Oklahoma Department of Environmental Quality
Air Quality Division

Revised BART Determination **June 13, 2013**

COMPANY:	**AEP-Public Service Company of Oklahoma**
FACILITY:	**Northeastern Power Plant**
FACILITY LOCATION:	**Rogers County, Oklahoma**
TYPE OF OPERATION:	**Two 490 MW Coal-Fired Steam Electric Generating Units (Units 3 & 4)**
REVIEWER:	**Lee Warden, Engineering Manager**

I. PURPOSE

The U.S. Environmental Protection Agency (EPA) published the final decision to partially approve and partially disapprove the Oklahoma Regional Haze (RH) State Implementation Plan (SIP) and simultaneously issue a Federal Implementation Plan (FIP) on December 28, 2011. *See* 76 Fed.Reg. 81727 (Dec. 28, 2011). The FIP became effective on January 27, 2012. The FIP established Dry Flue Gas Desulfurization with a Spray Dry Absorber (DFGD/SDA) as the Best Available Retrofit Technology (BART) for SO_2 emissions control from American Electric Power (AEP) - Public Service Company of Oklahoma (PSO or AEP/PSO) Northeastern Units 3 and 4. The DEQ-determined controls for NO_X and PM_{10}, low NO_X burners with over-fire air (LNB w/ OFA) and continued use of existing electrostatic precipitators (ESP) were approved. The decision also approved DEQ's BART determination for the AEP/PSO Northeastern Unit 2, a 495 MW gas-fired unit. Subsequent to publishing the final FIP, AEP/PSO, DEQ, EPA, and the U.S. Department of Justice entered discussions on alternatives to DFGD/SDA that would provide the necessary visibility improvements. Notice of the proposed settlement agreement was published in the Federal Register on November 14, 2012 (77 Fed.Reg. 67814). The final settlement agreement, partially summarized below, is the result of these discussions. On November 20, 2012, AEP/PSO submitted to DEQ the Supplemental BART Determination Information under terms of the settlement agreement.

II. SUPPLEMENTAL BART DETERMINATION INFORMATION

The Supplemental BART Determination Information lays out a plan for AEP/PSO's revised proposal for BART, as part of a long-term multi-media, multi-pollutant plan, which entails shutting down one of the two units by April 16, 2016, and installing and operating a dry sorbent injection system (DSI) on the other unit from April 16, 2016 to December 31, 2026, at which point AEP/PSO would shut down the remaining unit.

In compliance with the 2010 BART determination and in anticipation of federal requirements, AEP/PSO completed installation of new LNB w/ OFA. The Supplemental BART Determination Information acknowledges these NO_X reductions and proposes limits on NO_X and SO_2 emissions prior to the SIP/FIP deadlines for installation and operation of BART controls. The limits assume full load operation of both units until April 16, 2016 and continued use of low sulfur coal. Table 1 identifies the proposed limits and timelines as reflected in the Supplemental BART Determination Information for the early NO_X and SO_2 emission reductions.

Table 1: Early NO_X and SO_2 Reductions

Early Reductions		
By December 31, 2013	**Unit 3**	**Unit 4**
NO_X Control	LNB w Separated OFA	LNB w Separated OFA
Emission Rate (lb/mmBtu)	0.23 lb/mmBtu (30-day rolling average)	0.23 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	1,098 lb/hr (30-day rolling average)	1,098 lb/hr (30-day rolling average)
Emission Rate TPY	9,620 TPY (12-month rolling)	
By January 31, 2014	**Unit3**	**Unit 4**
SO_2 Control	Low Sulfur Coal	Low Sulfur Coal
Emission Rate (lb/mmBtu)	0.65 lb/mmBtu (30-day rolling average)	0.65 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	3,104 lb/hr (30-day rolling average)	3,104 lb/hr (30-day rolling average)
By December 31, 2014	**Unit3**	**Unit 4**
SO_2 Control	Low Sulfur Coal	Low Sulfur Coal
Emission Rate (lb/mmBtu)	0.60 lb/mmBtu (12-month rolling average)	0.60 lb/mmBtu (12-month rolling average)
Emission Rate (TPY)	25,097 TPY	

The Supplemental BART Determination Information proposes a shutdown date for both units, and controls based on the remaining useful life of each unit. The FIP required installation of DFGD/SDA on both units within 5 years of its effective date, January 27, 2012. This would require controls to be installed and operational by January of 2017.

The Supplemental BART Determination Information provides that AEP/PSO will shut down one unit by April 16, 2016 prior to the FIP-required control date. The Supplemental BART Determination Information also proposes that AEP/PSO will shut down the second unit by December 31, 2026, and relies upon the remaining useful life of the unit to justify installation of DSI for SO_2 emissions control as BART in lieu of the more costly DFGD/SDA specified in the FIP. To further reduce emissions, the Supplemental BART Determination Information proposes capacity utilization reductions over the remaining life of the unit, beginning in the year 2021.

The Supplemental BART Determination Information provides for the possibility of an earlier shutdown of the second unit, contingent on an analysis of projected costs from natural gas or renewable resources conducted in calendar year 2021. However, the evaluations of cost and visibility improvement relied upon in this revised BART Determination do not take into account the possibility of an earlier shutdown.

Due to increased particle loading, the installation of DSI will necessitate the addition of a fabric filter baghouse. The BART determination in the 2010 SIP required no further controls and a continued reliance on the electrostatic precipitator (ESP). The proposal for DSI, while forcing further PM controls, does not open the prior PM BART determination for additional review.

Tables 2 and 3 identify the limits and timeline for the proposed BART control for SO_2, the timeline for early compliance with the approved NO_X BART control, and the proposed decreases in capacity utilization through the useful life of the remaining unit.

Table 2: Revised SO_2 BART

BART Control with Unit Shutdown	
By April 16, 2016	**Remaining Unit**
SO_2 Control	**Dry Sorbent Injection with Activated Carbon Injection**
Emission Rate (lb/mmBtu)	0.4 lb/mmBtu (30-day rolling average)
Emission Rate lb/hr	1,910 lb/hr (30-day rolling average)
Emission Rate TPY	8,366 TPY
NOx Control	**LNB w/ Separated OFA (Further Control System Tuning)**
Emission Rate (lb/mmBtu)	0.15 lb/mmBtu (30-day rolling average)
Emission Rate (lb/hr)	716 lb/hr (30-day rolling average)
Emission Rate TPY	3,137 TPY

Table 3: Further Reductions

Further Reasonable Progress over Remaining Unit Life		
	NO_X	**SO_2**
January 1, 2021 70% Utilization	2,196 TPY	5,856 TPY
January 1, 2023 60% Utilization	1,882 TPY	5,019 TPY
January 1, 2025 50% Utilization	1,569 TPY	4,183 TPY
December 31, 2026	Unit Shutdown	

III. BART-ELIGIBLE AND BART-SUBJECT DETERMINATION

BART is required for any BART-eligible source that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I Area. DEQ has determined that an individual source will be considered to "contribute to visibility impairment" if emissions from the source result in a change in visibility, measured as a change in deciviews (Δ-dv), that is greater than or equal to 0.5 dv in a Class I area (OAC 252:100-8-73). Visibility impact modeling conducted by AEP/PSO as part of the initial BART review determined that the maximum predicted visibility impacts from Northeastern Units 3 and 4 exceeded the 0.5 Δ-dv threshold at the Wichita Mountains, Caney Creek, Upper Buffalo, and Hercules Glade Class I Areas. Therefore, Northeastern Units 3 and 4 were determined to be BART applicable sources, subject to the BART determination requirements.

IV. BART ANALYSIS STEPS

Guidelines for making BART determinations are included in Appendix Y of 40 C.F.R. Part 51 (Guidelines for BART Determinations under the Regional Haze Rule). States are required to use the Appendix Y guidelines to make BART determinations for fossil-fuel-fired generating plants having a total generating capacity in excess of 750 MW. The BART determination process described in Appendix Y includes the following steps:

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.
Step 5. Evaluate Visibility Impacts.

In the final Regional Haze Rule, EPA established presumptive BART emission limits for SO_2 and NO_X for certain electric generating units (EGUs) based on fuel type, unit size, cost effectiveness, and the presence or absence of pre-existing controls. The presumptive limits apply to EGUs at power plants with a total generating capacity in excess of 750 MW. For these sources, EPA established presumptive emission limits for coal-fired EGUs greater than 200 MW in size. The presumptive levels are intended to reflect highly cost-effective technologies as well as provide enough flexibility to States to consider source-specific characteristics when evaluating BART. The BART SO_2 presumptive emission limit for coal-fired EGUs greater than 200 MW in size without existing SO_2 control is either 95% SO_2 removal, or an emission rate of 0.15 lb/mmBtu, unless a State determines that an alternative control level is justified based on a careful consideration of the statutory factors. For NO_X, EPA established a set of BART presumptive emission limits for coal-fired EGUs greater than 200 MW in size based upon boiler size and coal type. The BART NO_X presumptive emission limit applicable to Northeastern Units 3 and 4 (tangentially fired boilers firing subbituminous coal) is 0.15 lb/mmBtu and was approved in the final SIP/FIP action. Appendix Y does not establish a BART presumptive emission limit for PM.

