window would result in significant energy penalties. There is limited evidence in the literature that post-combustion NO_x emission control by the SNCR process can be applied to wood and combination wood-fired boilers. One vendor states the NO_xOUT SNCR process has been successfully applied for post combustion flue gas NO_x emissions control on several wood-fired electric-generating units ranging from 130 to 500 x 10^6 Btu/hr with target NO_x reductions typically around 50% (NALCO 1998). At least six pulp and paper industry combination boilers burning (a) oil/bark/biomass, (b) paper sludge, (c) paper, (d) fiber waste, (e) bark/gas, and (f) bark/coal/gas were reported to have installed the NO_xOUT process (NALCO 1998). An instance of post-combustion NO_x emission control using ammonia injection in a 100% wood-fired industrial boiler was first reported in 1987 (Makanski 1987). Ammonia injection was used to reduce NO_x emission from 35% to 70% for ammonia-to-NO_x molar ratios between 0.4 and 3.0. More recently, Abrams (1998) reported on problems experienced with an ammonia injection system installed on a newly constructed wood residue boiler for NO_x emissions control. While the manufacturer had guaranteed a NO_x emission limit of 0.042 lb/10^6 Btu, the boiler was unable to meet this guarantee unless operated at less than half load. Even then, reducing NO_x to near permitted limits consumed considerably more ammonia than anticipated, leading to the formation of a visible ammonium chloride salt plume.

6.2 NO_x Emissions and Control Techniques for Kraft Recovery Furnaces

As previously noted, just as for wood residue combustion, NO_x emissions from black liquor combustion in kraft recovery furnaces are also expected to result strictly from the "fuel NO_x" mechanism pathway. The highest temperatures measured in the recovery furnace, usually in the lower furnace region, range from about 1800°F to 2400°F. These are much lower than would be essential for appreciable NO_x formation by the thermal NO_x pathway (>2,800°F). Hence, due to the dominance of fuel NO_x formation pathways, factors that would minimize thermal NO_x formation by minimizing peak gas temperatures in the lower furnace, such as the firing of lower solids content liquors, effecting changes in combustion air temperature and pressure, changes in burner design and position, liquor temperature and density, perhaps have only a limited role in controlling NO_x formation.

A detailed investigation into the origins of kraft recovery furnace NO_x emissions and related parameters by NCASI concluded that black liquor N content was perhaps the most important factor affecting NO_x emissions from kraft recovery furnaces (NCASI 1992). Excess oxygen in the zone where the bulk of liquor combustion takes place was considered the second most important factor for NO_x

formation. While very little can be done to affect the liquor nitrogen content, staged air combustion, which is already integral to the operation of most recovery furnaces, is perhaps the best strategy for minimizing NO_x formation in kraft recovery furnaces. The precise distribution of combustion air between primary, secondary and, if relevant, tertiary or quaternary air levels is most likely quite furnace-specific. Forssen et al. (1998) studied the influence of various operating conditions on NO formation in the recovery furnace. Using both laboratory experiments and kinetic modeling studies, the authors conclude NO is formed from the oxidation of ammonia produced during liquor droplet devolatilization, and this oxidation is strongly dependent on the temperature and number of stages in which the air is mixed with the devolatilized gases. The authors implied that additional air feed levels in the upper furnace may aid in minimizing NO_x formation, although no full-scale test results were used to support this conclusion.

The abovementioned NCASI report on recovery furnace NO_x emissions (NCASI 1992) contained long-term continuous emissions monitoring data for NO_x emissions from several kraft recovery furnaces. These data showed the NO_x emissions fell within a fairly narrow range for each furnace, in spite of apparent, significant day-to-day changes in furnace operating behavior as suggested by the corresponding, widely fluctuating data for SO_2 and CO emissions. This lack of significant variability in a given recovery furnace's NO_x emissions would suggest most furnaces already use the concepts of staged combustion optimally, and the differences observed between one mill's furnace NO_x emissions and another's are mainly a result of the differences between their black liquor N contents. Another point to consider when effecting a change in operating conditions in a kraft recovery furnace is the resulting effect on emissions of compounds such as total reduced sulfur compounds, CO and other criteria pollutants (SO_2 and VOC) which often respond more significantly when reconfiguring the distribution of combustion air.

Relative to flue gas treatment as an NO_x control option, SNCR is not considered technologically feasible for kraft recovery furnaces (Kravett and Hanson 1994). This conclusion was based on the fact that a recovery furnace is a comple$_x$ chemical reaction system and any disruption of the delicate reaction chemistry could potentially damage the furnace, impact the quality of the product, or otherwise unacceptably affect the system. Also, like industrial boilers, kraft recovery furnaces operate at varying loads which makes it difficult to inject the SNCR reagent within the desired temperature window. Several technological limitations also come to bear when one considers the installation of an SCR system on a recovery furnace including (a) potential for plugging and fouling of the SCR catalyst, (b) potential for fouling of the ESP, (c) ammonia handling and ammonia slip emissions issues, (d) potential for increased particulate emissions, (e) creation of a new hazardous waste (spent catalyst), and (f) potential significant energy penalty (Kravett and Hansen 1994).

In a recent paper, Janka et al. (1998) compared field experiments for recovery furnace NO_x reduction using (a) air staging, (b) the SNCR method, and (c) an oxidation-reduction scrubber. Working primarily with large Scandinavian furnaces they conclude that air staging, which primarily involves adding a quaternary air level in a large furnace, could potentially result in up to a 30% NO_x reduction. The SNCR method, while applicable to achieve up to a 60% NO_x reduction, would cost several million dollars for storing, feeding, and control systems for the SNCR agent. Insufficient details on the O-R scrubber make the efficacy of this application difficult to judge at the present time. In summary, the use of quaternary air may be useful in achieving marginal NO_x reductions in certain large or newly designed furnaces, while the reservations for use of SNCR mentioned above appear to be still valid.

In a summary assessment of control technologies for reducing nitrogen oxide emissions from non-utility point sources and major area sources, USEPA stated "NO_x emissions from recovery boilers do not generally result from thermal oxidation of nitrogen in the air. Oxidation of fuel nitrogen, which appears to be the dominant mechanism for recovery boiler NO_x formation, can be sensitive to furnace temperature, however. Changes in the process, such as low excess air and air staging, may reduce NO_x emissions in some cases. SNCR may be applicable as a post-process reduction technique. It should be noted, though, that most recovery furnaces already operate with relatively low excess air with little room for significant improvement. While some gains can be achieved in the newer (larger) furnaces, the use of these techniques may also result in increases in SO_2 and CO emissions and can foul and plug the convection passes, increase acid deposition, and result in production losses" (USEPA 1998).

6.3 NO_x Emissions and Control Techniques for Kraft Pulp Mill Lime Kilns

Lovblad et al. (1993) reviewed NO_x emissions from three Swedish lime kilns burning different fuels including tall oil, fuel oil, methanol, turpentine, bark and wood powder, bark gasifier pyrolysis gases, and non-condensible gases from pulping and condensate stripping areas of a pulp mill. Correlations between the fuel type and NO_x emissions generally reflected the N contents of the fuels. In one kiln, the NO_x emissions correlated well with the combustion temperature. Such a relationship was also observed in the case of one kiln during a 1980 NCASI study (NCASI 1980). Some authors have reported an increase in observed NO_x emissions from kilns when burning non-condensible gases (Lovblad et al., 1993; Kiiskila 1990). However, the causes for this increase are not clear. Burning NCGs may require an increase in the amount of excess air used for combustion or may require certain combustion flame adjustments to be made to accommodate the NCG burning so as to continue to meet the strict TRS emission limits generally imposed on lime kilns. Besides potential nitrogenous substances present in the NCGs that may oxidize to NO_x, these other factors may also influence NO_x emissions.

Fossil fuels burned in a kraft pulp mill lime kiln typically comprise only about 10% of the total energy expended to make the pulp or paper product. Fossil fuels such as natural gas or residual fuel oil are typically burned in the kiln to generate the bulk of the energy required for calcination of the lime mud. Lime kilns are designed to recover "reburned" lime or CaO by calcining the $CaCO_3$-containing lime mud with hot combustion gases resulting from fossil fuel combustion. No heat recovery occurs in the kiln, and kiln gases typically exit at about 450°F prior to being treated by a wet scrubber or ESP for particulate emission control. As such, the design of the lime kiln precludes the use of post-combustion NO_x reduction techniques such as SNCR and SCR. Only combustion control techniques valid for other fossil fuel–fired combustion units outlined earlier would be applicable to lime kiln NO_x emissions control. However, no systematic study of NO_x formation and NO_x emission reduction in lime kilns has been conducted in the U.S., possibly due to the need to operate the kiln within a fairly narrow temperature range to achieve proper lime moisture content. In a Best Available Control Technology (BACT) analysis conducted on a new lime kiln in 1997, the use of low NO_x burners was determined to be technically infeasible due to complexities resulting in poor efficiency, increased energy usage, and decreased calcining capacity (NCASI 1998).

More importantly, though, it is not clear why NO_x emissions measured from various lime kilns in the United States vary as much as they do. Table 1 showed that uncontrolled NO_x emission factors for natural gas and residual oil combustion in industrial boilers ranged from 0.17 to 0.25 lb/10^6 Btu and from 0.28 to 0.45 lb/10^6 Btu, respectively. In a 1980 NCASI study NO_x emissions measured from six lime kilns, four burning residual oil and two burning natural gas, ranged from as low as 0.07 lb/10^6 Btu to as high as 1.12 lb/10^6 Btu, averaging about 0.42 lb/10^6 Btu (NCASI 1980). Including these six kilns NCASI reported NO_x emissions from 14 kilns burning either natural gas or residual oil ranged from as low as 0.01 to as high as 1.12 lb/10^6 Btu, averaging about 0.27 lb/10^6 Btu (NCASI 1993). Although never demonstrated, low NO_x emissions from certain lime kilns could be a result of some of the NO_x formed in the flame zone being captured downstream by the fine lime dust or in the wet alkaline scrubber, or in the case of kilns which also treat stripper off-gases (SOGs), the ammonia present in such SOGs could serve as a reducing agent converting some of the NO_x present to N_2. Alternately, high lime kiln NO_x emissions may result either from the oxidation of nitrogenous substances in the treated SOGs or from the different ways in which excess combustion air is manipulated in the flame zone of a lime kiln in order to maintain adequate control of the regulated total reduced sulfur (TRS) compound emissions. In conclusion, while traditional NO_x control techniques such as use of low NO_x burners could no doubt be applied to lime kilns, the wide range in existing lime kiln NO_x emission data suggest clearly that NO_x control strategies for each kiln have to be evaluated on a case-by-case basis. Minimizing the use of excess air, while staying within regulated limits for TRS compounds, may be the most viable NO_x control technique applicable to lime kilns.

6.4 NO_x Emissions from Kraft Pulp Mill Incineration of NCGs and SOGs

In a kraft pulp mill, SOGs result from the stripping of foul condensates. This practice is expected to become increasingly common, especially as mills begin to respond to the recently promulgated “Cluster Rule.” Kraft foul condensates can contain significant levels of ammonia in addition to methanol and other VOCs which will be stripped off when the condensates are subject to steam stripping. If the SOGs are not subjected to methanol treatment (i.e., methanol removal) prior to incineration, or if the separated methanol is burned along with the SOGs in a boiler, lime kiln, or thermal oxidizer, significant NO_x emissions can potentially result from oxidation of the NH_3 present in the SOGs. These emissions would be in addition to the NO_x emissions expected from burning of fossil fuels and/or the SOG VOC content. In tracking the fate of nitrogen in a kraft mill chemical recovery process, Kymalainen et al. (1998) conclude “the stripping of foul condensates to be the main exit point for ammonia in the recovery process, the amount of this ammonia nitrogen being very significant and corresponding almost to a typical NO_x emission of a recovery furnace.”

Limited measurement data in NCASI files on foul condensate ammonia concentrations appear to support this conclusion. Ammonia concentrations in foul and steam-stripped condensates from two kraft pulp mills ranged from 140 to 170 ppm and from 1.7 to 2.2 ppm, respectively. Thus, over 98% of the NH_3 present in the foul condensates was stripped, presumably ending up in the SOGs. Each mill had a pulping capacity of about 1500 tpd, and the amount of NH_3 stripped ranged from about 28 to 50 lb/hr. If the SOGs contained all the stripped NH_3 and if the NH_3 in the SOGs were assumed to completely oxidize to NO_x during treatment, NO_x emissions ranging from 1.2 to 2.1 lb/ton pulp would have resulted. This would be comparable to NO_x emissions from typical kraft recovery furnaces. In an NCASI study, NO_x emissions from 11 kraft recovery furnaces ranged from 1.8 to 3.9 lb/ton pulp, averaging about 2.3 lb/ton (NCASI 1992).

However, it is not clear as to what extent the ammonia to NO_x conversion occurs in various incineration devices and what baseline level of NO_x can be expected when burning concentrated pulp mill NCGs and the combustible constituents in SOGs (such as methanol). As discussed earlier in section 4.2.1 (a), when injected in gases within a temperature window of about 1600°F to 2200°F, ammonia reduces NO_x to N_2. Below about 1600°F, ammonia most likely remains unreacted, leading to the so-called “ammonia slip.” Above about 2000°F to 2200°F, the injected ammonia mostly oxidizes to NO_x. Thus, in cases where SOGs are treated in boilers or lime kilns, if temperatures in the zone of SOG introduction exceed 2200°F, the ammonia present in the SOGs will likely completely oxidize to NO_x. If, however, the SOGs are introduced in zones where temperatures are below about 2000°F, the ammonia is likely to either remain unreacted or even participate in the reduction of NO_x already present in the combustion gases.

Limited data on NO_x emissions from burning of SOGs in dedicated thermal oxidizers currently available to NCASI suggest that while the presence of SOGs could lead to increased NO_x emissions, this increase is much less than that corresponding to complete conversion of ammonia to NO_x. Stack test data for NO_x emissions from 15 TRS thermal oxidizers were obtained by NCASI during a 1995 survey, and these averaged about 0.3 lb/ton pulp (NCASI 1997). However, it was unclear how many of these oxidizers were burning SOGs along with other NCGs. Bloom (1998) reported NO_x emissions from three oxidizers burning SOGs ranged from 176 to 225 ppm. However, other details such as gas flow rate, pulping rate, etc. were not provided, making it difficult to convert these emissions to a lb per ton pulp basis. Recent test data corresponding to a southeastern U.S. kraft pulp mill thermal oxidizer which treats pulp mill NCGs including SOGs showed NO_x emissions to be about 0.32 lb/ton pulp. After modifications in the manner in which the SOGs were introduced into the oxidizer were made, additional tests were carried out, and these changes resulted in NO_x emissions to be further reduced to below 0.2 lb/ton pulp. NO_x emission test data from another southeastern U.S. kraft pulp mill thermal oxidizer burning concentrated NCGs and SOGs showed a strong relationship between NO_x emissions and the excess air used in the oxidizer (as measured by the stack O_2 concentration). NO_x emissions were as low as 0.01 lb/ton pulp at 1.0% O_2 to as high as 0.79 lb/ton pulp at 13.2% O_2 in the stack. Most thermal oxidizers operate at temperatures below about 1600°F, making it quite likely that much of the NH_3 in the SOGs treated in these oxidizers will remain unreacted and no net increase in NO_x emissions will result from the ammonia content itself. Also, since most thermal oxidizers burning SOGs are equipped with a wet scrubber for SO_2 removal, the unreacted ammonia is expected to be removed in such a scrubber. In conclusion, NO_x emission control strategies for units burning SOGs in a kraft mill should take the above anomalies into consideration.

7.0 SUMMARY

This report reviewed the current state of understanding of how NO_x is formed during combustion of fossil and biomass fuels. For fossil fuel–fired boilers, brief descriptions of techniques for reducing NO_x formation by installing various combustion modifications, as well as for reducing NO_x emissions by installing SNCR and SCR flue gas treatment systems, were provided. The limitations of applying NO_x control technologies, currently proven mainly for utility fossil fuel–fired boilers, to fossil fuel–fired and biomass fuel–fired industrial boilers were outlined. The uniqueness of NO_x emissions from combustion units typically present in a kraft pulp and paper mill, including wood and combination wood–fired boilers, kraft recovery furnaces and kraft pulp mill lime kilns and the potential for their control, were discussed. The complexities surrounding the burning of stripper off-gases and concentrated NCGs in boilers, lime kilns, and dedicated thermal oxidizers were also highlighted.

USEPA's recommendations of proven NO_x control technologies applicable to fossil fuel–fired industrial boilers as laid out in the technical support document for its recently promulgated revisions to the NSPS Subpart Db NO_x emission limits and the results of a 1989 Wisconsin DNR study that evaluated several NO_x emission reduction or removal technologies for all industrial boilers in the state of Wisconsin were presented. Control cost estimates derived in the Subpart Db supporting document were also presented for model industrial boilers. These estimates provided costs for combustion control (CC), CC with SNCR, and CC with SCR for various coal-fired, gas-fired, and oil-fired industrial boilers.