Potentially available control options designed to remove SO_2 from coal-fired combustion gases were identified and reviewed in the original BART Application Analysis dated January 16, 2010 and EPA's FIP evaluation. EPA concluded in the FIP that DFGD/SDA satisfied the BART review requirements; therefore, no further analysis of Wet Flue Gas Desulfurization is necessary. Likewise, those technologies previously deemed technically infeasible are not under review again.

Table 4: List of Potential Control Options

Control Technology
Dry Sorbent Injection
Dry Flue Gas Desulfurization-Spray Dryer Absorber

Post-Combustion Flue Gas Desulfurization:

Dry Flue Gas Desulfurization

DFGD is a dry scrubbing system that has been designed to remove SO_2 from coal-fired combustion gases. Dry scrubbing involves the introduction of dry or hydrated lime slurry into a reaction tower where it reacts with SO_2 in the flue gas to form calcium sulfite solids. Unlike wet FGD systems that produce a slurry byproduct that is collected separately from the fly ash, DFGD systems produce a dry byproduct that must be removed with the fly ash in the particulate control equipment. Therefore, DFGD systems must be located upstream of the particulate control device to remove the reaction products and excess reactant material.

Spray Dryer Absorber

SDA systems have been used in large coal-fired utility applications. SDA systems have demonstrated the ability to effectively reduce uncontrolled SO_2 emissions from coal units. The typical spray dryer absorber uses a slurry of lime and water injected into the tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry to produce a relatively dry by-product. SDA control systems are a technically feasible and commercially available retrofit technology for Northeastern Units 3 and 4. Based on the fuel characteristics and allowing a reasonable margin to account for normal operating conditions (e.g., load changes, changes in fuel characteristics, reactant purity, atomizer change outs, and minor equipment upsets), it is concluded that FGD designed as SDA could achieve a controlled SO_2 emission rate of 0.15 lb/mmBtu (30-day average) or less on an on-going long-term basis.

Dry Sorbent Injection

DSI involves the injection of a sorbent, or reagent (e.g., sodium bicarbonate) into the exhaust gas stream upstream of a particulate control device. The SO_2 reacts with the reagent and the resulting particle is collected in the particulate control system. The process was developed as a lower cost FGD option because the existing ductwork acts as the absorber vessel, removing the need to install a new, separate absorber vessel. Depending on the residence time, gas stream temperature, and limitations of the particulate control device, sorbent injection control efficiency can range between 40 and 60 percent.[1]

Table 5: Technically Feasible SO_2 Control Technologies - Northeastern Power Station

Control Technology	Northeastern Unit 3 Approximate SO_2 Emission Rate (lb/mmBtu)	Northeastern Unit 4 Approximate SO_2 Emission Rate (lb/mmBtu)
Dry FGD- Spray Dryer Absorber[1]	0.06	0.06
Dry Sorbent Injection	0.4	-
Baseline	0.9	0.9

[1]The DFGD/SDA emission rate listed is reflective of the FIP control determination and presumably achievable.

[1] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers ,Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005.

AEP/PSO evaluated the economic, environmental, and energy impacts associated with the two proposed control options. In general, the cost estimating methodology followed guidance provided in the EPA Air Pollution Control Cost Manual, Sixth Edition ("the Manual"). The capital and operating costs of the DSI control option, i.e., the proposed scenario, were estimated based on the Manual except as listed below.

- *Purchased Equipment Costs*, *Site Preparation Costs*, and *Building Costs* were based on an approximate six-month, site-specific, feasibility and conceptual engineering and design effort that resulted in a Class 4 AACE category budgetary estimate.
- *Operating Labor Costs*, *Maintenance Labor Costs*, and *Other Direct Operating Costs* (e.g., for sorbent usage, electricity, and bag and cage replacement) were based on an evaluation of annual operating and maintenance cost project impact as part of the above-mentioned feasibility and conceptual design effort.
- The *Indirect Operating Costs* of *Overhead*, *Property Tax*, and *Insurance* were based on the same calculation methodologies presented in EPA's Technical Support Document (TSD) published with the RH FIP. These methodologies deviate from the Manual but were used for the purpose of consistency with the FIP.

The capital recovery factor used to estimate the annual cost of control of the DFGD/SDA option was based on a 7% interest rate and a control life of 30 years. Annual operating costs and annual emission reductions were calculated assuming a capacity factor of 85%.

The capital costs for the DSI option were annualized over a 10-year period and then added to the annual operating costs to obtain the total annualized costs. An equipment life of 10 years was used because the controls will only be in operation for 10 years, from 2016 to 2026, before the unit is shut down. Further, the capacity factor will decrease over the 10 year period. However, the facility will not be taking a limit on capacity until 2021; therefore, the cost analyses are based on an 85% capacity factor to be consistent with baseline actual capacity usage and with all previous evaluations.

Table 6: Economic Cost for Unit 3 and 4 - Dry FGD w/ Spray Dryer Absorber

Cost	DFGD/SDA
Total Capital Investment ($)	$274,100,000
Total Capital Investment ($/kW)	$280
Capital Recovery Cost ($/Yr)	$22,088,733
Annual O&M Costs ($/Yr)	$15,040,231
Total Annual Cost ($)	$44,969,595

Table 7: Economic Cost for Unit 3 – DSI

Cost	DSI
Total Capital Investment ($)	$111,332,077
Total Capital Investment ($/kW)	$227
Capital Recovery Cost ($/Yr)	$15,851,183
Annual O&M Costs ($/Yr)	$5,972,469
Total Annual Cost ($)	$25,008,306

Table 8: Environmental Costs for Unit 3 and 4

	Baseline	DSI	DFGD/SDA
SO_2 Emission Rate (lb/mmBtu)	0.9	0.4	0.06
Annual SO_2 Emission (TPY)[1]	31,999	7,111	2,880
Annual SO_2 Reduction (TPY)	--	24,888	29,119
Total Annual Cost ($)		$25,008,306	$44,969,595
Cost per Ton of Reduction		$1,005/ton	$1,544/ton

[1]Baseline annual emissions were averaged based on annual emissions from 2004 - 2006. Projected annual emissions for DFGD/SDA option were calculated based on the controlled SO_2 emissions rate (a 91% reduction from the baseline). Projected annual emissions for DSI option were calculated based on the controlled SO_2 emissions rate, full load heat input of 4,775 mmBtu/hr, and assuming a 85% capacity factor.

The fifth step for a BART determination analysis, as required by 40 C.F.R. Part 51, Appendix Y, is to evaluate the degree of Class I area visibility improvement that would result from the installation of the various options for control technology. This factor was evaluated for the Northeastern Units 3 and 4 by using an EPA-approved dispersion modeling system (CALPUFF) to predict the change in Class I area visibility.

Only those Class I areas most likely to be impacted by the Northeastern Power Plant were modeled, as determined by source/Class I area locations, distances to each Class I area, and considering meteorological and terrain factors. Wichita Mountain Wildlife Refuge, Caney Creek, Upper Buffalo and Hercules Glade are the closest Class I areas to the Northeastern Power Plant. It can be reasonably assumed that areas at greater distances and in directions of less frequent plume transport will experience lower impacts than those predicted for the four modeled areas.

DESCRIPTION OF BART SOURCES AND MODELING APPROACH

In accordance with EPA guidelines in 40 C.F.R. Part 51, Appendix Y Part III, emission estimates used in the modeling analysis to determine visibility impairment impacts should reflect steady-state operating conditions during periods of high capacity utilization. Therefore, modeled emissions (lb/hr) represent the highest 24-hour block emissions reported during the baseline period. Baseline emissions data were provided by AEP/PSO. Baseline emission rates (lb/mmBtu) were calculated by dividing the maximum 24-hr lb/hr emission rate by the maximum heat input to the boiler at that emission rate.

Table 9: Northeastern Power Plant - Modeling Parameters for BART Evaluation

Parameter	Northeastern Unit 3		Northeastern Unit 4	
Plant Configuration	Coal-Fired Boiler		Coal-Fired Boiler	
Firing Configuration	Tangentially-fired		Tangentially-fired	
Gross Output (nominal)	490 MW		490 MW	
Design Input to Boiler	4,775 mmBtu/hr		4,775 mmBtu/hr	
Maximum 24-hour Average Input	5,812 mmBtu/hr		5,594 mmBtu/hr	
Primary Fuel	Sub-bituminous coal		Sub-bituminous coal	
Existing NO_X Controls	1st Generation LNB/OFA		1st Generation LNB/OFA	
Existing PM_{10} Controls	Electrostatic precipitator		Electrostatic precipitator	
Existing SO_2 Controls	Low-sulfur coal		Low-sulfur coal	
Baseline Emissions				
	Unit 3		**Unit 4**	
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	3,116	0.536	2,747	0.491
SO_2	6,126	1.054	5,930	1.06
SIP Approved Emissions (Max 24-hour)				
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	872	0.15	839	0.15
Unit 4 Shut Down/Unit 3 NO_X Controlled, SO_2 Baseline (Max 24-hour)				
	lb/hr	**lb/mmBtu**	**lb/hr**	**lb/mmBtu**
NO_X	872	0.15	-	-
SO_2	6,126	1.054	-	-
Unit 4 Shut Down/Unit 3 NO_X Controlled, SO_2 DSI Control (Max 24-hour)				
NO_X	872	0.15	-	-
SO_2	2,325	0.4	-	-

REFINED MODELING

AEP/PSO was required to conduct a refined BART analysis that included CALPUFF visibility modeling for the facility. The modeling approach followed the modeling conducted in support of the Federal Implementation Plan (FIP) and as described in the protocol submitted to DEQ on October 3, 2012.

CALPUFF System

Predicted visibility impacts from the Northeastern Power Plant were determined using the EPA CALPUFF modeling system, which is the EPA-preferred modeling system for long-range transport.

Table 10: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.8	070623
CALPOST	6.221	080724

Meteorological Data Processing (CALMET)

The existing meteorological dataset has been recently reviewed and approved for use by EPA, and formed the foundation for the analyses conducted in support of the FIP. In order to maintain a consistent basis for comparison with previous studies and with the presumption that a model update would not significantly impact an analysis of the relative change between the baseline and control scenarios, the CALMET processing was not updated as part of these analyses.

CALPUFF Modeling Setup

To allow chemical transformations within CALPUFF using the recommended chemistry mechanism (MESOPUFF II), the model required input of background ozone and ammonia. CALPUFF can use either a single background value representative of an area or hourly ozone data from one or more ozone monitoring stations. Hourly ozone data files were used in the CALPUFF simulation. As provided by the Oklahoma DEQ, hourly ozone data from the Oklahoma City, Glenpool, and Lawton monitors over the 2001-2003 time frames were used. Background concentrations for ammonia were assumed to be temporally and spatially invariant and were set to 3 ppb.

Latitude and longitude coordinates for Class I area discrete receptors were taken from the National Park Service (NPS) Class I Receptors database and converted to the appropriate LCC coordinates.

CALPUFF Inputs- Baseline and Control Options

Table 11: Source Parameters

Parameter	Baseline[1]	
	Coal-Fired Unit 3	Coal-Fired Unit 4
Heat Input (mmBtu/hr)	5,812	5,594
Stack Height (m)	183	183
Stack Diameter (m)	8.23	8.23
Stack Temperature (K)	424	415
Exit Velocity (m/s)	18.97	17.46
Baseline SO_2 Emissions (lb/mmBtu)	1.054	1.060
Dry Sorbent Injection	0.4	-
Baseline NO_X Emissions (lb/mmBtu)	0.536	0.491
LNB/OFA NO_X Emissions (lb/mmBtu)	0.15	-

[1]Baseline emissions data were provided by AEP/PSO. Baseline emission rates (lb/mmBtu) were calculated by dividing the maximum 24-hr lb/hr emission rate by the maximum heat input to the boiler at that emission rate.

Visibility Post-Processing (CALPOST) Setup

The changes in visibility were calculated using Method 8 with the CALPOST post-processor. Method 8 incorporates the use of the new IMPROVE (Interagency Monitoring of Protected Visual Environments) equation for predicting light extinction, as found in the 2010 FLAG (*Federal Land Managers Air Quality Related Values Workgroup*) guidance. EPA's default average annual aerosol concentrations for the U.S. that are included in Table 2-1 of EPA's

Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Program were used to develop natural background estimates for each Class I area.

VISIBILITY POST-PROCESSING RESULTS

Table 12: CALPUFF Visibility Modeling Results for Northeast Units 3 and 4- SO_2 and NO_X

Class I Area	2001 98th Percentile Value (Δdv)	2002 98th Percentile Value (Δdv)	2003 98th Percentile Value (Δdv)	3-Year Average 98th Percentile Value (Δdv)
Baseline				
Wichita Mountains	1.228	1.339	1.937	1.501
Caney Creek	1.927	1.290	1.664	1.627
Upper Buffalo	1.389	0.938	1.180	1.169
Hercules Glade	1.179	0.867	1.291	1.112
Unit 4 Shut Down and DSI on Unit 3 (NO_X Baseline)				
Wichita Mountains	0.417	0.356	0.618	0.464
Caney Creek	0.637	0.439	0.584	0.553
Upper Buffalo	0.534	0.293	0.379	0.402
Hercules Glade	0.408	0.291	0.298	0.332
Unit 4 Shut Down and DSI/LNB/OFA on Unit 3				
Wichita Mountains	0.241	0.271	0.372	0.295
Caney Creek	0.346	0.240	0.297	0.294
Upper Buffalo	0.247	0.172	0.231	0.216
Hercules Glade	0.213	0.170	0.246	0.209

Table 13: CALPUFF Visibility Modeling Results for Northeast Units 3 and 4- SO_2 and NO_X

Class I Area	2001 98th Percentile Value (Δdv)	2002 98th Percentile Value (Δdv)	2003 98th Percentile Value (Δdv)	3-Year Average 98th Percentile Value (Δdv)
EPA FIP – DFGD/SDA Units 3 and 4				
Wichita Mountains	0.187	0.163	0.257	0.202
Caney Creek	0.227	0.196	0.252	0.225
Upper Buffalo	0.238	0.129	0.139	0.169
Hercules Glade	0.197	0.129	0.119	0.148

V. BART DETERMINATION

SO_2

DEQ considered: (1) the costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any pollutant equipment in use or in existence at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility (all five statutory factors) from each proposed control technology, to determine BART for the two coal-fired units at the Northeastern Power Station.

As stated in the November 20, 2012 Supplemental BART Determination Information submitted by AEP/PSO, the company intends to shut down one of the two identical units (preliminarily determined to be Northeastern Unit 4) prior to the expiration of the five year period from the FIP effective date, and to shut down the second unit (preliminarily determined to be Northeastern Unit 3) no later than December 31, 2026. In consideration of the shortened lifespans of the units, continued use of low sulfur coal with a DSI system is determined to be BART for SO_2 control.

In general, BART is considered to be a unit-by-unit evaluation. However, in order to more accurately contrast the environmental benefits of one solution versus another, the contemporaneous emission reductions resulting from the multi-media, multi-pollutant strategy proposed in the Supplemental BART Determination Information (through the BART timeframe) is relied upon in the evaluation of the BART solution and contrasted against the FIP scenario through the same time period.

The cost effectiveness in dollars per ton of SO_2 removed for the proposed strategy is $1,005 per ton, and for the FIP scenario, $1,544 per ton. Given the projected level of emission reductions of 24,888 tons per year versus 29,119 tons per year, respectively, the incremental cost effectiveness to achieve the further reductions of the FIP scenario is $4,718 per ton in the first year and with decreased capacity utilization under the proposed scenario, the incremental cost effectiveness worsens.

A DFGD/SDA solution would provide improvements in visibility slightly above that achieved with a DSI system. However, factoring in the proposed strategy, these incremental reductions in emissions of SO_2 do not result in a perceptible improvement in visibility either on an individual Class I area basis or a cumulative Class I area basis. The FIP scenario would result in trivial visibility improvements of approximately 0.1 dv above that of the proposed strategy over individual Class I areas and an average total improvement of 0.27 dv across the four nearest Class I areas during the time of control implementation. Visibility improvements generally must be 1 dv or greater to be perceptible to the human eye. These improvements would be achieved at a much greater cost. The cost effectiveness for the FIP scenario in terms of visibility improvement across all modeled Class I areas is $9,639,785 per dv versus the cost effectiveness of the proposed scenario, $5,690,172 per dv.