Based upon available information the following key observations were made:

- The use of low NO_x burners with secondary air appears to be a viable NO_x control technology for all fossil fuel-fired industrial boilers. However, flame impingement is a valid concern in small, packaged boilers.

- Flue gas recirculation may be applicable to natural gas- and oil-fired industrial boilers. However, windbox capacities, tube wall erosion and damage from changes in water circulation patterns should be considered.

- SNCR can theoretically be applied to industrial boilers firing any combination of coal, oil, natural gas, or biomass. However, several limitations unique to industrial boilers such as swinging loads, availability of the correct temperature window for NH_3 or urea injection, inadequate mixing, and excessive ammonia slip need to be considered.

- Swinging steam loads, problems with ammonia slip, catalyst deterioration and pluggage, significant costs and generally a lack of demonstrated experience with industrial boilers in the United States would likely rule out application of SCR technology to most industrial boilers.

- Swinging steam loads also limit the amount of NO_x reduction that can be achieved in stoker-fired industrial boilers through limiting excess air.

- Optimizing combustion conditions by manipulating the combustion air is likely the most effective NO_x control technique for kraft recovery furnaces, although the improvements are expected to be marginal. Most recovery furnaces are already operated with optimum staged combustion.

- While combustion modifications offer the best NO_x control strategy in lime kilns, NO_x formation and reduction mechanisms in kilns are not well understood. As such, they need to be investigated on a case-by-case basis.

- The potential for NO_x emissions from burning untreated stripper off-gases in certain kraft mill combustion systems needs to be considered in future mill NO_x emissions and inventory exercises.

Overall, the importance of recognizing that the nitrogen content of all biomass fuels, including wood residues, spent pulping liquors, and waste treatment plant residuals, is the most important contributing factor towards NO_x formation and emissions cannot be understated. NO_x control strategies for units burning biofuels should revolve around control of fuel NO_x and not thermal NO_x.

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Estimated Average Cost ($/ton) of WESP Addition on No. 2 Power Boiler - PM Control[L]

CAPITAL COSTS		**Costs ($)**
Direct Costs		
Purchased Equipment Cost[a]	**$**	**4,609,696**
Budgetary Qualifier (+/-25%)		1,152,424
		5,762,120
Direct installation costs		
Foundation and supports		
Handling and erection		
Electrical		
Piping		
Insulation		
Painting		
Direct installation Costs		2,881,060
Total Direct Capital Cost = Equip Cost + 1.5*Equip Cost[b]	$	8,643,180
Indirect Capital Costs	=1.0 x Total Direct Cost	
Engineering		
Construction and field expenses		
Contrator fees		
Start-up		
Performance test		
Contingencies		
Structural Modification (4%)		
Total Indirect Capital Costs[b]	$	8,643,180
TOTAL CAPITAL INVESTMENT (TCI = DC+IC)	**$**	**17,286,360**
OPERATING COSTS		
Direct Operating Costs		
Operating Labor[c]		9,022
Operating Labor Supervision[d]		1,353
Maintenance Labor[e]		9,922
Maintenance Materials[f]		9,922
Utilities - Electricity[g]		74,592
Utilities - Water		
Waste Treatment & Disposal		
Total Direct Operating Costs	$	104,811
Indirect Operating Costs		
Overhead[h]		18,131
Property Tax[i]		172,864
Insurance[i]		172,864
Administration[j]		345,727
Capital Recovery (5% interest, 10 year life)[k]		2,238,663
Total Indirect Operating	$	2,948,248
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)	**$**	**3,053,059**
Total Annualized Costs		3,053,059
Total Uncontrolled PM Emissions (tpy)		252
Removal Effciency[m]		0.4
Pollutant Removed(tpy)		101
Cost/Ton Pollutant Removed	**$**	**30,348**

[a] Based on six-tenths factor rule for cost estimation from Peters, Max S. and Timmerhaus, Klaus D., Plant Design and Economics for Chemical Engineers, Fourth Edition, McGraw-Hill, Inc., 1991, p. 169.

[b] Factored estimate based on recent capital project installations

[c] Operating labor = 0.75 hours/day @ $34.37/hr rate for 350 days/year

[d] Supervisor pay = 15% of Operator pay

[e] Maintenance = 240 hours @ $41.34/hr

[f] Maintenance Materials = 100% of Maintenance Labor

[g] Electrical usage assumption (222kW) associated with running auxiliary equipment; from Lundberg proposal for No. 1 PB estimate for OFA/FGR combo

[h] Overhead = 60% of Labor & Material

[i] =1% TCI (Total Capital Investment)

[j] =2% TCI (Total Capital Investment)

k =factor of 0.129504575 for 5% interest on 10 year life

L = All costs based on proposal for No. 1 Power Boiler. No adjustments made for likely larger size requirements on No. 2 Power Boiler. Therefore, cost/ton likely to be even greater than $30,348.

m=Current WESP proposal desing outlet is 40% of Boiler MACT limit. PM already at Boiler MACT limit on No. 2 PB, so reduction estimate is only 40%.

Entergy

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AR-07-016

March 1, 2007

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Reference: **White Bluff and Lake Catherine BART Reports**
Supplemental Information Submittal per February 15, 2007 Conference Call

Ms. Pettyjohn:

Provided below are responses to questions the Agency raised during our discussions regarding BART compliance at our White Bluff and Lake Catherine Unit 4 plants. Our response follows the questions which appear in bold text.

Questions/Issues regarding Lake Catherine Unit 4 and responses are as follows:

1. **ADEQ requested the modeling files.**

Modeling files were e-mailed by Bob Paine with ENSR on February 22, 2007. ADEQ confirmed receipt of these files on February 26, 2007.

2. **ADEQ requested the control cost in $/ton rather than $/deciview.**

Entergy's BART submittal provided costs using both units. ADEQ will review the report and advise if additional information is needed.

3. **ADEQ requested the citation regarding why LC4 was exempt from installing post combustion controls.**

The excerpt from page 367 of the final BART guidelines is below

> *For oil-fired and gas-fired EGUs larger than 200MW, we believe that installation of current combustion control technology to control NOX is generally highly cost-effective and should be considered in your determination of BART for these sources. Many such units can make significant reductions in NOX emissions which are highly cost-effective through the application of current combustion control technology.21*

> *21See Technical Support Document for BART NOX Limits for Electric Generating Units and Technical Support Document for BART NOX Limits for Electric Generating Units Excel Spreadsheet, Memorandum to Docket OAR 2002-0076, April 15, 2005.*

This guidance states combustion controls for gas and oil are highly cost effective, directly above this statement in the guidance EPA states that SCR is not cost effective for an existing coal facility unless it is a cyclone unit so it would make sense that EPAs guidance that combustion controls for presumptive coal controls also applies to gas and oil units. See excerpt below, bold emphasis added.

> *5. Nitrogen oxide limits for utility boilers*
> *You should establish specific numerical limits for NOX control for each BART determination. For power plants with a generating capacity in excess of 750 MW currently using selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) for part of the year, you should presume that use of those same controls year-round is BART. For other sources currently using SCR or SNCR to reduce NOX emissions during part of the year, you should carefully consider requiring the use of these controls year-round as the additional costs of operating the equipment throughout the year would be relatively modest.*
> ***For coal-fired EGUs greater than 200 MW located at greater than 750 MW power plants and operating without post-combustion controls (i.e. SCR or SNCR), we have provided presumptive NOX limits, differentiated by boiler design and type of coal burned.*** *You may determine that an alternative control level is appropriate based on a careful consideration of the statutory factors.* ***For coal-fired EGUs greater than 200 MW located at power plants 750 MW or less in size and operating without post-combustion controls, you should likewise presume that these same levels are cost-effective.*** *You should require such utility boilers to meet the following NOX emission limits, unless you determine that an alternative control level is justified based on consideration of the statutory factors. The following NOX emission rates were determined based on a number of assumptions, including that the EGU boiler has enough volume to allow for installation and effective operation of separated overfire air ports. For boilers where these assumptions are incorrect, these emission limits may not be cost-effective.* ***Most EGUs can meet these presumptive NOx limits through the use of current combustion control technology, i.e. the careful control of combustion air and low-NOx burners. For units that cannot meet these limits using such technologies, you should consider whether advanced combustion control technologies such as rotating opposed fire air should be used to meet these limits.*** *For units that cannot meet these limits using such technologies, you should consider whether advanced combustion control technologies such as rotating opposed fire air should be used to meet these limits.*

Note: Presumptive SCR is only mentioned for cyclone units

> *Because of the relatively high NOX emission rates of cyclone units, SCR is more cost-effective than the use of current combustion control technology for these units. The use of SCRs at cyclone units burning bituminous coal, sub-bituminous coal, and lignite should enable the units to cost-effectively meet NOX rates of 0.10 lbs/ mmbtu. As a result, we are establishing a presumptive NOX limit of 0.10 lbs/mmbtu based on the use of SCR for coal-fired cyclone units greater than 200 MW located at 750 MW power plants. As with the other presumptive limits established in this guideline, you may determine that an alternative level of control is appropriate based on your consideration of the relevant statutory factors. For other cyclone units, you should review the use of SCR and consider whether these post-combustion controls should be required as BART.*

Entergy's BART Report also provided control pricing up to $10,000/ton removed in our determination report. At $10,000/ton we did not get to LNB. Therefore, SCR would definitely not be cost effective with the capacity factor projected for Lake Catherine Unit 4.

Table ES-2 Tabulation of Visibility Improvement and Annual Costs for BART NOx Control Option for Oil Firing

Control Scenario Options	Description	Annualized Cost ($/year)	Incremental Cost from Previous Control Scenario ($/Year)	Delta deciviews from natural conditions (98th percentile day)	Incremental Cost Effectiveness ($/deciview Relative to the Previous Control Scenario)	Annual tons NO_x removed	Incremental Cost Effectiveness ($/ton Relative to the Previous Control Scenario)
Baseline	Base case	--	--	3.44	--	--	--
1	Boiler tuning	$16,000	$16,000	3.31	$130,085	220.0	$73
2	Tuning, burner mods	$433,934	$417,933	3.14	$2,347,939	462.9	$1,720
3	Tuning, burner mods, BOOS	$583,386	$149,452	3.03	$1,450,989	523.5	$2,469
4	Tune, burner mods, BOOS, FFGR	$1,357,123	$773,737	2.90	$5,906,393	600.1	$10,101

4. ADEQ asked why the Lake Catherine Title V Permit does not state a limit of 1% sulfur fuel oil.

Entergy stated during discussions that limits in the permit are based on 1% oil and this will likely be included in the permit as a limit when BART is incorporated into the permit.

5. ADEQ requested a Compliance plan and schedule for implementation starting from the Arkansas SIP approval date (unknown at this time ~ Dec 07).

Compliance plan:
As stated in Section 5.0 of the BART Analysis for Lake Catherine Plant, projected control technology to meet BART limits will be a combination of tuning, BOOS and IFGR.
Schedule:
Entergy will implement a construction schedule that ensures that Lake Catherine Unit 4 will comply with the limits submitted in the Lake Catherine BART determination report within five years of EPA approval of the Arkansas Regional Haze SIP.

6. ADEQ requested submission of requested limit, averaging time period, and associated language.

The following excerpt below from Final BART Guidance, page 370 is provided below:

> *for EGUS, specify an averaging time of a 30-day rolling average, and contain a definition of "boiler operating day" that is consistent with the definition in the proposed revisions to the NSPS for utility boilers in 40 CFR Part 60, subpart Da. 22 You should consider a boiler operating day to be any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit. This would allow 30-day rolling average emission rates to be calculated consistently across sources.*

The BART determination conducted by Entergy concluded the following limits are applicable to comply with BART.

SO2 limit – Limit sulfur content of the oil to 1% sulfur
PM limit - sulfur content of the oil to 1% sulfur
NOx limit – Limit will be based on a 30 day rolling average
Gas firing – 0.15 lb/mmBtu
Oil firing - 0.28 lb/mmBtu
Dual fuel firing – When combusting oil and gas the 30 day rolling average limit will be prorated based on fuel consumed.
Dual fuel 30 day rolling average limit (lb/mmBtu) =
(0.15 * 30 day mmBtu gas) + (0.28 * 30 day mmBtu Oil) / (30 day mmBtu gas +30 day mmBtu Oil)

Questions/Issues regarding White Bluff Plant and responses are as follows:

1. ADEQ requested the modeling files.

Modeling files were e-mailed by Bob Paine with ENSR on February 22, 2007. ADEQ confirmed receipt of these files on February 26,2007.

2. ADEQ requested a Compliance plan and schedule for implementation starting from the Arkansas SIP approval date (unknown at this time ~ Dec 07).

Compliance plan:
As stated in the BART Analysis for the White Bluff Steam Electric Station, projected control technology to meet BART limits will be scrubbing for SO2 and boiler tuning, OFA, and LNB for NOx.

Schedule:
Entergy will implement a construction schedule that ensures the White Bluff Units 1 & 2 will be able to comply with the limits submitted in White Bluff BART determination report within five years EPA approval of the Arkansas Regional Haze SIP.

3. **An issue was raised regarding the Aux-boiler being considered as exempt from BART. The suggestion was made to take a ~1000 hours of operation limit. Entergy stated that there was guidance from EPA to support that BART does not apply to this source. Start-up boilers are exempt and there seems to be confusion on the aux-boiler because it is not called "Start-up boiler". The only use for the aux-boiler is start-up of Units 1 and/or 2 when both units are down and there is no generator associated with the aux-boiler. ADEQ requested a copy of the EPA guidance for their review.**

Entergy is providing the attached EPA Guidance Document (See answer to question 19).
Please note, however, that if the auxiliary boilers are only used during startup, then since we do not model startup conditions, those boilers would not contribute any emissions to the modeled visibility impact from the source; therefore those particular boilers may be exempted.

4. **ADEQ had questions about our considering the ESPs as BART for PM.**

After discussion ADEQ agreed with Entergy's determination that existing ESPs are BART for PM.

5. **ADEQ requested we submit our requested limit, averaging time period, and associated language.**

White Bluff Units 1&2 will comply with Presumptive Limits as outlined EPA's Final BART guidance document beginning on page 351.

S02 - 0.15 lb/mmBtu or 95 % removal of SO2 on a 30 day rolling average
PM – Operation of Electrostatic Precipitator according the Compliance Assurance Monitoring Plan
NOx –Limit will be based on a 30 day rolling average for Tangential fired units from Table 1 on page 108 of Final BART guidelines.
Subbituminous fuel - 0.15 lb/mmBtu
Bituminous fuel - 0.28 lb/mmBtu
Dual fuel firing – When combusting blended fuels the 30 day rolling average lb/mmBtu limit will be prorated based on fuel consumed

We appreciate the opportunity to discuss these issues with you and ADEQ staff members. Should you have questions or require additional information, please call Tracy Johnson at 501-377-4033.

Sincerely,

Tracy Johnson

For: Mark C. Bowles
Manager
Arkansas Environmental Support

Prepared for:
Entergy Services, Inc.

BART Analysis for Lake Catherine Plant – Unit 4

ENSR Corporation
December 2006
Document No.: 10785-006-111

Prepared for:
Entergy Services, Inc.

BART Analysis for Lake Catherine Plant – Unit 4

Robert J. Paine

Prepared By: Robert Paine

Olga Kostrova

Reviewed By: Olga Kostrova

ENSR Corporation
December 2006
Document No.: 10785-006-111

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Executive Summary

Unit 4 of Entergy's Lake Catherine plant in Jones Mills, Arkansas has been identified as a BART-eligible source by the Arkansas Department of Environmental Quality (ADEQ). CALPUFF modeling for BART exemption results indicate that this BART-eligible unit could have a potential visibility impact above the 0.5 deciview exemption threshold, meaning that a site-specific BART analysis is required. This report summarizes the BART analysis performed for Unit 4.

Unit 4 is a Combustion Engineering tilting tangential fired boiler with a maximum output of 552 MW. Unit 4 is permitted to burn natural gas and #6 oil. This unit, which came on-line in 1970, has no near-term limitations on its useful life.

Class I areas within 300 km of the facility include Caney Creek, Upper Buffalo, and Hercules Glades Wilderness Areas. CENRAP meteorological database was used for CALPUFF modeling that includes the Lake Catherine plant and the three Class I areas mentioned above.

Most of the visibility-causing emissions from Unit 4 are due to NO_x, since SO_2 and PM_{10} emissions from natural gas-fired boilers are very low and when combusting fuel oil the sulfur content of the fuel oil is limited to 1% sulfur by the Title V permit. Therefore, the BART analysis addresses NO_x controls and low sulfur oil fuel SO_2 controls. The guidance presented in EPA's BART rule Appendix Y to Part 51 advises that BART for gas/oil fired units is combustion control technology, not post-combustion controls such as SCR. Accordingly, control options including various forms of current combustion control technology are considered in the BART determination analysis described in this report. The Lake Catherine plant has a capacity less than 750 MW, so it is not subject to presumptive BART controls.