The proposed strategy provides for the shutdown of one unit (assumed to be Northeastern Unit 4), and therefore the removal of NO_X, SO_2, PM, and CO_{2e} emissions from the unit. These reductions will help to address local formation and interstate transport of ozone, and reduce the contribution to greenhouse gases and mercury deposition from electricity generation in Oklahoma. The FIP scenario provides no further improvement in ozone, and would likely assure continued use of coal-fired electricity generation for an additional 20 years beyond the proposed scenario. Additionally, the proposed scenario, while achieving perceptively equivalent visibility improvements at the Class I areas, will not require water usage, and in shutting down Northeastern Unit 4 rather than installing additional controls, energy consumption will be approximately half that of the control solution established by the FIP.

Given the comparable visibility improvement, lower costs, and overall reduced environmental impact, the State has determined that an alternative control level (i.e., to the presumptive emission limits) is justified based on a careful consideration of the statutory factors, and that the proposed control constitutes BART. This determination relies upon an enhanced effectiveness provided through contemporaneous emission reductions from the multi-media, multi-pollutant strategy outlined in the Supplemental BART Determination Information and documented in Table 2. Through incorporation in the First Amended Regional Haze Agreement, this strategy is made enforceable and therefore, eligible for reliance upon in the BART determination.

NO_X

DEQ established the BART NO_X emission limit applicable to Northeastern Units 3 and 4 as 0.15 lb/mmBtu (30-day rolling average) in the 2010 Regional Haze SIP. The control technology and emission limits were approved in the final SIP/FIP action. The original Regional Haze Agreement required installation and operation of the controls within 5 years of SIP approval. The Supplemental BART Determination Information does not reopen the NO_X technology determination, but does require earlier installation and compliance with reduced emission limits prior to the original SIP-imposed deadline. Under the First Amended Regional Haze Agreement, the facility is required to comply with an emission limit of 0.23lb/MMBtu on a 30-day rolling average from December 31, 2013 until April 16, 2016; thereafter, the remaining unit must comply with the BART emission limit of 0.15lb/MMBtu on a 30-day rolling average. This early implementation schedule, by reducing NO_X emissions by 43%, will provide previously unanticipated improvements in visibility as well as reductions in local formation and interstate transport of ozone.

The following table provides a summary of the BART controls and limits.

Table 14: BART Controls and Limits after April 16, 2016

Unit	**NO_X BART Emission Limit**	**BART Technology**
Northeastern Unit 3	0.15 lb/mmBtu (30-day average)	Combustion controls including LNB/OFA
Northeastern Unit 4		Shut down by April 16, 2016
Unit	**SO_2 BART Emission Limit**	**BART Technology**
Northeastern Unit 3	0.40 lb/mmBtu (30-day average)	Dry Sorbent Injection
Northeastern Unit 4		Shut down by April 16, 2016

VI. FURTHER REASONABLE PROGRESS

The Supplemental BART Determination Information also provides for decreased capacity utilization in the remaining coal-fired unit over its shortened lifetime. Under this plan, AEP/PSO will shut down the remaining coal-fired unit by December 31, 2026. The visibility impact from the two BART-eligible units will be zero after 2026. With implementation of the decreased capacity utilization limits and the retirement schedule, DEQ expects the cumulative SO_2 and NO_X emissions from Northeastern Units 3 and 4 to be approximately 36% of the emissions that could be emitted under the FIP scenario.

Table 15: SO_2 and NO_X Emissions with Further Reasonable Progress

	Unit 3 and Unit 4	
	SO_2	NO_X
BART (FIP Scenario) (30yrs from January 2017)	75,292 Tons	188,231 Tons
Amended Regional Haze Agreement from April 16, 2016 – December 31, 2026	69,516 Tons	26,068 Tons

Note that under the FIP scenario, AEP/PSO would be authorized to emit an additional approximately 26,700 tons (not included in the table) of SO_2 in the 8½ months between the deadline in the First Amended Regional Haze Agreement and the January 2017 FIP deadline to begin operating with BART controls.

VII. CONSTRUCTION PERMIT

Prevention of Significant Deterioration (PSD)

Northeastern Power Station is a major source under OAC 252:100-8 Permits for Part 70 Sources. AEP/PSO must comply with the permitting requirements of Subchapter 8 as they apply to the installation of controls determined to meet BART on the schedule outlined in the First Amended Regional Haze Agreement.

The installation of controls determined to meet BART will not change NSPS or NESHAP/MACT applicability for the gas-fired units at the Northeastern Power Station.

VIII. OPERATING PERMIT

The Northeastern Power Station is a major source under OAC 252:100-8 and must submit an application to modify their existing Title V permit to incorporate the requirements to install controls determined to meet BART on the schedule outlined in the First Amended Regional Haze Agreement.

AEP
PUBLIC SERVICE
COMPANY OF
OKLAHOMA
A unit of American Electric Power

Public Service Company
of Oklahoma
1601 Northwest Expressway, Suite 1400
Oklahoma City, OK 73118
PSOklahoma.com

November 19, 2012

Eddie Terrell, Air Quality Division Director
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, OK 73101-1677

Re: Revised Regional Haze State Implementation Plan Requirements
Public Service Company of Oklahoma
Northeastern Station Units 3 and 4

Dear Mr. Terrell:

In accordance with Paragraph 2 of the Settlement Agreement executed by Public Service Company of Oklahoma (PSO), the Secretary of the Environment, the Oklahoma Department of Environmental Quality (ODEQ) and Sierra Club, which was issued for public comment on November 14, 2012, 77 *Fed. Reg.* 67,814, PSO herewith submits the Supplemental BART Determination Information to support revised Best Available Retrofit Technology (BART) determinations for Northeastern Station Units 3 and 4. The Supplemental BART Determination Information analyzes the cost-effectiveness and visibility improvements associated with the activities outlined in the Settlement Agreement, which include retiring Northeastern Unit 4, and installing dry sorbent injection, a fabric filter baghouse, and other controls at Northeastern Unit 3 by April 16, 2016, and taking other actions consistent with the terms of the Settlement Agreement.

It is anticipated that following the close of the public comment period, the U.S. Environmental Protection Agency (EPA) will execute the Settlement Agreement, which establishes a schedule for the proposal, adoption, and approval of a revision to the Oklahoma State Implementation Plan (SIP) to incorporate this BART determination. PSO appreciates ODEQ's commitment to promptly review the enclosed submittal, and will promptly respond to any requests for clarification or additional information.

Please contact me if any additional information is required, or if you would like to schedule a meeting to review the submittal and its supporting information.

Very truly yours,

Howard Ground

Howard Ground
Manager State Governmental & Environmental Affairs

SUPPLEMENTAL BART DETERMINATION INFORMATION

AMERICAN ELECTRIC POWER ■ NORTHEASTERN POWER PLANT

Prepared By:

TRINITY CONSULTANTS, INC.

120 East Sheridan, Suite 205
Oklahoma City, OK 73104
(405) 228-3292

9777 Ridge Drive, Suite 380
Lenexa, KS 66219
(913) 894-4500

AMERICAN ELECTRIC POWER SERVICE CORPORATION

PO Box 660164
Dallas, Texas 72566
(214) 777-1113

For :

AEP'S PUBLIC SERVICE COMPANY OF OKLAHOMA (PSO)
NORTHEASTERN STATION GENERATING PLANT

November 9, 2012

Relevant Previous Submittals:

March 30, 2007
May 30, 2008
August 2008

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1. INTRODUCTION

American Electric Power / Public Service Company of Oklahoma (AEP/PSO) operates the Northeastern Power Station and is submitting supplemental information for consideration by the Oklahoma Department of Environmental Quality (ODEQ) and the U.S. Environmental Protection Agency (EPA) in the determination of Best Available Retrofit Technology (BART) for Northeastern's Unit 3 and Unit 4. Previous analyses and other BART-related information were submitted by AEP/PSO on:

▲ March 30, 2007
▲ May 30, 2008
▲ August 2008

The supplemental information provided in this report is submitted in response to EPA's final decision to partially disapprove the Oklahoma Regional Haze (RH) State Implementation Plan (SIP),[1] the related RH Federal Implementation Plan (FIP), and subsequent discussions between AEP/PSO, ODEQ, and EPA regarding how best to implement BART controls at Northeastern. In the FIP, EPA evaluated Dry Flue Gas Desulfurization (DFGD) technology as compared to Wet FGD (WFGD). AEP/PSO agrees with EPA that DFGD is the appropriate selection between the two and no further analysis of WFGD is required. This submittal considers an alternative to the DFGD determined as BART in the FIP by evaluating Dry Sorbent Injection (DSI) as the SO_2 control technology combined with specific retirement dates for the Northeastern 3 and 4 Units. The discussions herein focus on an option that would allow AEP/PSO to proceed with terms and conditions laid out in the Settlement Agreement included in Appendix C to this report as opposed to the RH FIP. The key differences between the FIP and the Settlement Agreement are summarized below:

▲ FIP: Install and operate DFGD, with an emission limit of 0.06 lb/MMBtu, on both units
▲ Settlement Agreement: Shut down one of the two units by April 16, 2016 and install and operate a dry sorbent injection system (DSI), with an emission limit of 0.4 lb/MMBtu, on the other unit from April 16, 2016 to December 31, 2026, at which point the unit will also shut down

This report compares the two SO_2 control options described above by evaluating the cost effectiveness of both options and by evaluating the improvement to the existing visibility impairment for both options. Also, because the Settlement Agreement option includes the shutdown of the units, which changes the NO_X emission rates (to zero) as well, AEP/PSO has re-evalauted, and is presenting new results, of the visibility impairment associated with the NO_X BART determinations.

The modeling methods relied upon for evaluating the visibility impairment are largely the same as the methodology that was relied upon in the previous BART report. Exceptions are described in Section 2 of this report.

[1] 77 FR 16168-16197

2. Modeling Methodology

The modeling inputs, methods, and results presented in this report followed the methods and procedures that were previously used, and approved, with a few exceptions. The changes for the current modeling compared to the modeling originally submitted are listed below. Since the changes primarily involve how the CALPOST model was applied, a detailed description of the CALPOST methods is provided in Section 2.1.

- ▲ The postprocessor POSTUTIL (Version 1.52, Level 060412) was used to repartition nitrates from the CALPUFF output file to be consistent with the total available sulfate and ammonia, prior to assessing visibility with CALPOST. Note that POSTUTIL is not among the list of regulatory models on EPA's SCRAM website. Thus, there is no regulatory approved (or default) version of POSTUTIL.
- ▲ The CALPOST model version was updated to Version 6.221, Level 080724.
- ▲ The CALPOST visibility calculation method was updated from Method 6 to Method 8. Method 8 incorporates the use of the new IMPROVE (Interagency Monitoring of Protected Visual Environments) equation for predicting light extinction, as found in the 2010 FLAG (Federal Land Managers Air Quality Related Values Workgroup) guidance.
- ▲ The annual average background concentrations used in the CALPOST models for each of the four Class I Areas of interest – Caney Creek Wilderness (CACR), Hercules Glades Wilderness (HERC), Upper Buffalo Wilderness (UPBU), and Wichita Mountains National Wildlife Refuge (WICH) – were updated based on values found in the 2010 FLAG guidance.

The CALMET processing was not updated as a part of the analyses presented in this report. That is, the same meteorological dataset used in the original (2008) analyses was used again. This dataset was processed using CALMET v.5.53a. Re-processing of the meteorological data is not prudent for the reasons listed below.

- ▲ The intent of this report is to provide supplemental information for comparative purposes; therefore, it is important to maintain consistency with past analyses where possible.
- ▲ It is expected that changes to the CALMET processing would not significantly impact the BART analysis metric since that metric is a relative comparison, i.e., the CALMET change would apply to both baseline and post-control modeling.
- ▲ Creating a new meteorological dataset would take several months.
- ▲ Re-running CALMET would require development of a new protocol and potential lengthy negotiations of numerous user-defined values for which EPA may or may not have published guidance since the original analysis. As an example, AEP/PSO is familiar with EPA's August 2009 memo regarding CALMET settings in which EPA provides recommendations (but not defaults) for R and RMAX values.
- ▲ The existing meteorological dataset has been recently reviewed and approved for use by EPA numerous times for AEP and for several other facilities in EPA Region 6.

2.1 CALPOST

The CALPOST visibility processing completed for this BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG). The

2010 FLAG guidance, which was issued in draft form on July 8, 2008 and published as final guidance in December 2010, makes technical revisions to the previous guidance issued in December 2000.

Visibility impairment is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index expressed in deciviews (dv). The haze index (*HI*) is calculated as follows:

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

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to as "delta dv," or Δdv, based on the source and background light extinction is based on the following equation:

$$\Delta \text{dv} = 10 * \ln\left[\frac{\text{b}_{\text{ext, background}} + \text{b}_{\text{ext, source}}}{\text{b}_{\text{ext, background}}}\right]$$

The Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup adopted an equation for predicting light extinction as part of the 2010 FLAG guidance (often referred to as the new IMPROVE equation). The new IMPROVE equation is as follows:

$$b_{ext} = \begin{array}{l} 2.2\, f_S(RH)\left[\text{NH}_4(\text{SO}_4)_2\right]_{\text{Small}} + 4.8\, f_L(RH)\left[\text{NH}_4(\text{SO}_4)_2\right]_{\text{Large}} + \\ 2.4\, f_S(RH)\left[\text{NH}_4\text{NO}_3\right]_{\text{Small}} + 5.1\, f_L(RH)\left[\text{NH}_4\text{NO}_3\right]_{\text{Large}} + \\ 2.8[\text{OC}]_{\text{Small}} + 6.1[\text{OC}]_{\text{Large}} + 10[\text{EC}] + 1[\text{PMF}] + 0.6[\text{PMC}] + \\ 1.4\, f_{SS}(RH)[\text{Sea Salt}] + b_{\text{Site-specific Rayleigh Scattering}} + 0.33[\text{NO}_2] \end{array}$$

Visibility impairment predictions relied upon in this BART analysis used the equation shown above. The use of this equation is referred to as "Method 8" in the CALPOST control file. The use of Method 8 requires that one of five different "modes" be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. "Mode 5" has been used in this BART analysis. Mode 5 addresses moisture in the atmosphere in a similar way as to "Method 6", where "Method 6" is specified as the preferred approach for use with the old IMPROVE equation in the CENRAP BART modeling protocol.

CALPOST Method 8, Mode 5 requires the following:

▲ Annual average concentrations reflecting natural background for various particles and for sea salt
▲ Monthly RH factors for large and small ammonium sulfates and nitrates and for sea salts
▲ Rayleigh scattering parameter corrected for site-specific elevation

Tables 2-1 to 2-4 below show the values for the data described above that were input to CALPOST for use with Method 8, Mode 5. The values were obtained from the 2010 FLAG guidance.

TABLE 2-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

Class I Area	$(NH_4)_2SO_4$ (µg/m^3)	NH_4NO_3 (µg/m^3)	OM (µg/m^3)	EC (µg/m^3)	Soil (µg/m^3)	CM (µg/m^3)	Sea Salt (µg/m^3)	Rayleigh (Mm^{-1})
CACR	0.23	0.1	1.8	0.02	0.5	3	0.03	11
UPBU	0.23	0.1	1.8	0.02	0.5	3	0.03	11
HERC	0.23	0.1	1.8	0.02	0.5	3	0.02	11
WICH	0.12	0.1	0.6	0.02	0.5	3	0.03	11

TABLE 2-2. FL(RH) LARGE RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
UPBU	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
HERC	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
WICH	2.39	2.25	2.10	2.11	2.39	2.24	2.02	2.13	2.35	2.22	2.28	2.41

TABLE 2-3. F_S(RH) SMALL RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
UPBU	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
HERC	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
WICH	3.17	2.94	2.69	2.68	3.15	2.86	2.49	2.70	3.07	2.87	2.97	3.20

TABLE 2-4. F_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
CACR	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
UPBU	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.7	3.84	3.64	3.67	3.86
HERC	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
WICH	3.35	3.12	2.91	2.94	3.40	3.21	2.84	3.01	3.32	3.10	3.20	3.40

3. SUPPLEMENTAL INFORMATION FOR THE NO_X BART DETERMINATION

EPA has approved as BART a NO_X emission rate of 0.15 lb/MMBtu.[2] Even though the NO_X BART determination is final, as part of this report AEP/PSO is re-modeling in order to consider the impact of the unit shutdowns prescribed by the Settlement Agreement, and also in order to use the updated version of CALPOST as described in Section 2. This will allow for an apples-to-apples comparison of the NO_X BART determination visibility impact associated with the SO_2 controls that are the primary focus of this report.

Table 3-1 shows a summary of visibility improvement, based on the updated modeling, attributable to a NO_X emission rate of 0.15 lb/MMBtu for Unit 3 plus the shutdown of Unit 4. Detailed year-by-year modeling results are presented in Appendix B.