The NO_x BART options considered the following controls when combusting natural gas, which are cumulative with each successive option: boiler tuning, induced flue gas recirculation (IFGR), burners out of service (BOOS), overfire air (OFA), and low-NO_x burners (LNB). The NO_x BART options considered the following controls when combusting fuel oil, which are cumulative with each successive option: boiler tuning, burner modifications, burners-out-of-service (BOOS), and Forced Flue Gas Recirculation (FFGR). Entergy developed costs per ton removed for each of these control options. Including with the base case, this resulted in six scenarios to be modeled for natural gas combustion and five scenarios to be modeled for fuel oil combustion. For each scenario, the daily maximum SO_2 and PM_{10} emissions modeled for the base case were held constant. For oil firing, additional control options for SO_2 and PM_{10} emission decreases were evaluated associated with the use of lower sulfur oil. The costs for these options were associated with the increased cost of the fuel purchases as well as the lower heating value for the lower sulfur fuels.

The results of the CALPUFF visibility improvement modeling while combusting natural gas, along with the cost control information, are provided in Table ES-1 for the worst-case year and Class I area for an assumed 10% capacity factor for Unit 4. These results are also provided in a plot (Figure ES-1) showing the visibility improvement vs. the control costs. One key feature of the plot is that the regional haze reduction relative to natural background is predicted to be about 0.6 delta deciviews from the use of boiler tuning, BOOS, and IFGR for an annualized cost of about $400,000. The next control option (OFA) results in a much higher the cost per deciview improvement, with only 0.2 delta deciview improvement. Beyond that scenario, the addition of overfire air increases the cost significantly as measured by the cost per deciview of visibility improvement. The addition of low-NO_x burners increases the removal cost significantly as well. It is apparent that due to significant cost increases, reduced benefits, and complexities in the retrofits beyond BOOS and IFGR as described in this report, BART is determined to be a combination of tuning, BOOS and IFGR (NO_x control Option 3).

The results of the CALPUFF visibility improvement modeling while combusting fuel oil, along with the cost control information, are provided in Table ES-2 for the worst-case year and Class I area. These results are also provided in a plot (Figure ES-2) showing the visibility improvement vs. the control costs for a 10% unit capacity factor. Based on the modeling results of all NO_x control options with 1% sulfur oil, BART is determined to be a combination of boiler tuning with burner modifications and BOOS (Option 3). Option 3 for NO_x control was then modeled with the lower sulfur oil options. The CALPUFF visibility improvement modeling results are provided in Table ES-3. Figure ES-3 shows the visibility improvement vs. the control costs of all NOx control options with 1% sulfur oil (blue line) and the selected BART control Option 3 with 0.5% and 0.2% sulfur oil (red line). One key feature of these plots is that the incremental cost per deciview improvement increases markedly for lower sulfur oil use due to the additional fuel cost. It is apparent that due to significant cost increases, reduced benefits, and complexities in the retrofits beyond the tuning, boiler modifications, and BOOS for NO_x and for lower sulfur oil for SO_2 as described in this report, BART is determined to be a combination of 1% sulfur oil, boiler tuning, modifications, and BOOS.

Table ES-1 Tabulation of Visibility Improvement and Annual Costs for BART Option for Natural Gas Firing

Control Scenario Options	Description	Annualized Cost ($/year)	Incremental Cost from Previous Control Scenario ($/Year)	Delta deciviews from natural conditions (98th percentile day)	Incremental Cost Effectiveness ($/deciview Relative to the Previous Control Scenario)	Annual tons NO_x removed	Incremental Cost Effectiveness ($/ton Relative to the Previous Control Scenario)
Baseline	Base case	--	--	1.56	--	--	--
1	Boiler tuning	$17,016	$17,016	1.30	$64,947	215.2	$79
2	Tune, BOOS	$122,956	$105,940	0.99	$346,208	452.8	$446
3	Tune, BOOS,IFGR	$397,923	$274,967	0.56	$630,659	748.9	$929
4	Tune, BOOS,IFGR, OFA	$1,537,731	$1,139,807	0.34	$5,228,474	904.3	$7,335
5	Tune, BOOS,IFGR, OFA, LNB	$3,581,027	$2,043,297	0.27	$30,048,478	953.2	$41,739

Figure ES-1 Plot of Visibility Improvement vs. Annualized Control Cost for BART Options for Natural Gas Firing

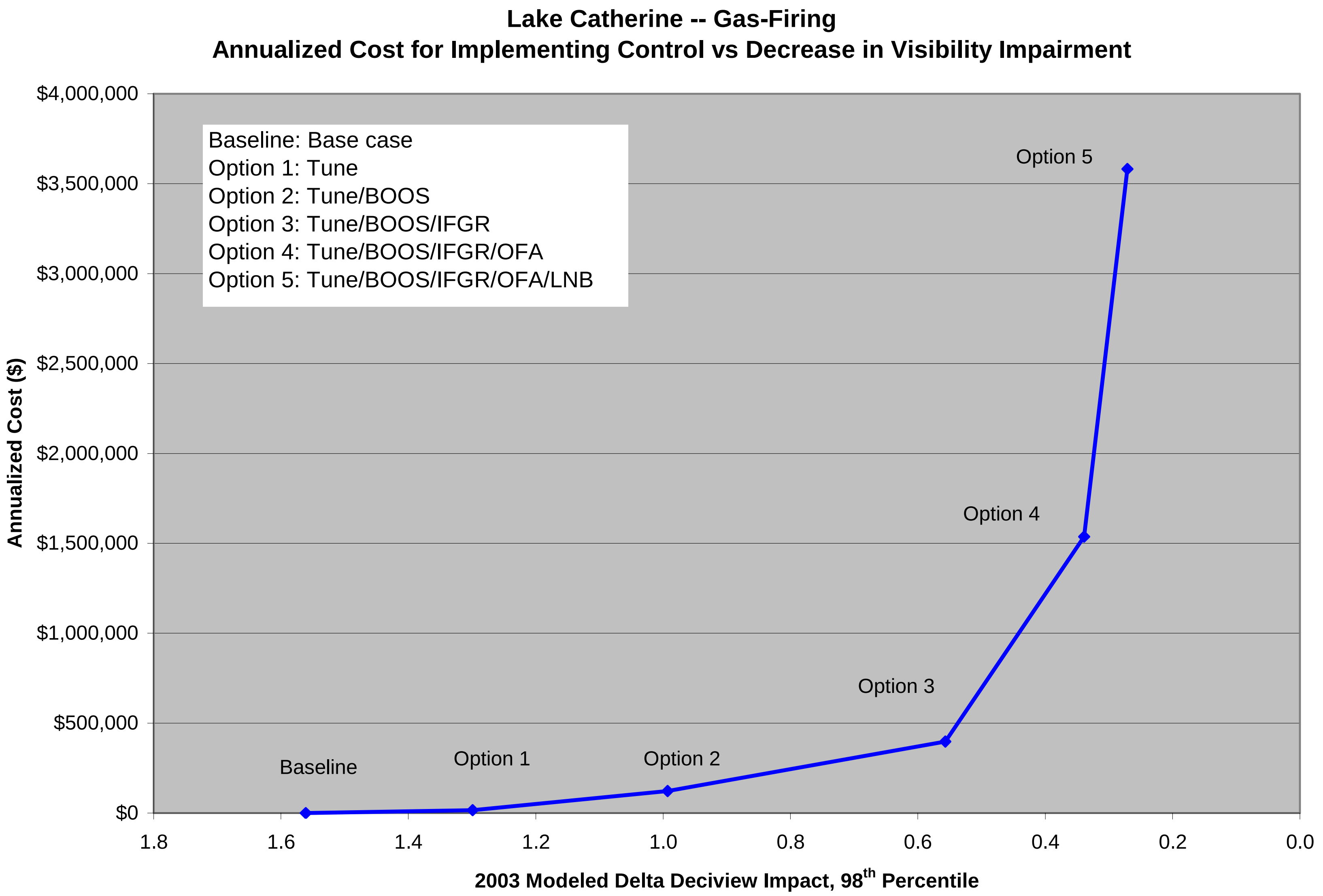


Table ES-2 Tabulation of Visibility Improvement and Annual Costs for BART NOx Control Option for Oil Firing

Control Scenario Options	Description	Annualized Cost ($/year)	Incremental Cost from Previous Control Scenario ($/Year)	Delta deciviews from natural conditions (98th percentile day)	Incremental Cost Effectiveness ($/deciview Relative to the Previous Control Scenario)	Annual tons NO_x removed	Incremental Cost Effectiveness ($/ton Relative to the Previous Control Scenario)
Baseline	Base case	--	--	3.44	--	--	--
1	Boiler tuning	$16,000	$16,000	3.31	$130,085	220.0	$73
2	Tuning, burner mods	$433,934	$417,933	3.14	$2,347,939	462.9	$1,720
3	Tuning, burner mods, BOOS	$583,386	$149,452	3.03	$1,450,989	523.5	$2,469
4	Tune, burner mods, BOOS, FFGR	$1,357,123	$773,737	2.90	$5,906,393	600.1	$10,101

Figure ES-2 Plot of Visibility Improvement vs. Annualized Control Cost for BART Options for Fuel Oil Firing

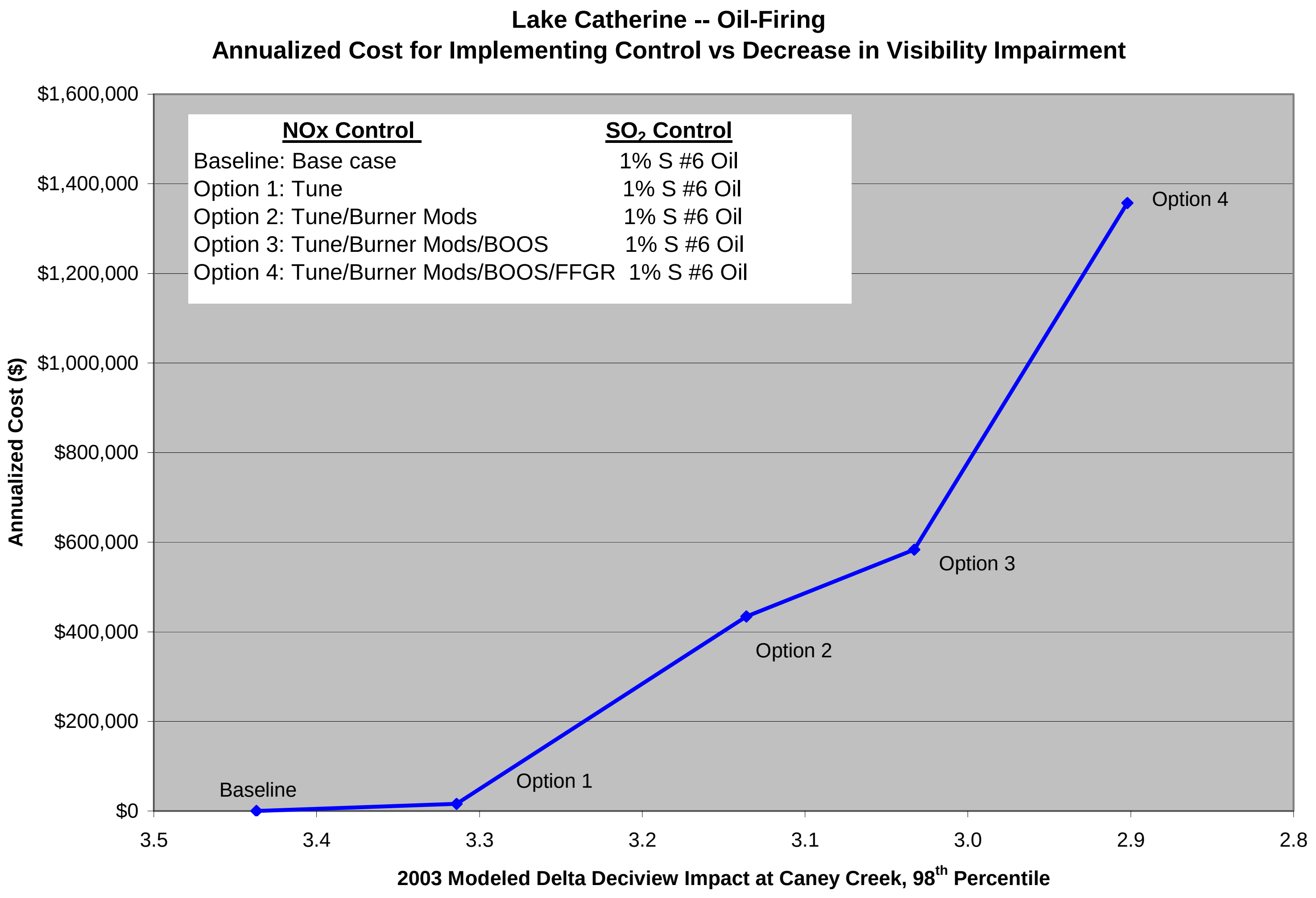


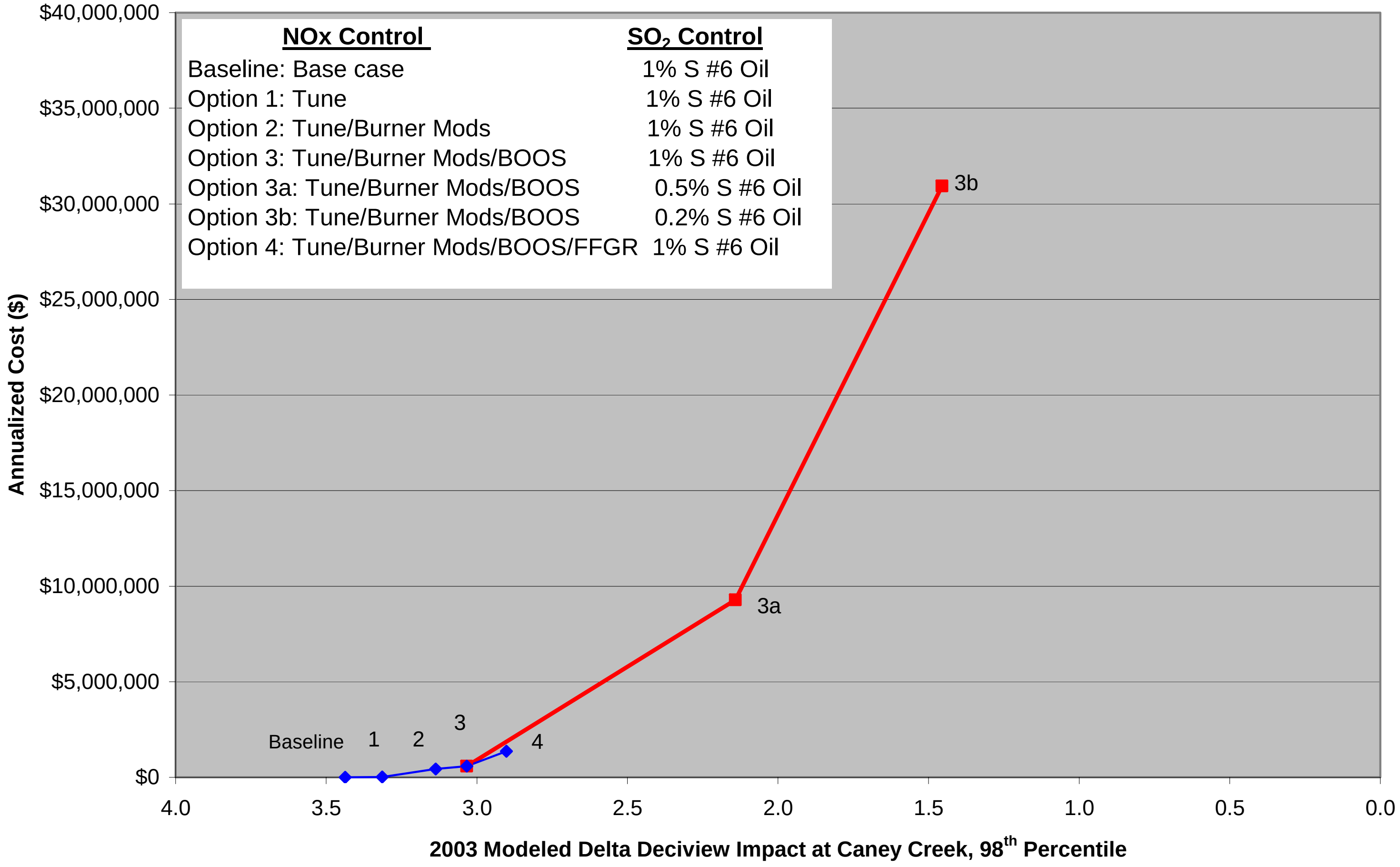
Table ES-3 Tabulation of Visibility Improvement and Annual Costs for Low Sulfur Oil Firing

Control Scenario Options	SO_2 Control Option	NOx Control Option	Annualized Cost ($/year)*	Incremental Cost from Previous Control Scenario ($/Year)	Delta deciviews from natural conditions (98th percentile day)	Incremental Cost Effectiveness ($/deciview Relative to the Previous Control Scenario)	Annual tons SO_2 removed	Incremental Cost Effectiveness ($/ton Relative to the Previous Control Scenario)
3	1.0% S #6 oil	Tuning, burner mods, BOOS	$583,386	$0	3.03	$0	--	-
3a	0.5% S #6 oil	Tuning, burner mods, BOOS	$9,288,837	$8,705,451	2.14	$9,759,475	1059	$8,224
3b	0.2% S #2 oil	Tuning, burner mods, BOOS	$30,938,520	$21,649,683	1.46	$31,559,305	1802	$29,120
* includes cost of BART NO_x controls								

Figure ES-3 Plot of Visibility Improvement vs. Annualized Control Cost for Low Sulfur Oil Firing

Lake Catherine -- Oil-Firing

Annualized Cost for Implementing Control vs Decrease in Visibility Impairment



NOx Control	SO$_2$ Control
Baseline: Base case	1% S #6 Oil
Option 1: Tune	1% S #6 Oil
Option 2: Tune/Burner Mods	1% S #6 Oil
Option 3: Tune/Burner Mods/BOOS	1% S #6 Oil
Option 3a: Tune/Burner Mods/BOOS	0.5% S #6 Oil
Option 3b: Tune/Burner Mods/BOOS	0.2% S #6 Oil
Option 4: Tune/Burner Mods/BOOS/FFGR	1% S #6 Oil

1.0 Introduction

1.1 Study Background

Federal regulations under 40 CFR 51 Appendix Y provide guidance and regulatory authority for conducting a visibility impairment analysis for designated eligible sources. The program requires the application of Best Available Retrofit Technology (BART) to those existing eligible sources in order to help meet the targets for visibility improvement at designated Class I areas.