TABLE 3-1. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SCENARIO

	Baseline			Unit 4 Shutdown / Unit 3 NO_X Controlled, SO_2 Baseline		
Class I Area	**Max. Impact (Δdv)**	**98th %-tile (Δdv)**	**# Days > 0.5 Δdv**	**Max. Impact (Δdv)**	**98th %-tile (Δdv)**	**# Days > 0.5 Δdv**
CACR	3.710	1.927	121	1.738	0.609	26
HERC	3.683	1.291	85	1.758	0.595	23
UPBU	5.196	1.389	87	2.453	0.563	20
WICH	5.480	1.937	106	2.509	0.865	31

Table 3-1a presents the emission rates input in the modeling that resulted in the output presented in Table 3-1.

TABLE 3-1a. SUMMARY OF EMISSION RATES USED IN BASELINE AND NO_X CONTROL SCENARIO

Scenario	Unit	NO_X (lb/MMBtu)	NO_X (lb/hr)	SO_2 (lb/MMBtu)	SO_2 (lb/hr)	SO_4 (lb/MMBtu)	SO_4 (lb/hr)
Baseline	Unit 3	0.536	3,115.5	1.054	6,126.3	0.011	66.3
	Unit 4	0.491	2,746.6	1.060	5,929.6	0.011	62.3
Unit 4 Shutdown / Unit 3 NO_X Controlled, SO_2 Baseline	Unit 3	0.15	871.9	1.054	6,126.3	0.011	66.3
	Unit 4	0	0	0	0	0	0

[2] 77 FR 16168-16197

4. SUPPLEMENTAL INFORMATION FOR THE SO_2 BART DETERMINATIONS

This section provides supplemental information regarding SO_2 control options prescribed in the above-mentioned Settlement Agreement scenario and the FIP scenario.

- FIP Scenario: Install and operate DFGD, with an emission limit of 0.06 lb/MMBtu, on both Unit 3 and Unit 4
- Settlement Agreement Scenario: Shut down Unit 4 by 2016 and install and operate DSI, with an emission limit of 0.4 lb/MMBtu, on Unit 3 from 2016 to 2026, at which point it will also shut down

Because the Settlement Agreement scenario involves the immediate (in 2016) shutdown of Unit 4 and, for Unit 3, a phased reduction in operations (from 2016 to 2026), the evaluations completed in this report – the cost effectiveness evaluation and the visibility impairment evaluation – are completed on a scenario basis rather than a unit-by-unit basis. These evaluations are described below following a brief description of the two SO_2 control options being considered.

DRY SORBENT INJECTION

Dry sorbent injection (DSI) involves the injection of a sorbent, or reagent, (e.g., sodium bicarbonate) into the exhaust gas stream upstream of a particulate control device. The SO_2 reacts with the reagent and the resulting particle is collected in the particulate control system. The process was developed as a lower cost Flue Gas Desulfurization (FGD) option because the existing ductwork acts as the absorber vessel, obviating the need to install a new, separate absorber vessel. Depending on the residence time, gas stream temperature, and limitations of the particulate control device, sorbent injection control efficiency can range between 40 and 60 percent.[3] This control is a technically feasible option for the control of SO_2 for Unit 3.

DRY FLUE GAS DESULFURIZATION

There are various designs of dry flue gas desulfurization (DFGD) systems. In the spray dryer absorber (SDA) design, a fine mist of lime slurry is sprayed into an absorption vessel where the SO_2 is absorbed by the slurry droplets. The absorption of the SO_2 leads to the formation of calcium sulfite and calcium sulfate within the droplets. The liquid-to-gas ratio is such that the heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the vessel. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter.

In the circulating dry scrubbing (CDS) process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle; the exhaust is mixed with water, hydrated lime, recycled flyash and CDS reaction products. The intensive gas-solid mixing that occurs in the reactor promotes the reaction of sulfur oxides in the flue gas with the dry lime particles. The mixture of

[3] "Assessment of Control Technology Options for BART-Eligible Sources: Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities" Northeast States for Coordinated Air Use Management (NESCAUM), March 2005.

reaction products (calcium sulfite/sulfate), unreacted lime, and fly ash is carried out with the exhaust and collected in an ESP or fabric filter. A large portion of the collected particles is recycled to the reactor to sustain the bed and improve lime utilization.

DFGD control efficiencies range from 60 to 95 percent.[4] This is a technically feasible option for the control of SO_2 for Unit 3.

4.1 COST EFFECTIVENESS EVALUATION

See Appendix A for the detailed cost breakdown.

The capital and operating costs of the DSI control option, i.e., the Settlement Agreement scenario, were estimated based on EPA's Control Cost Manual ("the Manual") except as listed below.

- *Purchased Equipment Costs*, *Site Preparation Costs*, and *Building Costs* were based on an approximate six-month, site-specific, feasibility and conceptual engineering and design effort that resulted in the a Class 4 AACE category budgetary estimate.
- *Operating Labor Costs*, *Maintenance Labor Costs*, and *Other Direct Operating Costs* (e.g., for sorbent usage, electricity, and bag and cage replacement) were based on an evaluation of annual operating and maintenance cost project impact as part of the above-mentioned feasibility and conceptual design effort.
- The *Indirect Operating Costs* of *Overhead*, *Property Tax*, and *Insurance* were based on the same calculation methodologies presented in EPA's Technical Support Document (TSD) published with the RH FIP. These methodologies deviate from the Manual but were used for the purpose of consistency with the FIP.

The capital costs were annualized over a 10-year period and then added to the annual operating costs to obtain the total annualized costs. An equipment life of 10 years was used because the controls will only be in operation for 10 years, from 2016 to 2026, before the unit is shutdown.

In addition to the Manual-based estimates for DSI on one unit, AEP/PSO has provided, for comparison purposes, the cost estimate for a DSI control system based on an engineering analysis completed by AEP. To illustrate the difference, notice that the Manual-based estimate results in a total capital investment of approximately \$111 million whereas the engineering estimate is approximately \$163 million. Despite this difference, per previous discussions with ODEQ and EPA, AEP strictly used the Manual-based estimates in all cost effectiveness and incremental cost effectiveness calculations. The resulting total annual cost of control for the Settlement Agreement scenario is approximately \$25 million.

The costs presented for DFGD, i.e., the FIP scenario, were taken from EPA's Technical Support Document (TSD) published with the RH FIP. These costs also follow the Manual with a few exceptions that are footnoted in Appendix A. The total capital investment for DFGD for two units is

[4] EPA Basic Concepts in Environmental Sciences, Module 6: Air Pollutants and Control Techniques http://www.epa.gov/eogapti1/module6/sulfur/control/control.htm

taken to be approximately $274 million, and the total annual cost of control is taken to be approximately $45 million.

AEP/PSO commented on EPA's draft FIP (on May 23, 2011) stating, "EPA's Cost Effectiveness Analysis significantly underestimates the costs of [DFGD] controls," and this assertion is reiterated here. The cost estimate relied on by EPA was not developed specifically for PSO's Northeastern units but derived from a critique of the cost estimates presented in the Oklahoma SIP for Oklahoma Gas and Electric's (OG&E's) Sooner and Muskogee units. Once EPA derived its own estimates for DFGD at the Sooner and Muskogee units, EPA applied that estimate to the Northeastern units without taking into account any of the site-specific information presented in the original BART submittals.

Since the submittal of the original BART reports, AEP has completed a more detailed cost estimate for a DFGD system at a similar facility, including the development of current estimates for removal and foundations, direct equipment purchases, detailed design and engineering, and specialty subcontracts (electrical, civil, and instrumentation and controls). These estimates confirm that the cost figures relied on in the RH FIP are significantly understated. AEP/PSO is providing – for comparison purposes – this recent engineering cost analysis for DFGD. This analysis results in a total capital investment value of approximately $390 million (for one unit only).

The calculation of annual tons reduced for the Settlement Agreement scenario was completed by subtracting the estimated total controlled annual emission rate from the baseline total annual emission rate. The baseline total emission rate was based on each 4,775-MMBtu/hr unit operating at an 85 percent capacity utilization with an SO_2 emission rate of 0.9 lb/MMBtu.[5] The total controlled annual emission rate was calculated based on a DSI emission rate of 0.4 lb/MMBtu and in accordance with the Settlement Agreement-required schedule of capacity utilization reductions.

Lastly, the cost effectiveness values, in dollars per ton of SO_2 removed, were calculated by dividing the annual cost of control by the annual tons reduced. The resulting cost effectiveness values are: for the Settlement Agreement scenario, $942/ton, and for the FIP scenario, $1,544/ton. An incremental cost analysis was also performed to show the incremental increase in costs between the scenarios. The result is that the incremental FIP scenario cost is $7,794/ton more than the Settlement Agreement scenario.

[5] The use of a 0.9-lb/MMBtu baseline emission rate is consistent with EPA's use of this emission rate in its FIP and TSD. Moreover, this emission rate is the appropriate emission rate as it is reflective of the baseline period based on CEMS data. The interim reductions to 0.6 lb/MMBtu and 0.65 lb/MMBtu established in the Settlement Agreement are reflected in the cumulative reductions analyzed in this report.

4.2 EVALUATION OF VISIBILITY IMPACTS

An initial impact analysis was conducted to assess the visibility improvement related to SO_2 reductions based on the shut down of Unit 4 and installation of DSI on Unit 3. Table 4-2 provides a summary comparison of impacts in terms of the maximum modeled visibility impact, the 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv. Detailed year-by-year modeling results are presented in Appendix B.

TABLE 4-1. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH DSI SO_2 CONTROL ON UNIT 3 AND SHUTDOWN OF UNIT 4

Class I Area	Baseline Max. Impact (Δdv)	Baseline 98th %-tile (Δdv)	Baseline # Days > 0.5 Δdv	Unit 4 Shutdown / Unit 3 SO_2 Controlled (DSI), NO_X Baseline Max. Impact (Δdv)	Unit 4 Shutdown / Unit 3 SO_2 Controlled (DSI), NO_X Baseline 98th %-tile (Δdv)	Unit 4 Shutdown / Unit 3 SO_2 Controlled (DSI), NO_X Baseline # Days > 0.5 Δdv
CACR	3.710	1.927	121	1.131	0.637	25
HERC	3.683	1.291	85	1.300	0.408	14
UPBU	5.196	1.389	87	1.829	0.534	13
WICH	5.480	1.937	106	1.932	0.618	21

Table 4-1a presents the emission rates input in the modeling that resulted in the output presented in Table 4-1.

TABLE 4-1a. SUMMARY OF EMISSION RATES USED IN BASELINE AND SO_2 CONTROL SCENARIO INVOLVING DSI AND UNIT SHUTDOWNS

Scenario	Unit	NO_X (lb/MMBtu)	NO_X (lb/hr)	SO_2 (lb/MMBtu)	SO_2 (lb/hr)	SO_4 (lb/MMBtu)	SO_4 (lb/hr)
Baseline	Unit 3	0.536	3,115.5	1.054	6,126.3	0.011	66.3
	Unit 4	0.491	2,746.6	1.060	5,929.6	0.011	62.3
Unit 4 Shutdown / Unit 3 SO_2 Controlled (DSI), NO_X Baseline	Unit 3	0.536	3,115.5	0.4	2,325.0	0.004	25.1
	Unit 4	0	0	0	0	0	0

Further analysis was completed to compare the Settlement Agreement scenario, as a whole, and the FIP scenario. This analysis, the results of which are summarized in Table 4-3, included post-control rates for both SO_2 and NO_X for each scenario. Detailed year-by-year modeling results are presented in Appendix B.

TABLE 4-2. SUMMARY OF VISIBILITY IMPROVEMENT – COMPARISON OF SCENARIOS

Class I Area	Settlement Agreement Scenario Max. Impact (Δdv)	98th %-tile (Δdv)	# Days > 0.5 Δdv	FIP Scenario Max. Impact (Δdv)	98th %-tile (Δdv)	# Days > 0.5 Δdv
CACR	0.778	0.346	5	0.577	0.277	2
HERC	0.814	0.246	3	0.531	0.197	3
UPBU	1.152	0.247	4	0.783	0.238	3
WICH	1.194	0.372	6	0.867	0.257	1

Table 4-2a presents the emission rates input in the modeling that resulted in the output presented in Table 4-2.

TABLE 4-2a. SUMMARY OF EMISSION RATES USED IN SETTLEMENT AGREEMENT AND FIP SO_2 CONTROL SCENARIOS

Scenario	Unit	NO_X (lb/MMBtu)	NO_X (lb/hr)	SO_2 (lb/MMBtu)	SO_2 (lb/hr)	SO_4 (lb/MMBtu)	SO_4 (lb/hr)
Settlement Agreement Scenario	Unit 3	0.15	871.9	0.4	2,325.0	0.004	25.1
	Unit 4	0	0	0	0	0	0
FIP Scenario	Unit 3	0.15	871.9	0.06	348.7	0.001	3.8
	Unit 4	0.15	839.1	0.06	335.6	0.001	3.5

As shown in Table 4-2, both the FIP scenario and the Settlement Agreement scenario show 98th percentile impact values of well below 0.5 Δdv for all Class I areas. Moreover, the differences in the 98th percentile values between the two scenarios are very small, varying between from 0.01 to 0.12 Δdv depending on Class I area. Also, the Settlement Agreement scenario represents a substantial reduction, 80 to 82 percent depending on the Class I area, in visibility impairment compared to the baseline.

In addition, while the FIP scenario will have somewhat lower impacts until 2026, the visibility impact from the Settlement Agreement scenario will be zero after 2026 with the full retirement of both units compared to continued operation of two controlled units under the FIP scenario. It is also interesting to note that the total post-2014 emissions, in total tons, for the two scenarios are similar with the Settlement Agreement scenario resulting in somewhat less emissions overall. For the period from 2014 to 2046, the FIP scenario would result in 127,997[6] tons of SO_2 overall, a reduction of 895,977 tons compared to the baseline emission rate applied to the same period. The Settlement Agreement scenario is expected to result in 109,851[7] tons of SO_2 overall, a reduction of 914,123 tons compared to the baseline emission rate. Thus, the Settlement Agreement scenario provides for removal of an additional 18,145 tons of SO_2 above and beyond the FIP scenario. Note that in regards to NO_X, even more drastic reductions are provided for by the shutdowns stipulated in the Settlement Agreement scenario compared to the FIP scenario.

[6] Based on both units emitting at 0.9 lb/MMBtu for two years and 0.06 lb/MMBtu for 30 years.
[7] Based on the tiered emission rate and capacity utilization requirements of the Settlement Agreement.

Lastly, it is important to note that because of the phase down and eventual shut down of both units in the Settlement Agreement scenario, in the interest of meeting overall Regional Haze goals, the Settlement Agreement scenario gets to the glide path in a quicker timeframe.

4.3 PROPOSED BART FOR SO_2

Although the temporarily lower emission rate associated with the FIP scenario provides for slight visibility improvement when compared to the Settlement Agreement scenario, the small improvement does not justify the incremental cost, both in terms of cost effectiveness and in terms of up-front capital costs.

Therefore, AEP/PSO concludes that the combination of emissions control and unit retirements called for in the Settlement Agreement completely satisfy the BART requirements for Northeastern Station units 3 and 4. A summary of the requirements is provided below.

TABLE 4-3. SUMMARY OF PROPOSED SO_2 BART DETERMINATIONS

Emission Unit	BART Limit	Controls
Unit 4	Unit Shutdown by April 16, 2016	
Unit 3	0.4 lb/MMBtu 30-day rolling average	Dry Sorbent Injection, Unit Shutdown by December 31, 2026