The Lake Catherine plant's Unit 4, located near Jones Mills, Arkansas, has been identified as a BART-eligible source by the Arkansas Department of Environmental Quality (ADEQ) based on its preliminary review of the date of installation, emission rates and projected impacts on Class I areas. Class I areas within 300 km of the facility are shown in Figure 1-1 and include Caney Creek, Upper Buffalo, and Hercules Glades Wilderness Areas. The ADEQ has conducted preliminary BART exemption modeling of Unit 4, and these results indicate that the Unit is subject to BART review because the predicted visibility impacts exceed 0.5 delta deciviews in at least one Class I area.

Based upon a conference call held on November 17, 2006 with ADEQ and EPA Region 6, Entergy agreed to use the CENRAP screening meteorological database to conduct the visibility improvement modeling for the BART determination analysis. With some minor changes in the approach (use of a more recent CALPUFF version 5.765, level 060725), ENSR conducted the modeling consistent with the ADEQ approach.

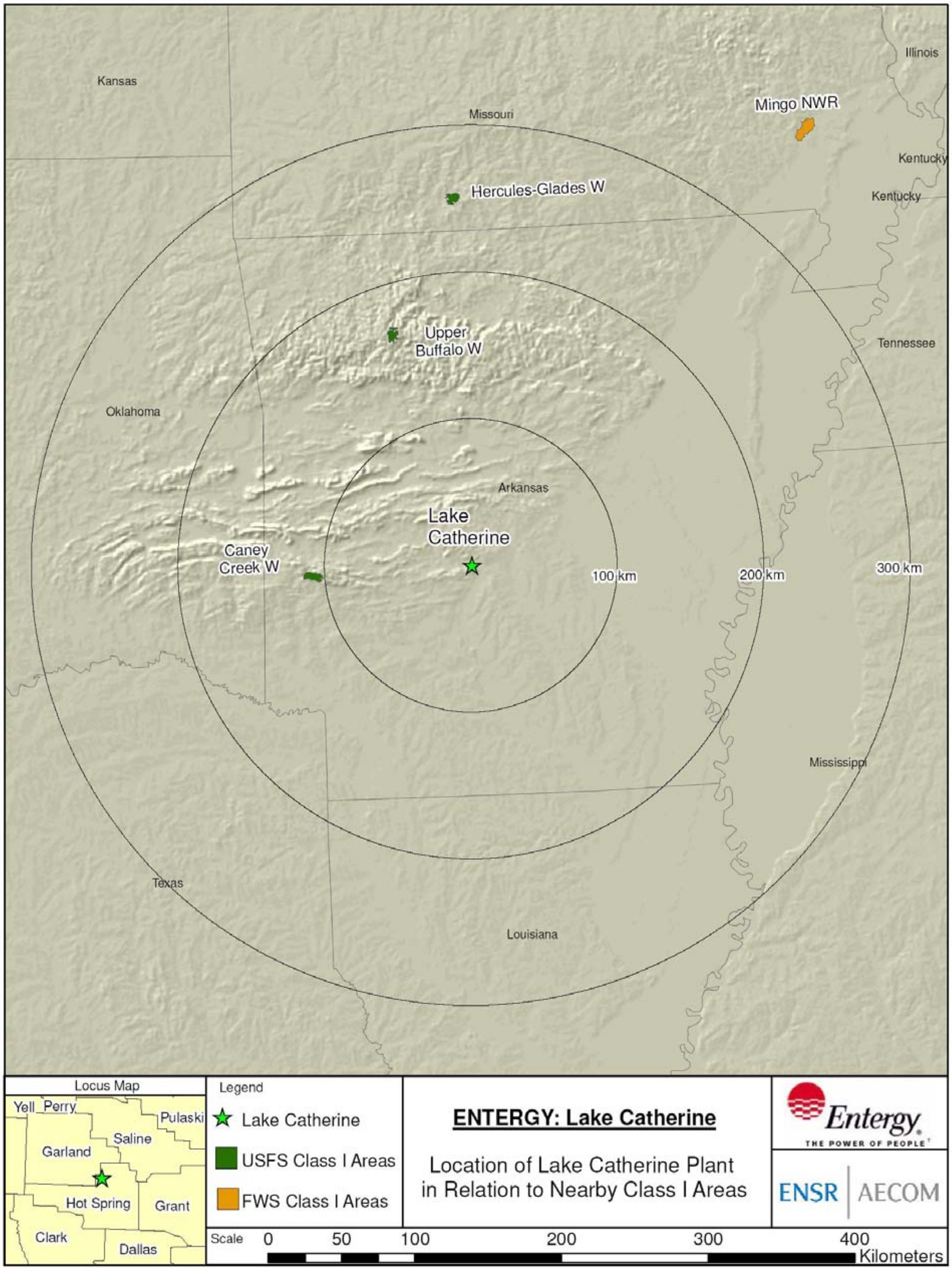
1.2 BART Determination Analysis Components

The site-specific BART determination analysis provided in this report includes the following components:

- A list of candidate retrofit controls that are being considered;
- A discussion of technical feasibility for retrofit of each candidate technology to the BART unit;
- A discussion of the control effectiveness of each feasible retrofit technology that is proposed as BART;
- A discussion of the non-air quality and energy impacts of each BART option, if applicable; and
- An evaluation of the impacts of each site-specific BART option, including
  - An estimate of the annualized cost for each of the BART options; and
  - An evaluation of the impacts on visibility for each of the BART options.

The regulation requires a formal choice of BART based on the above data, plus the degree of improvement in visibility (impacts) which may be reasonably anticipated to result from the installation or implementation of the proposed BART. Economic analysis and impacts on facility operation may be considered in the final BART decision-making process.

Figure 1-1 Class I Areas within 200 km of the Lake Catherine Plant



2.0 Background Data

2.1 Overview of BART Emission Unit

The BART-affected emission unit at the Lake Catherine plant is Unit 4, which came on-line in 1970. There are no near-term limitations on the useful life of this unit.

Unit 4 is a Combustion Engineering tilting tangential fired boiler with a maximum output of 552 MW. Unit 4 is permitted to burn natural gas and #6 oil. The Lake Catherine plant has a capacity less than 750 MW, so it is not subject to presumptive BART controls.

2.2 Recent Annual Emissions and Baseline Emissions

Table 2-1 provides a summary of the Lake Catherine Unit 4 emissions of SO_2 and NO_x for the period 2001-2005. The data were obtained from the EPA's Acid Markets database.

Table 2-1 Annual Emissions from Lake Catherine Unit 4 (2001-2005)

Year	Operating Hours	SO_2 emissions (tpy)	NO_x emissions (tpy)	Average NO_x emission rate (lb/MMBtu)	Heat Input (MMBtu)
2001	6,988	4.3	1,724.2	0.19	14,427,970
2002	5,651	3.7	1,421.1	0.20	12,415,550
2003	3,972	1.7	540.1	0.15	5,770,255
2004	1,534	0.6	140.0	0.12	1,904,101
2005	2,059	0.7	195.9	0.13	2,413,055

The maximum daily emissions of SO_2, NO_x, and PM_{10} used for the BART exemption modeling analysis were 3.3, 2,457, and 36.8 lb/hr, respectively. These values, derived from 2001-2003 data, feature a high NO_x emission rate that is an outlier case. The SO_2 and NO_x rates are based on maximum actual 24-hour emission rates, while the PM_{10} emission rates are based on AP-42 factors.

2.3 Site Characteristics

The cover photo depicts an aerial view of the Lake Catherine plant. Figure 2-2 shows a view of the site with the Unit 4 boiler and stack in the foreground. There are no site restrictions for NO_x combustion controls that are described in the next section.

Figure 2-1 Photo of the Lake Catherine Plant, with Unit 4 in the Foreground

2.4 Existing Emission Control Equipment at the Site

SO_2 and PM_{10} emissions are controlled by the use of pipeline-quality natural gas and the use of 1.0% sulfur fuel oil. NO_x emissions are controlled by good combustion practices.

2.5 BART Review

BART is being reviewed for only NO_x for Lake Catherine Unit 4 due to the minimal emissions of SO_2 and PM_{10}. Guidance for BART levels is described in EPA's BART rule Appendix Y to Part 51 - Guidelines for BART Determinations Under the Regional Haze Rule. It clearly advises that BART to be considered for NO_x control for gas/oil fired units is combustion control technology, not post combustion controls. Specifically, the EPA guidance states that "…for oil-fired and gas-fired EGUs larger than 200MW, we believe that installation of current combustion control technology to control NO_x is generally highly cost-effective and should be considered in your determination of BART for these sources. Many such units can make significant reductions in NO_x emissions which are highly cost-effective through the application of current combustion control technology." Accordingly, control options including various forms of current combustion control technology are considered in the BART determination analysis described in this report.

Appendix Y to Part 51 - Guidelines for BART Determinations Under the Regional Haze Rule discusses the manner in which incremental cost effectiveness of controls options should be evaluated. The rule states that "the incremental cost effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option." In this case, the "performance level" is the visibility improvement (reduction of delta deciviews) achieved by the control option. Therefore, the incremental cost effectiveness can be expressed with the following formula:

Incremental Cost Effectiveness (dollars per incremental reduction in delta deciviews) =

(Total annualized costs of control option N) - (Total annualized costs of control option N-1) ÷

(Control option N’s delta deciview improvement relative to base case - Control option N-1’s delta deciview improvement relative to base case).

The basic BART determination metric is therefore “dollars per deciview improvement”, for which results are provided in Section 5. Results for the more traditional dollars per ton removed are also provided.

3.0 Description of Emission Control Alternatives

3.1 NO_x Emission Controls

The techniques available to control NO_x from Lake Catherine Unit 4 are listed in Tables 3-1 for natural gas firing and Table 3-2 for fuel oil firing in order of increasing cost and control potential. The table also includes capital and operational and maintenance costs as well as short-term emission rates for NO_x. The base case represents the unchanged boiler, with a base emission rate of 0.483 lb/MMBtu. Cost and emissions information for the various control options is further documented in Appendix A, Table A-1. There are no expected non-air quality impacts from the combustion control options. The planned utilization of this unit for the future is about a capacity factor of 10% of the time. Past utilization of the unit has been an average capacity factor of 6.9% over the past 3 years.

All of the options described below are feasible, but they have various features, as discussed below. The main factors contributing to NO_x formation include combustion temperature, available oxygen, and fuel nitrogen content. The combustion modifications described below attempt to reduce NO_x formation by controlling the first two factors.

- Boiler tuning does not require any add-on equipment, but it simply is the result of boiler adjustments that minimize the formation of NO_x. Any prudent NO_x reduction measures should begin with a boiler tune-up to verify and optimize current boiler operating parameters. The fine-tuning of oxygen and fuel content in the combustion zone can improve efficiency and reduce NO_x emissions. Beyond simple tune-ups, systems can be installed to automatically monitor and trim oxygen and fuels for peak performance.
- Induced Flue Gas Recirculation (IFGR) involves extracting combustion product gases from the boiler's exhaust duct and inducing them into the forced draft fan inlet. Advantages are minimum installation time with no demolition/hazardous materials removal requirements, a fraction of the cost of alternate technologies for the same incremental control effectiveness, and relatively little or no impact or risk on performance and operation with the exception of a possible decrease in the maximum load capacity of the unit. IFGR is not applicable when combusting fuel oil because the flame stoichioemetrics are such that excess air must be increase when combusting fuel oil. The increase in excess air will produce NO_x which will offset the reduction in NO_x achieved by IFGR.

  Burners out of service (BOOS) is a form of fuel-staged combustion. The technique involves shutting off the fuel flow from one burner or more to create fuel rich and fuel lean zones and to lower the combustion temperature, thus achieving some NO_x emission control due to reduction of thermal NO_x (on the order of 10%). Extensive testing must be performed to determine the proper configuration and BOOS may require increased airflow.

  Overfire Air (OFA) – Furnace overfire air (OFA) technology involves the introduction of combustion air that is separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N_2 rather than NO_x. In this process, "primary" air (70-90%) is mixed with the fuel to produce a relatively low-temperature, oxygen-deficient, fuel-rich zone in which moderate amounts of fuel NO_x are formed. A "secondary" combustion air supply (10-30%) is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles, mounted above the burners. Combustion is completed at this increased flame volume. The relatively low-temperature secondary-stage limits the production of thermal NO_x, although the location of the injection ports and mixing of overfire air are critical to maintain efficient combustion. This technique is therefore challenging to use in a retrofit application, since effective mixing of overfire air with the primary combustion gases is critical to successfully reducing NO_x emissions and is highly dependent on original furnace design parameters such as residence time, inside geometry, and pressure drop.

The two staged combustion techniques mentioned above (BOOS and OFA) have been successfully employed to reduce NO_x emissions. However, it should be noted that each of these techniques requires that a higher level of combustion process control be exercised to prevent process upsets that can cause increased smoke, carbon monoxide, and/or hydrocarbon emissions. . OFA is not applicable when combusting fuel oil because of the potential to increase PM emissions which will offset NOx reductions.

Low NO_x burners (LNB) are designed to control fuel and air mixing at each burner in order to create larger and more branched flames. This reduces peak flame temperature and results in less NO_x formation. In addition, the improved flame structure also reduces the amount of oxygen available in the hottest part of the flame, thus improving burner efficiency. Low NO_x burners can be combined with other primary measures such as overfire air, burners out of service, or flue gas recirculation. However, the installation of low NO_x burners generally leads to higher operation and maintenance costs due to the increased complication of the systems required to operate them. LNB is not applicable when combusting fuel oil because of the potential to increase PM emissions which will offset NOx reductions.

Burner Modification – On oil-fired boilers, NO_x reductions, as well as improvements in other performance characteristics such as opacity and unburned carbon particulates, can be achieved through replacement of critical components of the burner hardware (normally the atomizer and impeller) with improved designs.

Forced Flue Gas Recirculation (FFGR) – Recirculating flue gas back to the combustion zone is a method of reducing NO_x emissions from gas and oil fired units. FFGR acts to reduce NO_x formation by reducing peak flame temperatures and by lowering the oxygen concentration in the combustion zone. For oil firing, where conversion of fuel-bound nitrogen contributes to NO_x, the reduced oxygen availability due to FGR also reduces the fraction of fuel nitrogen converted to NO_x. However, FFGR is typically much more effective in reducing NO_x for gas-fired applications than on oil-fired applications. In conventional applications, the recirculated flue gas is typically extracted from the boiler outlet duct upstream of the air heater. The flue gas is then returned through a separate duct and fan to the combustion air duct that feeds the windbox. The recirculated flue gas is mixed with the combustion air using air foils or other mixing devices in the duct.

Table 3-1 NO_x Control Options for Lake Catherine Unit 4 – Gas Firing

		% removal	lb/MMBtu	Total tons removed	Total costs per ton removed	Incremental tons removed	Incremental cost/ton removed
Baseline	Base Case	0%	0.483	--	--	--	--
Case 1	Tune	20.0%	0.386	215.2	$79	215.2	$79
Case 2	Tune/BOOS	42.1%	0.280	452.8	$272	237.6	$446
Case 3	Tune/BOOS/IFGR	69.6%	0.147	748.9	$531	296.0	$929
Case 4	Tune/BOOS/IFGR/OFA	84.0%	0.077	904.3	$1,701	155.4	$7,335
Case 5	Tune/BOOS/IFGR/OFA/LNB	88.6%	0.055	953.2	$3,757	49.0	$41,739

Tune	Combustion Tuning
IFGR	Induced Flue Gas Recirculation
BOOS	Burners Out of Service
OFA	Overfire Air
LNB	Low NO_x Burners Review next issue

Table 3-2 NO_x Control Options for Lake Catherine Unit 4 – Oil Firing

		% removal	lb/MMBtu	Total tons removed	Total costs per ton removed	Incremental tons removed	Incremental cost/ton removed
Baseline	Base Case	0.0%	0.483	--	--	--	--
Case 1	Tune	20.0%	0.386	220.0	$73	220.0	$73
Case 2	Tune/boiler mods	42.1%	0.280	462.9	$937	242.9	$1,720
Case 3	Tune/boiler mods/BOOS	47.6%	0.253	523.5	$1,115	60.5	$2,469
Case 4	Tune/boiler mods/BOOS/FFGR	54.6%	0.219	600.1	$2,262	76.6	$10,101

Tune	Combustion Tuning
Boiler mods	Boiler Modifications
FFGR	Forced Flue Gas Recirculation
BOOS	Burners Out of Service

3.2 SO_2 Emission Control

The use of natural gas and the 1% limit of sulfur in fuel oil effectively limits the SO_2 emissions from Lake Catherine Unit 4. No further BART analysis is required for SO_2. The emission rate to be used in the modeling for natural gas firing corresponds to the peak daily emission rate in 2001-2003: 0.42 g/s. For oil firing, AP-42 factors with 1%, 0.5% and 0.2% sulfur residual oil results in an SO_2 emission rate of 664.9 g/s, 360.4 g/s, and 146.5 g/s, respectively. Cost and emissions information for the various control options is presented in Table 3-3 and further documented in Appendix A, Table A-3.

Table 3-3 SO_2 Control Options for Lake Catherine Unit 4 – Oil Firing

SO_2 Control	lb/hr	TPY @ 10% util	Total TPY Removed	Average cost/ ton	Annual Cost	Incremental cost/ton removed
Base case - 1% S #6 oil	5277	2311	--	--	--	--
0.5% S #6 oil	2860	1253	1059	$8,224	$8,705,451	$8,224
0.2% S #2 oil	1163	509	1802	$16,845	$30,355,134	$29,120

3.3 PM_{10} Emission Control

The use of natural gas and the 1% limit of sulfur in fuel oil effectively limits the PM_{10} emissions from Lake Catherine Unit 4. No further BART analysis is required for PM_{10}. The emission rate to be used in the modeling for natural gas firing corresponds to the peak daily emission rate in 2001-2003: 36.8 lb/hr. For oil firing, AP-42 factors with 1%, 0.5%, and 0.2% sulfur residual oil results in a filterable and condensable PM_{10} emission rates, listed in Table 3-3. These emissions have been speciated into filterable (coarse and fine inorganic matter and elemental carbon), and condensable PM_{10} using National Park Service-provided guidance. The details of the speciation are provided separately in the computer modeling archive.

Table 3-4 PM_{10} Emission Rates for Lake Catherine Unit 4 – Oil Firing

	PM_{10} Filterable lb/hr	**PM_{10} Condensable Lb/hr**
1.0% S #6 oil	420	50
0.5% S #6 oil	288	55
0.2% S #2 oil	74	48

4.0 Selection of Control Scenarios for Modeling

Visibility impacts have been evaluated with modeling based on maximum 24-hour emission rates for SO_2, NO_x, and PM_{10} for each option the criteria pollutants. For evaluating visibility improvement as a result of installing the BART options, the first step is to identify the level of improvement in the 24-hour maximum emissions, from the baseline to the proposed new limits. Table 4-1 lists each control option, as applied to each unit for the separate NO_x controls for natural gas firing; Table 4-2 provides similar information for fuel oil firing. The applicable emission rate and percent emissions reduction from the 24-hour baseline emission rate used for modeling are also listed. The assumed typical 100% load heat input rates for the emission calculations are 5089.7 MMBtu/hr for natural gas firing and 5203 MMBtu/hr for fuel oil firing.

Table 4-1 NO_x Emission Rates for Visibility Evaluation for Each Considered Option: Natural Gas Firing

Unit	Control Option	Baseline Peak 24-hour Emissions (lb/hour)	Reduction from Baseline Peak 24-hour Rate (%)	Future Peak 24-hour Emission Rate (lb/hour)
4	1) Base case	2456.7	0.0%	2456.7
4	2) Boiler tuning	2456.7	20.0%	1965.3
4	3) Tune, BOOS	2456.7	42.1%	1422.8
4	4) Tune, BOOS,IFGR	2456.7	69.6%	746.9
4	5) Tune, BOOS,IFGR, OFA	2456.7	84.0%	392.2
4	6) Tune, BOOS,IFGR, OFA, LNB	2456.7	88.6%	280.4

Table 4-2 NO_x Emission Rates for Visibility Evaluation for Each Considered Option: Fuel Oil Firing

Unit	Control Option	Baseline Peak 24-hour Emissions (lb/hour)	Reduction from Baseline Peak 24-hour Rate (%)	Future Peak 24-hour Emission Rate (lb/hour)
4	1) Base case	2511.4	0.0%	2511.4
4	2) Boiler tuning	2511.4	20.0%	2009.1
4	3) Tune, boiler mods	2511.4	42.1%	1454.5
4	4) Tune, boiler mods, BOOS	2511.4	47.6%	1316.3
4	5) Tune, boiler mods, BOOS, FFGR	2511.4	54.6%	1141.4

The baseline modeling visibility impact was determined for each modeling year (2001-2003). The modeling results are discussed in the next section.

5.0 Selection of the Best Alternative for BART Control

The results of the CALPUFF visibility improvement modeling while combusting natural gas, along with the cost control information, are provided in Table 5-1 for the worst-case year and Class I area for 10% capacity factor. Results of modeling for other years and Class I areas are provided separately in the computer modeling archive. These results are also provided in a plot (Figure 5-1) showing the visibility improvement vs. the control costs. One key feature of the plot is that the regional haze reduction relative to natural background is predicted to be about 0.6 delta deciviews from the use of boiler tuning, BOOS, and IFGR for an annualized cost of about $400,000. The next control option (OFA) results in a much higher the cost per deciview improvement, with only 0.2 delta deciview improvement. Beyond that scenario, the addition of overfire air increases the cost by a factor of about 8 per deciview improvement. The addition of low-NO_x burners increases the cost yet again by about a factor of about 6 per deciview improvement. For a unit that is predicted to be dispatched about 10% of the time, it is apparent that due to significant cost increases, reduced benefits, and complexities in the retrofits beyond BOOS and IFGR as described in this report, BART is determined to be a combination of tuning, BOOS and IFGR (Option 3).

The results of the CALPUFF visibility improvement modeling while combusting 1% sulfur fuel oil, along with the cost control information, are provided in Table 5-2 for the worst-case year and Class I area. These results are also provided in a plot (Figure 5-2) showing the visibility improvement vs. the control costs for a 10% capacity factor. Based on the modeling results of all NO_x control options with 1% sulfur oil, BART is determined to be a combination of boiler tuning with modifications and BOOS (Option 3). Option 3 then was modeled with the lower sulfur oil options. The CALPUFF visibility improvement modeling results along with the cost control information are provided in Table 5-3. Figure 5-3 shows the visibility improvement vs. the control costs of all NO_x control options with 1% sulfur oil (blue line) and BART Option 3 with 0.5% and 0.2% sulfur oil (red line). One key feature of these plots is that the incremental cost per deciview improvement increases markedly beyond Option 3 with 1% sulfur oil. It is apparent that due to significant cost increases, reduced benefits, and complexities in the retrofits beyond the tuning, boiler modifications, and BOOS as described in this report, BART is determined to be a combination of tuning, boiler modifications, and BOOS with 1% sulfur oil.

Table 5-1 Tabulation of Visibility Improvement and Annual Costs for BART Control Option for Natural Gas Firing

Control Scenario Options	Description	Annualized Cost ($/year)	Incremental Cost from Previous Control Scenario ($/Year)	Delta deciviews from natural conditions (98th percentile day)	Incremental Cost Effectiveness ($/deciview Relative to the Previous Control Scenario)	Annual tons NO_x removed	Incremental Cost Effectiveness ($/ton Relative to the Previous Control Scenario)
Baseline	Base case	--	--	1.56	--	--	--
1	Boiler tuning	$17,016	$17,016	1.30	$64,947	215.2	$79
2	Tune, BOOS	$122,956	$105,940	0.99	$346,208	452.8	$446
3	Tune, BOOS,IFGR	$397,923	$274,967	0.56	$630,659	748.9	$929
4	Tune, BOOS,IFGR, OFA	$1,537,731	$1,139,807	0.34	$5,228,474	904.3	$7,335
5	Tune, BOOS,IFGR, OFA, LNB	$3,581,027	$2,043,297	0.27	$30,048,478	953.2	$41,739

Figure 5-1 Plot of Visibility Improvement vs. Annualized Control Cost for BART Options for Natural Gas Firing

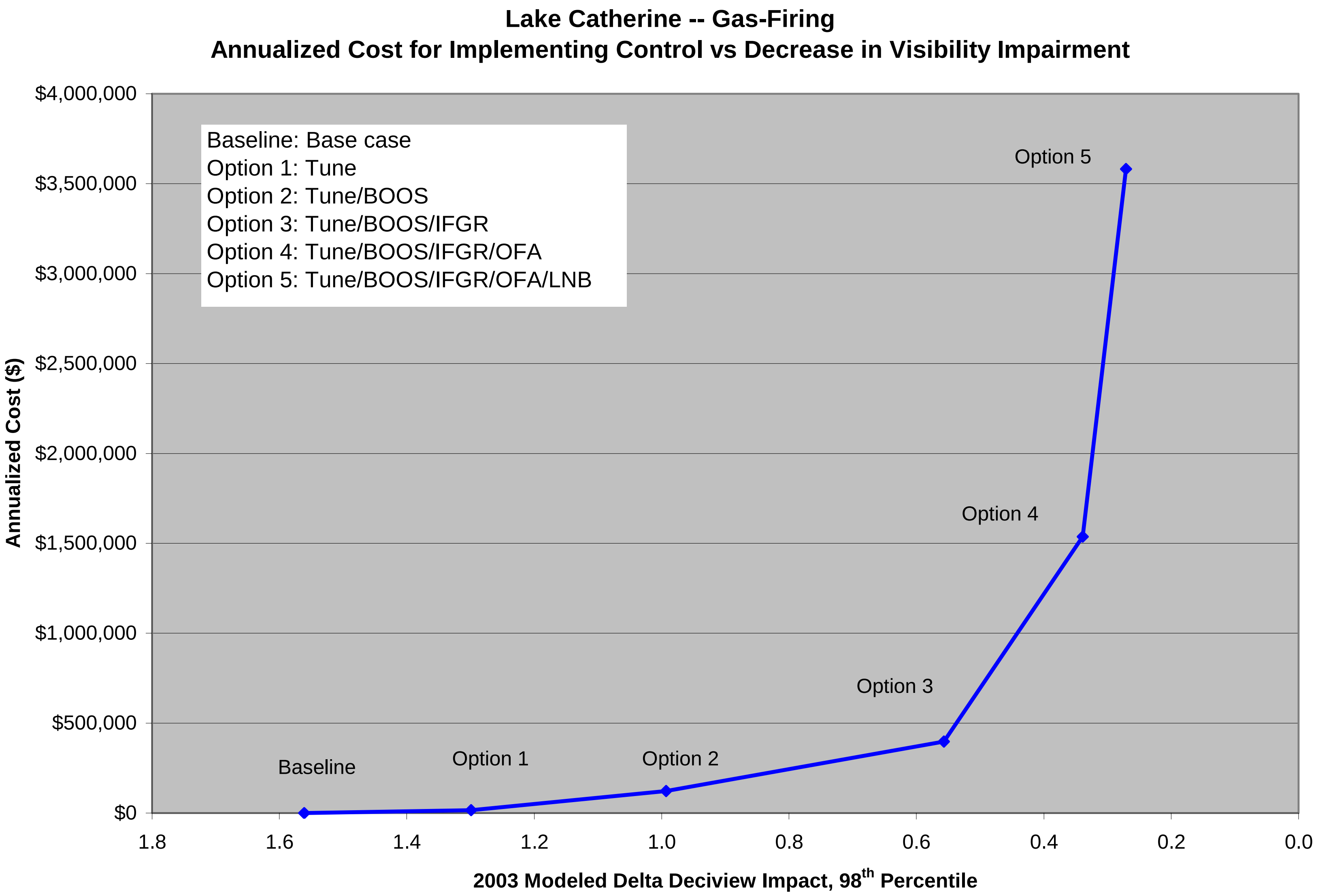


Table 5-2 Tabulation of Visibility Improvement and Annual Costs for BART Control Option for Oil Firing

Control Scenario Options	Description	Annualized Cost ($/year)	Incremental Cost from Previous Control Scenario ($/Year)	Delta deciviews from natural conditions (98th percentile day)	Incremental Cost Effectiveness ($/deciview Relative to the Previous Control Scenario)	Annual tons NO_x removed	Incremental Cost Effectiveness ($/ton Relative to the Previous Control Scenario)
Baseline	Base case	--	--	3.44	--	--	--
1	Boiler tuning	$16,000	$16,000	3.31	$130,085	220.0	$73
2	Tuning, burner mods	$433,934	$417,933	3.14	$2,347,939	462.9	$1,720
3	Tuning, burner mods, BOOS	$583,386	$149,452	3.03	$1,450,989	523.5	$2,469
4	Tune, burner mods, BOOS, FFGR	$1,357,123	$773,737	2.90	$5,906,393	600.1	$10,101

Table 5-3 Tabulation of Visibility Improvement and Annual Costs for Low Sulfur Oil

Control Scenario Options	SO_2 Control Option	NOx Control Option	Annualized Cost ($/year), including NO_x BART control costs	Incremental Cost from Previous Control Scenario ($/Year)	Delta deciviews from natural conditions (98th percentile day)	Incremental Cost Effectiveness ($/deciview Relative to the Previous Control Scenario)	Annual tons SO_2 removed	Incremental Cost Effectiveness ($/ton Relative to the Previous Control Scenario)
3	1.0% S #6 oil	Tuning, burner mods, BOOS	$583,386	$0	3.03	$0	--	-
3a	0.5% S #6 oil	Tuning, burner mods, BOOS	$9,288,837	$8,705,451	2.14	$9,759,475	1059	$8,224
3b	0.2% S #2 oil	Tuning, burner mods, BOOS	$30,938,520	$21,649,683	1.46	$31,559,305	1802	$29,120

Figure 5-2 Plot of Visibility Improvement vs. Annualized Control Cost for BART Options for Fuel Oil Firing

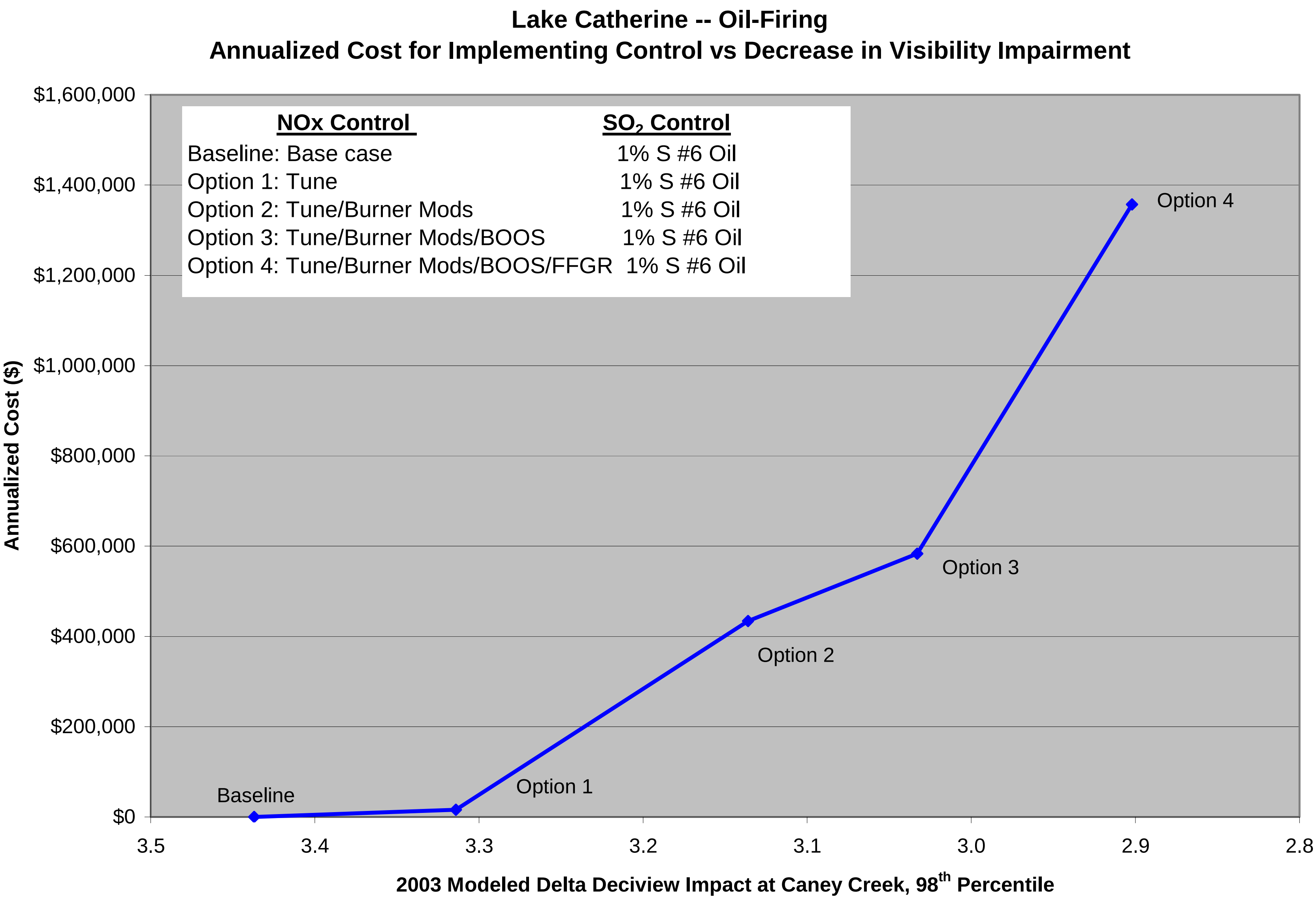
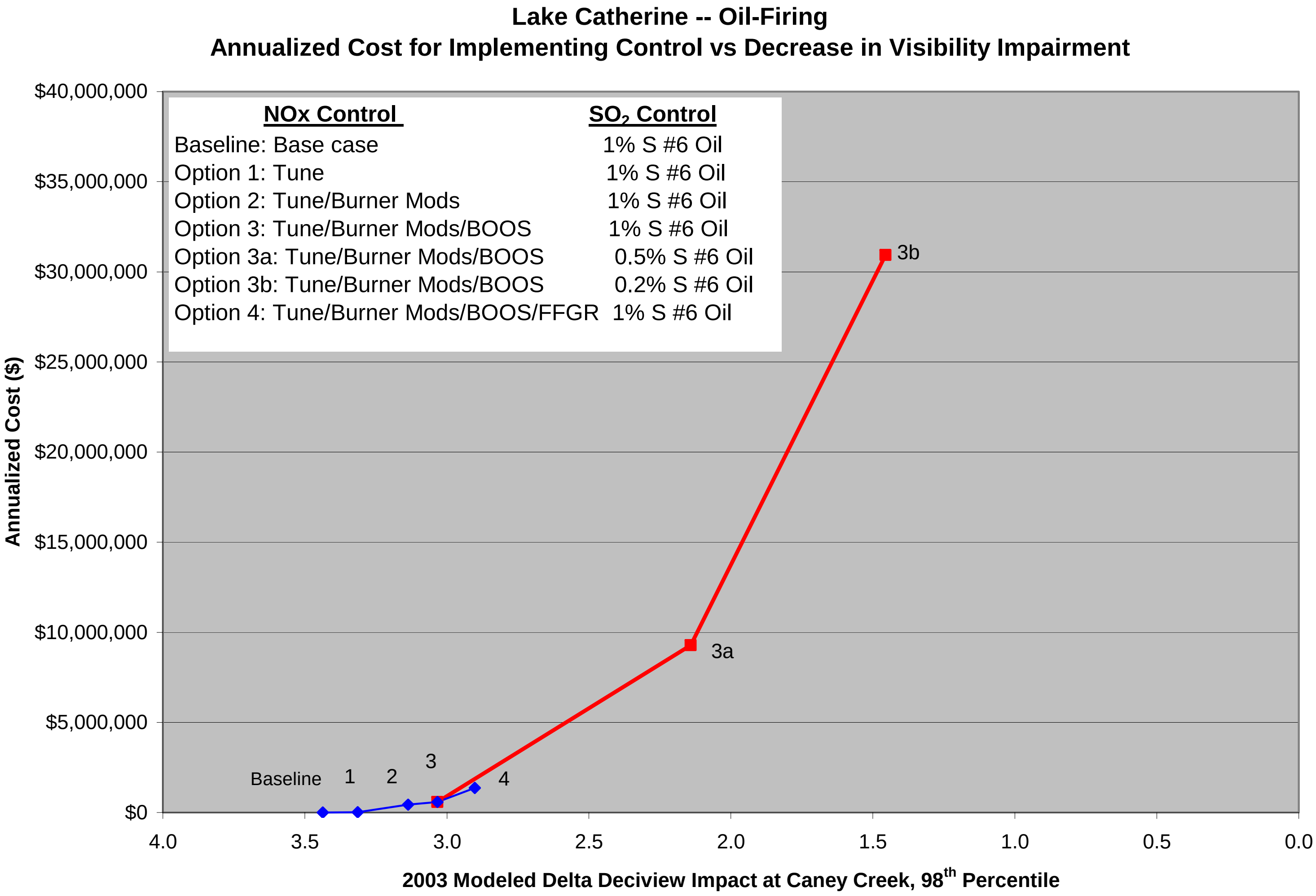


Figure 5-3 Plot of Visibility Improvement vs. Annualized Control Cost for Low Sulfur Fuel Oil



Appendix A

Cost and Emissions Estimates for NO_X and SO_2 Control Options

Table A-1 Lake Catherine Unit 4 NO$_x$ Control Options and Cost - Gas

NO$_x$ **Control**	**% Removal**	**lb/MMBtu**	**lb/hr**	**TPY @ 10% util**	**TPY Removed**	**Average cost/ton**	**Annual Cost**	**Incr. tons Removed**	**Incr. Cost/ton**	**Incr. Cost**
Base Case	0%	0.483	2456.7	1076.0	0.0	$0	$0	0.0	$0	$0
Tune	20.0%	0.386	1965.3	860.8	215.2	$79	$17,016	215.2	$79	$17,016
Tune/BOOS	42.1%	0.280	1422.8	623.2	452.8	$272	$122,956	237.6	$446	$105,940
Tune/BOOS/IFGR	69.6%	0.147	746.9	327.2	748.9	$531	$397,923	296.0	$929	$274,967
Tune/BOOS/IFGR/OFA	84.0%	0.077	392.2	171.8	904.3	$1,701	$1,537,731	155.4	$7,335	$1,139,807
Tune/BOOS/IFGR/OFA/LNB	88.6%	0.055	280.4	122.8	953.2	$3,757	$3,581,027	49.0	$41,739	$2,043,297

Table A-2 Lake Catherine Unit 4 NO$_x$ Control Options and Cost – Oil

NO$_x$ **Control**	**% Removal**	**lb/MMBtu**	**lb/hr**	**TPY @ 10% util**	**TPY Removed**	**Average cost/ton**	**Annual Cost**	**Incr. tons Removed**	**Incr. Cost/ton**	**Incr. Cost**
Base case	0.0%	0.483	2511.4	1100.0	0.0	$0	$0	0.0	$0	$0
Tuning	20.0%	0.386	2009.1	880.0	220.0	$73	$16,000	220.0	$73	$16,000
Tuning/burner mods	42.1%	0.280	1454.5	637.1	462.9	$937	$433,934	242.9	$1,720	$417,933
Tuning/burner mods/BOOS	47.6%	0.253	1316.3	576.5	523.5	$1,115	$583,386	60.5	$2,469	$149,452
Tuning/burner mods/BOOS/FFGR	54.6%	0.219	1141.4	499.9	600.1	$2,262	$1,357,123	76.6	$10,101	$773,737

Table A-3 Lake Catherine Unit 4 SO_2 Control Options and Cost – Oil

SO_2 Control	Fuel gallon/hr	lb/hr	TPY @ 10% util	Incr. TPY Removed	Incr. cost/ton	Annual costs of fuel switch	Annual Cost
Base case - 1% S #6 oil	33,611	5277	2311	--	--	$31,540,170	--
0.5% S #6 oil	36,436	2860	1253	1059	$8,224	$40,245,621	$8,705,451
0.2% S #2 oil	37,032	1163	509	743	$29,120	$61,895,304	$30,355,134

Calculation Method Used In BART Determination

Standard engineering economic analysis is used to convert all costs to equivalent levelized annual costs so that the pollution control cost effectiveness (in dollars per ton of pollutant controlled) may be calculated for comparison with other control options.

Definition of Levelized Annual Cost - For reference, levelized costs are related directly to the present value of a scenario, and they are equivalent to the uniform annual cost that has the same present value as the actual annual costs over the life of the unit. Levelized costs are essentially the weighted average of the actual annual costs. Annual costs will increase each year due to escalation of the costs of specific commodities and due to the general inflation rate. Economic factors are applied to the three components of the total levelized cost:

- Fixed O&M Costs - operating and administrative labor and maintenance costs
- Variable - consumable costs that vary with plant operating load, such as auxiliary power, chemicals, water, solid waste disposal, etc.
- Fixed Carrying Charges - the charges associated with financing the capital investment.

When these components are added together, they provide the total levelized cost for each technology option.

Variable and Fixed Operating Cost Levelization – The annual costs for all variable and fixed operating cost components are calculated based on the system material balance and system operating assumptions. Operating labor cost is based on the number of personnel that need to be added to the plant staff to operate the new equipment and subsystems. Maintenance costs are calculated as a percentage of the total installed cost of the equipment, including both labor and materials costs. These first-year annual costs are then multiplied by a “levelization factor” to calculate the levelized annual cost contribution of the variable costs. The levelization factor is calculated using the following equation:

$$\left[\frac{(1+i)}{(i-e)}\right] \times \left[\frac{(1+i)^n - (1+e)^n}{(1+i)^n}\right]$$

where i = discount rate
e = annual escalation rate
n = number years of plant operating life

Fixed Capital Charges – These costs represent the carrying charge associated with financing the Total Capital Requirement (TCR) for the emissions control system retrofit. The TCR cost estimates include both direct costs (equipment purchase costs, sales taxes, freight, installation costs, foundations, supports, field erection, electrical, piping, insulation, and painting) and indirect costs (engineering, construction, contractor fees, start-up, performance tests, contingencies, and interest during construction).

Total Capital Requirement (TCI) = Direct Capital Cost + Indirect Capital Cost

The fixed charge rate is the sum of the return on equity, income tax (both current and deferred), book depreciation, property tax, and insurance. It is equivalent to the amount of revenue per dollar of Total Capital Requirement that must be collected from customers in order to pay the carrying charges on that investment.

The Fixed Charge Rate is multiplied times the TCR to obtain a dollar amount, typically a levelized annual cost over a specified operating life of the new equipment. This factor is also called the carrying charge rate.

Levelized Annual Capital Recovery (ACR) = FCR x TCR

The cost effectiveness of a control technology is calculated by dividing the total annualized costs of the control technology by the total tons of pollutant emissions removed by the control equipment per year.

Levelized Control Cost = $\frac{\text{Levelized ACR + Levelized Fixed and Variable Annual Cost}}{\text{Annual Tons of } SO_2 \text{ Removed}}$

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Entergy Services, Inc.

BART Analysis for the White Bluff Steam Electric Station

ENSR Corporation
December 2006
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BART Analysis for the White Bluff Steam Electric Station

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ENSR Corporation
December 2006
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Executive Summary

Units 1 and 2 of Entergy's White Bluff Steam Electric Station in Redfield, Arkansas have been identified as BART-eligible sources by the Arkansas Department of Environmental Quality (ADEQ). CALPUFF modeling for BART exemption results indicate that these BART-eligible units could collectively have a potential visibility impact above the 0.5 deciview exemption threshold, meaning that a site-specific BART analysis is required. This report summarizes the BART analysis performed for White Bluff Units 1 and 2.

White Bluff Units 1 and 2 are Combustion Engineering tilting tangential fired boilers with a maximum power rating of 850 megawatts each. Since the plant capacity exceeds 750 MW, this plant has presumptive BART limits (discussed below) that apply. Both units burn sub-bituminous coal during normal operations. An auxiliary boiler at the plant is used only for startup, so it is not subject to BART.

Class I areas within 300 km of the facility include Caney Creek, Upper Buffalo, and Hercules Glades Wilderness Areas. Entergy asked ENSR Corporation to develop a refined meteorological database for CALPUFF modeling that includes the White Bluff plant and the three Class I areas mentioned above; this information has been submitted to the ADEQ separately.

Most of the visibility-causing emissions from Units 1 and 2 are due to SO_2 and NO_x, while PM_{10} emissions are well-controlled with electrostatic precipitators. Therefore, the BART analysis addresses only SO_2 and NO_x controls. The presumptive BART levels described in EPA's BART Rule, Appendix Y to Part 51 indicate that for this facility, the SO_2 emission limit should be 0.15 lb/MMBtu and the NO_x emission limit ranges between 0.15 and 0.28 lb/MMBtu, depending upon the type of coal (with the currently-used sub-bituminous coal, the presumptive NO_x emission limit is 0.15 lb/MMBtu).

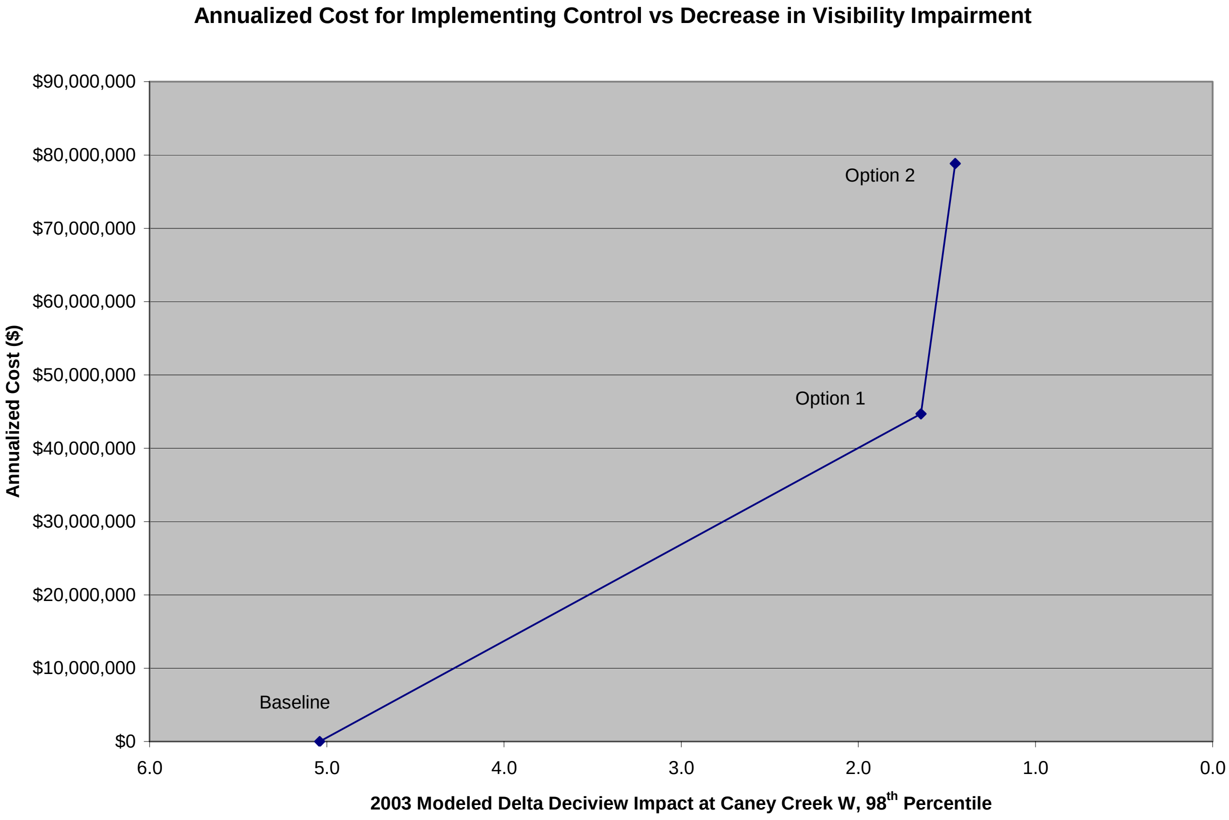
The NO_x BART option considered a combination of controls that achieves the presumptive limit: boiler tuning, overfire air (OFA), and low-NO_x burners (LNB). Entergy developed costs per ton removed for each of these control options. For SO_2 BART options considered both wet (95% control) and dry (92% control) scrubbing, both of which can attain the presumptive limit of 0.15 lb/MMBtu for SO_2 emissions, even with higher sulfur Eastern coal.

The results of the CALPUFF visibility improvement modeling for the BART options, along with the control cost information, is provided in Table ES-1 for the worst-case year (2003) and Class I area (Caney Creek). These results are also provided in a plot (Figure ES-1) showing the visibility improvement vs. the control costs (incremental cost effectiveness analysis). Due to the fact that dry scrubbing SO_2 controls plus a fabric filter system are about twice as expensive as wet scrubbing controls to retrofit, and the additional visibility improvement with dry scrubbing is relatively small (or even less if the fuel supply is unchanged), BART is determined to be a combination of tuning, OFA, and LNB for NO_x and wet scrubbing for SO_2.

Table ES-1 Tabulation of Visibility Improvement and Annual Costs for Each Control Option

Control Scenario Options	Description	Delta deciviews from Natural Conditions (98th Percentile Day)	Annualized Cost ($/Year)	Incremental Cost from Previous Control Scenario ($/Year)	Incremental Cost Effectiveness ($/deciview Relative to the Previous Control Scenario)
Baseline	Base case	5.040	--	--	--
1	NO_x: Tune, OFA, LNB SO_2: wet scrubbing	1.646	$44,696,851	$44,696,851	$13,169,373
2	NO_x: Tune, OFA, LNB SO_2: dry scrubbing	1.453	$78,856,392	$34,159,541	$176,992,442

Figure ES-1 Plot of Visibility Improvement vs. Annualized Control Cost for BART Options



1.0 Introduction

1.1 Study Background

Federal regulations under 40 CFR 51 Appendix Y provide guidance and regulatory authority for conducting a visibility impairment analysis for designated eligible sources. The program requires the application of Best Available Retrofit Technology (BART) to those existing eligible sources in order to help meet the targets for visibility improvement at designated Class I areas. For units with a capacity greater than 200 MW at a facility with a capacity greater than 750 MW 40CFR51 list mandatory presumptive limits for NO_x and SO_2 emissions.

The White Bluff Steam Electric Station's Units 1 and 2, located near Redfield, Arkansas, have been identified as BART-eligible sources by the Arkansas Department of Environmental Quality (ADEQ) based on its preliminary review of the date of installation, emission rates and projected impacts on Class I areas. Class I areas within 300 km of the facility are shown in Figure 1-1 and include Caney Creek, Upper Buffalo, and Hercules Glades Wilderness Areas. The ADEQ has conducted preliminary BART exemption modeling of Units 1 and 2, and these results indicate that the units are subject to BART review because the collective predicted visibility impacts exceed 0.5 delta deciviews in at least one Class I area.

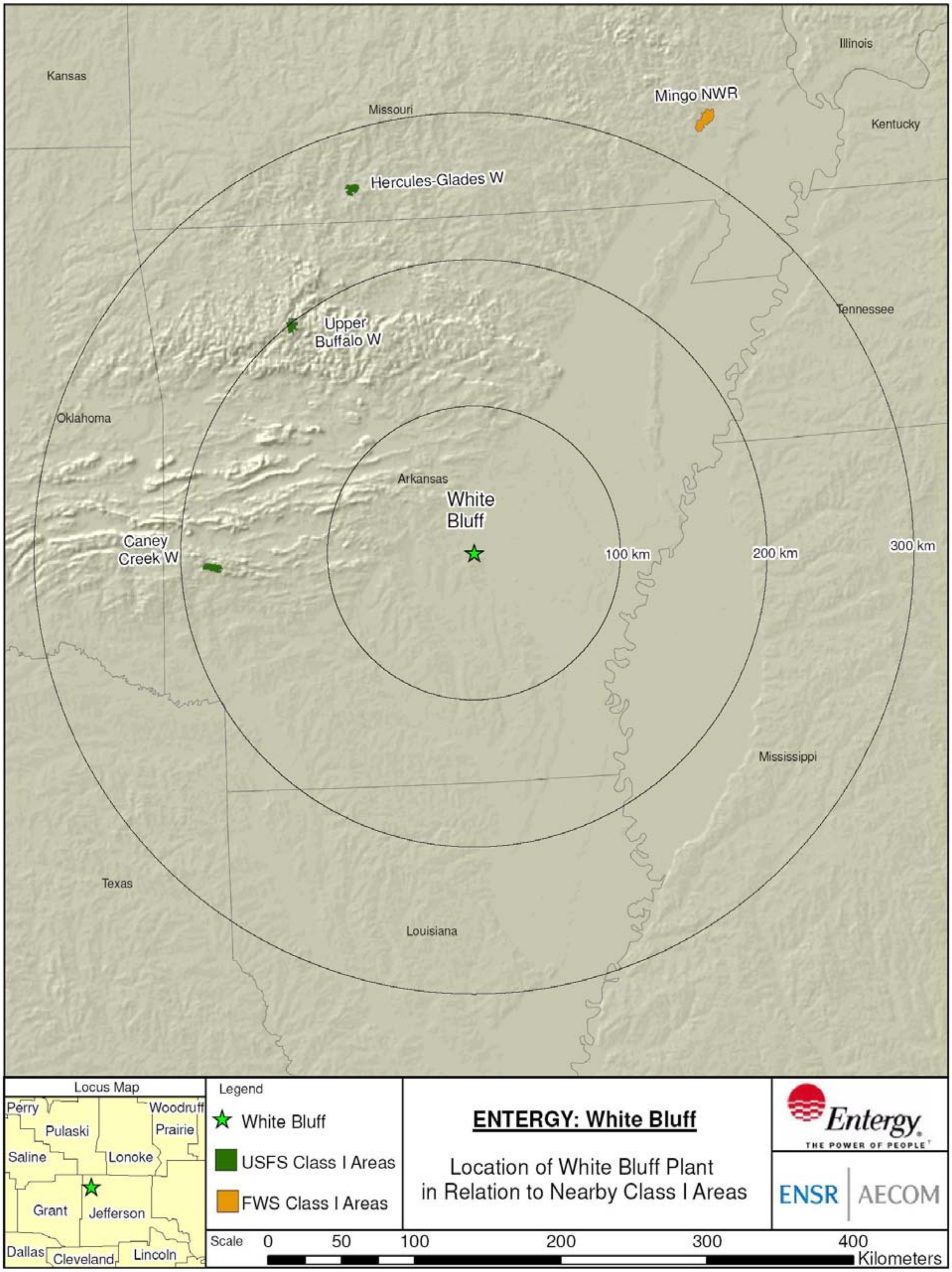
Based upon a conference call held on November 17, 2006 with ADEQ and EPA Region 6, Entergy agreed to use the CENRAP screening meteorological database to conduct the visibility improvement modeling for the BART determination analysis. With some minor changes in the approach (correction of source location and use of a more recent CALPUFF version 5.765, level 060725), ENSR conducted the modeling consistent with the ADEQ approach.

1.2 BART Determination Analysis Components

The site-specific BART determination analysis provided in this report includes the following components:

- A list of candidate retrofit controls that are being considered to meet presumptive limits;
- A discussion of technical feasibility for retrofit of each candidate technology to the BART units;
- A discussion of the control effectiveness of each feasible retrofit technology that is proposed as BART;
- A discussion of the non-air quality and energy impacts of each BART option;
- An evaluation of the impacts of each site-specific BART option, including
  - An estimate of the annualized cost for each of the BART options;
  - An evaluation of the impacts on visibility for each of the BART options;

Figure 1-1 Class I Areas within 200 km of the White Bluff Plant



2.0 Background Data

2.1 Overview of BART Emission Unit

The BART-affected emission units at the White Bluff plant are Units 1 and 2. There are no near-term limitations on the useful lives of these units, which came on line in 1980 and 1981, respectively. They are eligible for BART because construction began at the site in 1974, so the units were "in existence" as of August 7, 1977.

White Bluff Units 1 and 2 are Combustion Engineering tilting tangential fired boilers with a maximum power rating of 850 megawatts each. Since the plant capacity exceeds 750 MW, this plant has presumptive BART limits (discussed below) that apply. Both units burn sub-bituminous coal during normal operations. An auxiliary boiler at the plant is used only for startup, so it is not subject to BART.

2.2 Recent Annual Emissions and Baseline Emissions

Table 2-1 provides a summary of the White Bluff emissions of SO_2 and NO_x for the period 2001-2005. The data were obtained from the EPA's Acid Markets database.

Table 2-1 Annual Emissions from White Bluff Units 1 and 2 (2001-2005)

Year	Operating Hours (Units 1 / 2)	SO_2 Emissions (tpy)	Average SO_2 Emission Rate (lb/MMBtu)	NO_x Emissions (tpy)	Average NO_x Emission Rate (lb/MMBtu)	Heat Input (MMBtu)
2001	6,693 / 7,459	16,679.1 / 20,036.7	0.658 / 0.648	8,609.0 / 10,550.9	0.339 / 0.341	50,728,492 / 61,832,866
2002	7,658 / 6,462	20,816.4 / 13,335.0	0.700 / 0.645	10,658.5 / 7,046.2	0.359 / 0.341	59,446,752 / 41,326,911
2003	8,102 / 7,288	21,653.4 / 17,650.3	0.704 / 0.684	10,854.9 / 8,161.2	0.353 / 0.316	61,475,950 / 51,589,676
2004	7,647 / 8,124	21,518.6 / 22,979.4	0.723 / 0.737	9,196.0 / 9,010.9	0.309 / 0.289	59,551,468 / 62,328,108
2005	7,886 / 7,792	17,394.1 / 17,495.8	0.660/ 0.648	8,268.0 / 7,994.7	0.313 / 0.296	52,698,342 / 53,987,767

The maximum daily emissions of SO_2, NO_x, and PM_{10} used for the BART exemption modeling analysis were 7,763.3, 4,371.7, and 217.4 lb/hr, respectively, for Unit 1 and 7,825.0, 4,730.8, and 234.7 lb/hr for Unit 2. These values were derived from 2001-2003 data. The SO_2 and NO_x rates were based upon maximum actual 24-hour emission rates, while the PM_{10} emission rates were based on AP-42 factors.

2.3 Site Characteristics

The cover photo depicts an aerial view of the White Bluff plant. Figure 2-1 shows a view of the site with the boiler buildings for Units 1 and 2 and the combined stack. There are no site restrictions for application of the SO_2 or NO_x controls that are evaluated in the next section.

Figure 2-1 Photo of the White Bluff Steam Electric Station

2.4 Existing Emission Control Equipment at the Site

Currently, SO_2 emissions are controlled by the use of low-sulfur coal. NO_x emissions are controlled by good combustion practices. PM_{10} emissions are controlled with electrostatic precipitators.

2.5 BART Review

BART is being reviewed for both SO_2 and NO_x for White Bluff. PM_{10} controls are already optimized with the use of electrostatic precipitators, so no retrofit controls are considered for PM_{10}. The presumptive BART levels are described in EPA's BART Rule, Appendix Y to Part 51 - Guidelines for BART Determinations Under the Regional Haze Rule. For SO_2, the presumptive control level is 0.15 lb/MMBtu, which can be attained via either wet scrubbing (assuming up to 95% control efficiency) or by semi-dry scrubbing. For NO_x controls, the presumptive limit for tangentially-fired units with sub-bituminous (Powder River Basin) coal is 0.15 lb/MMBtu, while it is 0.28 lb/MMBtu for use of bituminous coal. The EPA guidance states that for units without post-combustion NO_x controls, the use of combustion controls should be able to meet the presumptive limits. This issue is discussed further in Section 3.

Appendix Y to Part 51 - Guidelines for BART Determinations Under the Regional Haze Rule discusses the manner in which incremental cost effectiveness of controls options should be evaluated. The rule states that "the incremental cost effectiveness calculation compares the costs and performance level of a control option to those of the next most stringent option." In this case, the "performance level" is the visibility improvement (reduction of delta deciviews) achieved by the control option. Therefore, the incremental cost effectiveness can be expressed with the following formula:

Incremental Cost Effectiveness (dollars per incremental reduction in delta deciviews) =

(Total annualized costs of control option N) - (Total annualized costs of control option N-1) ÷

(Control option N's delta deciview improvement relative to base case - Control option N-1's delta deciview improvement relative to base case).

The basic BART determination metric is therefore "dollars per deciview improvement", for which results are provided in Section 5. Results for the more traditional dollars per ton removed are also provided.

3.0 Description of Emission Control Alternatives

3.1 NO_x Emission Controls

The combined combustion techniques available to control NO_x from White Bluff Units 1 and 2 to the presumptive limit of 0.15 lb/MMBtu with the currently-used sub-bituminous coal are listed in Tables 3-1 and 3-2. The tables also include capital and operational and maintenance costs as well as short-term emission rates for NO_x. The base case represents the present boiler, with a base emission rate of 0.468 and 0.463 lb/MMBtu, respectively. Cost information for the NO_x control options is further documented in Appendix A, Table A-2. The planned capacity factor of these units for the future is about 85%.

The NO_x control options, which would be implemented in combined fashion, are discussed below.

- Boiler tuning does not require any add-on equipment, but is simply the result of boiler adjustments that minimize the formation of NO_x. Any prudent NO_x reduction measures should begin with boiler tuning to verify and optimize current boiler operating parameters. The fine-tuning of oxygen and fuel content in the combustion zone can improve efficiency and reduce NO_x emissions. Beyond simple tuning, systems can be installed to automatically monitor and trim oxygen and fuels for peak performance.
- Overfire Air (OFA) – Furnace overfire air (OFA) technology involves the introduction of combustion air that is separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of N_2 rather than NO_x. In this process, “primary” air (70-90%) is mixed with the fuel to produce a relatively low-temperature, oxygen-deficient, fuel-rich zone in which moderate amounts of fuel NO_x are formed. A “secondary” combustion air supply (10-30%) is injected above the combustion zone through a special wind-box with air ports and/or nozzles, mounted above the burners. Combustion is completed in this zone. The relatively low-temperature secondary-stage limits the production of thermal NO_x, although the location of the injection ports and mixing of overfire air are critical to maintain efficient combustion.
- Low NO_x burners (LNB) are designed to control fuel and air mixing at each burner in order to create larger and more branched flames. This internal combustion staging reduces peak flame temperature and results in less NO_x formation. In addition, the improved flame structure also reduces the amount of oxygen available in the hottest part of the flame, thus improving burner efficiency.

The resulting NO_x emission rate for the presumptive BART control option is slightly below 0.15 lb/MMBtu, the presumptive limit. This emission level has been previously demonstrated on pulverized coal boilers burning sub-bituminous coal.

Table 3-1 NO$_x$ Control Options for White Bluff Unit 1

		Costs per ton removed	% removal	Resulting lb/MMBtu
Case 1	Base Case	$0	0%	0.468
Case 2	Tuning/OFA/LNB	$463	69.0%	0.145

Table 3-2 NO$_x$ Control Options for White Bluff Unit 2

		Costs per ton removed	% removal	Resulting lb/MMBtu
Case 1	Base Case	$0	0%	0.463
Case 2	Tuning/OFA/LNB	$437	69.0%	0.143

Key to terminology:

Tuning	Combustion Tuning
OFA	Overfire Air
LNB	Low NO$_x$ Burners

3.2 SO_2 Emission Control

The BART rule indicates that there are two main options for SO_2 control for coal-fired plants subject to presumptive controls: 0.15 lb/MMBtu using either limestone-forced oxidation ("wet" scrubbing) or lime spray dryers and fabric filters ("dry" scrubbing). Cost information for the SO_2 control options is further documented in Appendix A, Table A-1. These two options have features that are discussed below.

In a wet scrubber, a liquid sorbent is sprayed into the flue gas in an absorber vessel. The SO_2 comes into direct contact with the sorbent and is dissolved into the liquid. A wet slurry waste or by-product, such as gypsum, is produced that may be sold. Most wet FGD systems use alkaline slurries of limestone or slaked lime as sorbents.

Wet scrubbing can achieve high levels of multi-pollutant control, including acid gases, SO_2, fine particulates and heavy metals (i.e., mercury) from utility boilers. They generally have relatively modest space requirements, and are able to process high temperature, high acidity, and high humidity flue gas streams. The control efficiency achievable by wet scrubbers in retrofit cases is up to 95% control, with up to 50% control of sulfuric acid mist emissions.

Wet scrubbers do, however, have certain drawbacks in the use of water and generation of by-product. Also, flue gas temperatures are reduced by wet scrubbers, a fact that is accounted for in the dispersion modeling.

In a lime spray dryer ("dry" scrubbing), a slurry of lime reagent is atomized into the hot flue gas to absorb the pollutants. The resulting dry material, including fly ash, is collected in a downstream particulate control device, in this case a fabric filter. Oxidation of the mixture results in a gypsum by-product that can be sold. The requirement for a fabric filter system substantially increases the retrofit cost for this SO_2 control option.

Dry scrubbers do not have as high an SO_2 removal rate as wet scrubbers, up to 92% control vs. 95% control for wet scrubbers. Some benefits for dry scrubbers include less water use and reduced by-product handling, with up to 90% control of sulfuric acid mist emissions. There is also a flue gas temperature drop with dry scrubbers, although not as much as with wet scrubber systems.

The two options available to control SO_2 from White Bluff Units 1 and 2 to the presumptive limit of 0.15 lb/MMBtu are listed in Table 3-3. CALPUFF model input parameters are provided separately in the computer modeling archive and have been also provided separately to ADEQ.

Table 3-3 SO_2 Control Options for White Bluff Units 1 and 2

		Costs per ton removed**	**% removal**	**Resulting* lb/MMBtu**
Case 1	Limestone forced oxidation (wet scrubbing)	$620	95%	0.150
Case 2	Lime spray dryer (dry scrubbing)	$1,280	92%	0.150

*depends upon future coal sulfur content; 0.15 lb/MMBtu is the presumptive limit

** These costs assume excess allowances are sold; if a viable market does not exist, then costs will be higher.

3.3 PM_{10} Emission Control

The use of electrostatic precipitators effectively limits the PM_{10} emissions from White Bluff Units 1 and 2. No further BART analysis is required for PM_{10}. The emission rate to be used in the modeling corresponds to the peak daily emission rate in 2001-2003: 217.4 and 234.7 lb/hr for Units 1 and 2, respectively. These emissions have been speciated into filterable (coarse and fine inorganic matter and elemental carbon), and condensable PM_{10} using National Park Service-provided guidance. The details of the speciation are provided separately in the computer modeling archive.

4.0 Selection of Control Scenarios for Modeling

Visibility impacts have been evaluated with modeling based on maximum 24-hour emission rates for SO_2, NO_x, and PM_{10} for each option for the criteria pollutants. For evaluating visibility improvement as a result of installing the BART options, the first step is to identify the level of improvement in the 24-hour maximum emissions, from the baseline to the proposed new limits. Table 4-1 lists each control option, as applied to each unit for the separate NO_x controls. The applicable emission rate and percent emissions reduction from the 24-hour baseline emission rate used for modeling are also listed.

Table 4-1 SO_2 and NO_x Emission Rates for Visibility Evaluation for Each Considered Option

Units	Control Option	Baseline Peak 24-hour SO_2 and NO_x Emissions (lb/hour)	Reduction from Baseline Peak 24-hour Rate for SO_2* and NO_x(%)	Future Peak 24-hour Emission Rate for SO_2 and NO_x (lb/hour)
1 and 2	1) Base case	SO_2: 7763.3, 7825.0 NO_x:4371.7, 4730.8	0%	--
1 and 2	2) NO_x: tune/OFA/LNB; SO_2: wet scrubbing		SO_2: up to 95% NO_x: about 69%	SO_2: 1400.8, 1533.2 NO_x:1353.1, 1464.2
1 and 2	3) NO_x: tune/OFA/LNB; SO_2: dry scrubbing		SO_2: up to 92% NO_x: about 69%	SO_2: 1400.8, 1533.2 NO_x:1353.1, 1464.2

*depends upon future coal sulfur content; 0.15 lb/MMBtu is the presumptive limit

The baseline modeling visibility impact was determined for each modeling year (2001-2003); the refined modeling database is described in a separate modeling protocol submitted to ADEQ in October 2006. The modeling results are discussed in the next section.

5.0 Selection of the Best Alternative for BART Control

For the control options listed in Section 4, the results of the CALPUFF modeling in terms of the delta deciviews for the 98th percentile (8th highest day) as modeled for three meteorological years (2001-2003) and for the three Class I areas are presented in Table 5-1 for the controlling year (2003) and Class I area (Caney Creek). Results of modeling for other years and Class I areas are provided separately in the computer modeling archive.

The table also includes the annualized control cost that is the product of the $/ton removed and the number of tons of SO_2 and NO_x removed by each control strategy (assuming an 85% utilization factor), as well as an incremental computation of each control option's visibility improvement effectiveness and cost. The results of the modeling that show the visibility improvement as a function of the cost for each control option are also plotted for ease of interpretation in Figure 5-1.

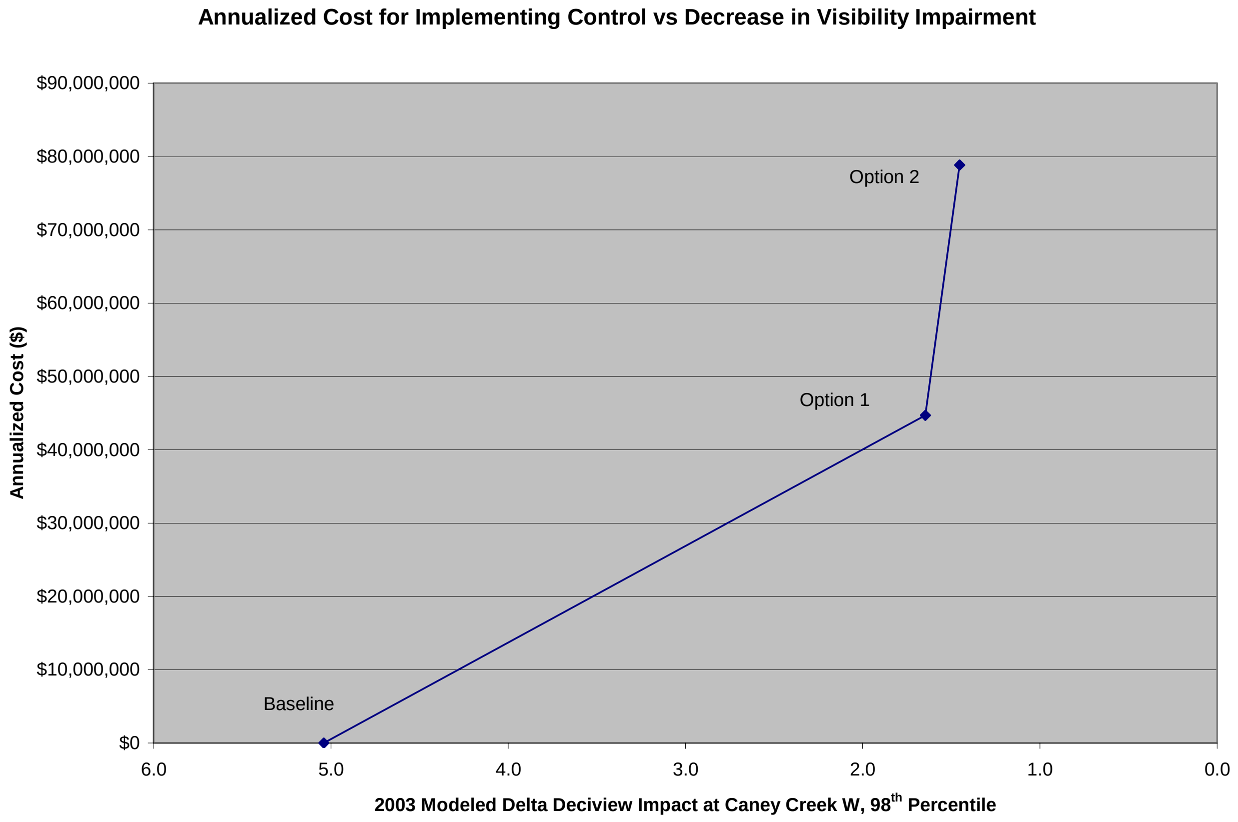
An estimated annualized cost of $44,696,851for the control scenario option 1 was computed by adding the cost of Tune/OFA/LNB to control NO_x emissions and wet scrubbing to control SO_2 emissions from both units. An estimated annualized cost of $78,856,392 for the control scenario option 2 was computed by adding the cost of Tune/OFA/LNB to control NO_x emissions and dry scrubbing to control SO_2 emissions from both units. Detailed cost information for the NO_x and SO_2 control options is further documented in Appendix A, Table A-1 through Table A-3.

Table 5-1 Tabulation of Visibility Improvement and Annual Costs for Each Control Option

Control Scenario Options	Description	Delta deciviews from Natural Conditions (98th Percentile Day)	Annualized Cost ($/Year)	Incremental Cost from Previous Control Scenario ($/Year)	Incremental Cost Effectiveness ($/deciview Relative to the Previous Control Scenario)
Baseline	Base case	5.040	--	--	--
1	NO_x: Tune, OFA, LNB SO_2: wet scrubbing	1.646	$44,696,851	$44,696,851	$13,169,373
2	NO_x: Tune, OFA, LNB SO_2: dry scrubbing	1.453	$78,856,392	$34,159,541	$176,992,442

The results of the BART analysis showing the incremental cost effectiveness of the BART options are provided in Table 5-1 are plotted graphically in Figure 5-1 for the worst-case modeled year (2003) and Class I area (Caney Creek). Figure 5-1 shows that the visibility benefits for both BART options are nearly the same (with dry scrubbing being slightly better due to a hotter plume and lower H_2SO_4 emissions for the same lb/MMBtu controlled SO_2 emissions), while the annualized costs for dry scrubbing plus NO_x controls are nearly twice that of wet scrubbing plus NO_x controls. Therefore, BART is selected as wet scrubbing for SO_2 and the boiler tuning, OFA, and LNB controls for NO_x.

Figure 5-1 Plot of Visibility Improvement vs. Annualized Control Cost for BART Options



Appendix A

Cost and Emission Estimates for SO_2 and NO_x Control Options

Note: The information in this appendix is confidential business-sensitive data that is being provided solely for agency review of this BART determination submittal. In accordance with the BART rule discussion of the need for the review process to preserve the confidentiality of sensitive business information, Entergy requests that the information in this appendix not be disclosed to the public.

Table A-1 White Bluff Unit 1&2 SO_2 Control Options and Cost

White Bluff Unit 1 SO_2 Control Options

SO_2 Control	% Removal	SO_2 lb/MMBtu	SO_2 lb/hr	H_2SO_4 lb/hr	TPY @ 85% util	TPY Removed	$/ton Removed (1)	Annualized Costs ($)
Base case	0%	0.83	7763.3	77.6	28902.8	0.0	0	$0.00
Limestone forced oxidation	95.0%	0.15	1400.8	140.1	5215.1	27457.6	620	$17,023,734.94
Lime Spray Dryer+FF	92.0%	0.15	1400.8	17.5	5215.1	26590.6	1280	$34,035,908.78

White Bluff Unit 2 SO_2 Control Options

SO_2 Control	% Removal	SO_2 lb/MMBtu	SO_2 lb/hr	H_2SO_4 lb/hr	TPY @ 85% util	TPY Removed	$/ton Removed (1)	Annualized Costs ($)
Base case	0%	0.77	7825.0	78.2	29132.5	0.0	0	$0.00
Limestone forced oxidation	95.0%	0.15	1533.2	153.3	5708.1	27675.8	620	$17,159,020.50
Lime Spray Dryer+FF	92.0%	0.15	1533.2	19.2	5708.1	26801.9	1280	$34,306,388.01

(1) Washington Group Inc. Project No. 27447-065 - White Bluff Units 1&2 FGD Cost Estimate Update, October 2006.

Table A-2 White Bluff Unit 1&2 NOx Control Options and Cost

White Bluff Unit 1 NO_x Control Options (1)

NOx Control	% Removal	lb/MMBtu	lb/hr	g/sec	TPY @ 85% util	TPY Removed	Average cost/ton	Annual Cost	Incr. tons Removed	Incr. Cost/ton	Incr. Cost
Base case	0%	0.468	4371.7	550.8	16275.7	0.0	$0	$0	0	$0	$0
Tune	37.0%	0.295	2754.1	347.0	10253.7	6022.0	$21	$128,088	6022.0	$21	$128,088
Tune/OFA	53.6%	0.217	2027.0	255.4	7546.7	8729.0	$101	$882,767	2707.0	$279	$754,678
Tune/OFA/LNB	69.0%	0.145	1353.1	170.5	5037.4	11238.3	$463	$5,201,532	2509.3	$1,721	$4,318,766

White Bluff Unit 2 NO_x Control Options (1)

NOx Control	% Removal	Lb/MMBtu	lb/hr	g/sec	TPY @ 85% util	TPY Removed	Average cost/ton	Annual Cost	Incr. tons Removed	Incr. Cost/ton	Incr. Cost
Base case	0%	0.463	4730.8	596.1	17612.9	0.0	$0	0	0	$0	$0
Tune	37.0%	0.292	2980.4	375.5	11096.1	6516.8	$20	$131,509	6516.8	$20	$131,509
Tune/OFA	53.6%	0.215	2193.6	276.4	8166.7	9446.2	$96	$906,741	2929.4	$265	$775,232
Tune/OFA/LNB	69.0%	0.143	1464.2	184.5	5451.3	12161.6	$437	$5,312,563	2715.4	$1,623	$4,405,823

(1) Prepared by Entergy using Northbridge Entergy NO_x Model with BART, 10-09-2006

Table A-3 Summary of White Bluff Unit 1&2 NO_x and SO_2 Control Options and Total Annual Cost

Control Scenario Option	NO_x and SO_2 Controls	Total Annual Cost		
		Unit 1	Unit 2	Unit 1+2
Baseline	No Controls	$0.0	$0.0	$0.0
Option 1	Tune/OFA/LNB	$5,201,532	$5,312,563	$44,696,851
	Limestone forced oxidation	$17,023,735	$17,159,020	
Option 2	Tune/OFA/LNB	$5,201,532	$5,312,563	$78,856,392
	Lime Spray Dryer+FF	$34,035,909	$34,306,388	

Calculation Method Used In BART Determination

Standard engineering economic analysis is used to convert all costs to equivalent levelized annual costs so that the pollution control cost effectiveness (in dollars per ton of pollutant controlled) may be calculated for comparison with other control options.

Definition of Levelized Annual Cost - For reference, levelized costs are related directly to the present value of a scenario, and they are equivalent to the uniform annual cost that has the same present value as the actual annual costs over the life of the unit. Levelized costs are essentially the weighted average of the actual annual costs. Annual costs will increase each year due to escalation of the costs of specific commodities and due to the general inflation rate. Economic factors are applied to the three components of the total levelized cost:

- Fixed O&M Costs - operating and administrative labor and maintenance costs
- Variable - consumable costs that vary with plant operating load, such as auxiliary power, chemicals, water, solid waste disposal, etc.
- Fixed Carrying Charges - the charges associated with financing the capital investment.

When these components are added together, they provide the total levelized cost for each technology option.

Variable and Fixed Operating Cost Levelization – The annual costs for all variable and fixed operating cost components are calculated based on the system material balance and system operating assumptions. Operating labor cost is based on the number of personnel that need to be added to the plant staff to operate the new equipment and subsystems. Maintenance costs are calculated as a percentage of the total installed cost of the equipment, including both labor and materials costs. These first-year annual costs are then multiplied by a “levelization factor” to calculate the levelized annual cost contribution of the variable costs. The levelization factor is calculated using the following equation:

$$\left[\frac{(1 + i)}{(i - e)}\right] \times \left[\frac{(1 + i)^n - (1 + e)^n}{(1 + i)^n}\right]$$

where i = discount rate
e = annual escalation rate
n = number years of plant operating life

Fixed Capital Charges – These costs represent the carrying charge associated with financing the Total Capital Requirement (TCR) for the emissions control system retrofit. The TCR cost estimates include both direct costs (equipment purchase costs, sales taxes, freight, installation costs, foundations, supports, field erection, electrical, piping, insulation, and painting) and indirect costs (engineering, construction, contractor fees, start-up, performance tests, contingencies, and interest during construction).

Total Capital Requirement (TCI) = Direct Capital Cost + Indirect Capital Cost

The fixed charge rate is the sum of the return on equity, income tax (both current and deferred), book depreciation, property tax, and insurance. It is equivalent to the amount of revenue per dollar of Total Capital Requirement that must be collected from customers in order to pay the carrying charges on that investment.

The Fixed Charge Rate is multiplied times the TCR to obtain a dollar amount, typically a levelized annual cost over a specified operating life of the new equipment. This factor is also called the carrying charge rate.

Levelized Annual Capital Recovery (ACR) = FCR x TCR

The cost effectiveness of a control technology is calculated by dividing the total annualized costs of the control technology by the total tons of pollutant emissions removed by the control equipment per year.

Levelized Control Cost = $\dfrac{\text{Levelized ACR + Levelized Fixed and Variable Annual Cost}}{\text{Annual Tons of } SO_2 \text{ Removed}}$

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