APPENDIX A

SO_2 CONTROL COST CALCULATIONS

Estimated Average Cost ($/ton) of a Dry Sorbent Injection (DSI) System

Cost Type	Default Estimate Methodology from EPA's Control Cost Manual [a]	Cost Estimate Based on EPA's Control Cost Manual (One Unit)	*FOR COMPARISON* Cost Estimate Based on Engineering Study (2016$) (One Unit)
CAPITAL COSTS			
Direct Costs			
Purchased Equipment Costs (PEC)			
Equipment Cost (EC), including instrumentation	--	$49,883,940	$49,883,940
Sales Tax	3% of EC [b]	$0 [h]	$0 [h]
Freight	5% of EC [b]	$0 [h]	$0 [h]
Purchased Equipment Costs (PEC)		*$49,883,940*	*$49,883,940*
Direct Installation Costs			
Foundations and supports	6% of PEC [b]	$2,993,036	$11,433,582
Handling and erection	40% of PEC [b]	$19,953,576	$12,705,233
Electrical	1% of PEC [b]	$498,839	$8,181,380
Piping	5% of PEC [b]	$2,494,197	$9,536,419
Insulation for ductwork	3% of PEC [b]	$1,496,518	$3,181,956
Painting	1% of PEC [b]	$498,839	$1,232,111
Direct Installation Costs (DIC)		*$27,935,006*	*$46,270,680*
Other Direct Costs			
Site Preparation Costs (SPC)	--	$10,849,305	$10,849,305
Buildings Costs (BC)	--	$5,204,446	$5,204,446
Landfill Construction	--	$0 [i]	$0 [i]
Other Direct Costs (ODC)		*$16,053,751*	*$16,053,751*
Total Direct Capital Costs (DC = PEC + DIC + ODC)		*$93,872,698*	*$112,208,371*
Indirect Capital Costs			
Engineering	10% of PEC [b]	$4,988,394	$24,202,634
Construction and field expenses	10% of PEC [b]	$4,988,394	$8,977,897
Contractor fees	10% of PEC [b]	$4,988,394	$280,800
Start-up	1% of PEC [b]	$498,839	$3,562,477
Performance test	1% of PEC [b]	$498,839	$514,443
Contingencies	3% of PEC [b]	$1,496,518	$13,676,183
Total Indirect Capital Costs (IC)		*$17,459,379*	*$51,214,433*
TOTAL CAPITAL INVESTMENT (TCI = DC + IC)		*$111,332,077*	*$163,422,804*
OPERATING COSTS			
Direct Operating Costs			
Fixed O&M Costs (Labor and Materials)			
Operating Labor ($14.24/hour) [d]	8 hr/shift, 3 shifts/day [c]	$124,742	$997,939
Operating Labor Supervision	15% of op. labor [c]	$18,711	$0
Maintenance Labor ($14.24/hour) [d]	2 hr/shift, 3 shifts/day [c]	$31,186	$0
Maintenance materials	100% of maint. labor [c]	$31,186	$407,800
Fixed O&M Costs		*$205,825*	*$1,405,739*
Other Direct Operating Costs (e.g., utilities)			
Sorbent (22,776 tons/yr, $230/ton, Avg. CU) [e,f]	--	$3,500,257	$3,500,257
Electricity (5,696 kW/yr, $0.05588/kW, Avg. CU) [f]	--	$1,862,726	$1,862,726
Water (zero cost)	--	$0	$0
Waste Disposal (zero cost)	--	$0	$0
Bag and Cage Replacement (9,424 bags/cages;… …$114 & 3-yr cycle for bag; $29 & 6-yr cycle for cages)	--	$403,661	$403,661
Other Direct Operating Costs		*$5,766,644*	*$5,766,644*
Total Direct Operating Costs (DOC)		*$5,972,469*	*$7,172,383*
Indirect Operating Costs			
Overhead	60% of O&M [c]	$0 [j]	$0 [j]
Property tax	1% of TCI [c]	$946,323 [j]	$1,389,094 [j]
Insurance	1% of TCI [c]	$11,690 [j]	$17,159 [j]
Administration	2% of TCI [c]	$2,226,642	$3,268,456
Capital Recovery (10 years, 7 %) (CRF_{10})	0.1424 of TCI	$15,851,183	$23,267,731
Capital Recovery (30 years, 7 %) (CRF_{30})	0.0806 of TCI	--	--
Total Indirect Operating Costs (IOC)		*$19,035,837*	*$27,942,440*
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)		*$25,008,306*	*$35,114,823*

COST EFFECTIVENESS EVALUATION

Total Annual Cost of Control (DSI on Unit 3)		$25,008,306
Baseline SO_2 Emissions, TPY (at 0.9 lb/MMBtu for two units) [g]		31,999
Post-Control SO_2 Emissions, TPY (zero for one unit and decreasing over the 10-yr life for the controlled unit)…		
Year	Capcity Utilization	Emissions, TPY
2016, post-4/16	75	4,641
2017	75	6,274
2018	75	6,274
2019	75	6,274
2020	75	6,274
2021	70	5,856
2022	70	5,856
2023	60	5,019
2024	60	5,019
2025	50	4,183
2026	50	4,183
Average	66.8	5,441
Removed SO_2 Emissions, TPY		(26,558)
Cost/Ton Pollutant Removed (DSI-Controlled)		$942

[a] Default estimates are based on information published in the EPA Cost Control Manual, Sixth Edition. These estimates are used for all cost calculations except for the "Purchaed Equipment Costs," which are based on a six-month, site-specific, bottom-up engineering study; the "Other Direct Operating Costs" such as for sorbent usage, electricity, and bag and cage replacement; and the deviations discussed in note "j" below.

[b] EPA Cost Control Manual (CCM), Sixth Edition, Section 2.6.1.2, Table 2-8, p2-48.

[c] EPA Cost Control Manual, Sixth Edition, Table 2.9.

[d] Labor rates based on engineering estimates.

[e] The sorbent/reagent is sodium bicarbonate. The usage rate is based on average and maximum fuel-sulfur specifications of 0.8 and 0.9, respectively.

[f] The average capacity utilization, CU, over the 10-year life of the DSI is: 66.8%

[g] Based on a heat input capacity of 4,775 MMBtu/hr and a capacity utilization, CU, of 85 % (consistent with previous estimates).

[h] Sales tax and freight are included in the estimate of equipment cost (EC).

[i] No landfill construction costs are expected with the DSI option.

[j] In the FIP TSD, EPA used alternative (compared to the Control Cost Manual) estimates for these costs, i.e., zero for Overhead, 0.85 % of TCI for Property tax, and 0.0105 % of TCI for Insurance. These same estimates are used here for consistency.

Estimated Average Cost ($/ton) of a DFGD System

Cost Type	Cost Estimate Based on EPA's FIP TSD (Two Units)	Cost Estimate Based on EPA's FIP TSD (One Unit) *(all costs are assumed to be one-half of the costs for two units)*	*FOR COMPARISON* Cost Estimate Based on Engineering Study (2016$) (One Unit)
CAPITAL COSTS			
Direct Costs			
Purchased Equipment Costs (PEC)	*All Capital Costs except landfill construction were included in a single PEC value.*		
Equipment Cost (EC), including instrumentation			$97,565,272
Sales Tax			$0
Freight			$4,911,062
Purchased Equipment Costs (PEC)	*$249,100,000*	*$124,550,000*	*$102,476,334*
Direct Installation Costs	*All Capital Costs except landfill construction were included in a single PEC value.*		
Foundations and supports			$24,696,782
Handling and erection			$52,073,459
Electrical			$14,145,234
Piping			$15,165,588
Insulation for ductwork			$10,808,407
Painting			$2,156,162
Direct Installation Costs (DIC)			*$119,045,632*
Other Direct Costs	--		
Site Preparation Costs (SPC)	--		$23,427,157
Buildings Costs (BC)	--		$22,601,520
Landfill Construction	$25,000,000	$12,500,000	$12,500,000
Other Direct Costs (ODC)	*$25,000,000*	*$12,500,000*	*$58,528,677*
Total Direct Capital Costs (DC = PEC + DIC + ODC)			*$280,050,643*
Indirect Capital Costs	*All Capital Costs except landfill construction were included in a single PEC value.*		
Engineering			$44,632,242
Construction and field expenses			$15,363,554
Contractor fees			$1,476,991
Start-up			$12,249,202
Performance test			$1,057,312
Contingencies			$0
Total Indirect Capital Costs (IC)			*$74,779,301*
TOTAL CAPITAL INVESTMENT (TCI = DC + IC)	*$274,100,000*	*$137,050,000*	*$354,829,944*
OPERATING COSTS			
Direct Operating Costs			
Fixed O&M Costs (Labor and Materials)	*All O&M costs were included in a single value.*		
Operating Labor			$884,000
Operating Labor Supervision			$1,331,000
Maintenance Labor			$1,997,000
Maintenance materials			$0
Fixed O&M Costs	$4,116,350	$2,058,175	*$4,212,000*
Other Direct Operating Costs (e.g., utilities)			
Sorbent	$6,178,600	$3,089,300	$4,157,485
Electricity	$3,022,200	$1,511,100	$4,730,400
Water	$423,100	$211,550	$453,050
Waste Disposal	$727,981	$363,991	$1,546,663
Bag and Cage Replacement	$572,000	$286,000	$483,000
Other Direct Operating Costs			
Total Direct Operating Costs (DOC)	*$15,040,231*	*$7,520,116*	*$19,794,598*
Indirect Operating Costs			
Overhead	$0 [i]	$0 [i]	$0 [i]
Property tax	$2,329,850 [i]	$1,164,925 [i]	$3,016,055 [i]
Insurance	$28,781 [i]	$14,390 [i]	$37,257 [i]
Administration	$5,482,000	$2,741,000	$7,096,599
Capital Recovery (10 years, 7 %) (CRF_{10})	--	--	--
Capital Recovery (30 years, 7 %) (CRF_{30})	$22,088,733	$11,044,367	$28,594,469
Total Indirect Operating Costs (IOC)	*$29,929,364*	*$14,964,682*	*$38,744,380*
TOTAL ANNUALIZED COSTS (TAC = DOC + IOC)	*$44,969,595*	*$22,484,797*	*$58,538,978*
COST EFFECTIVENESS EVALUATION			
Total Annual Cost of Control	$44,969,595	$22,484,797	$58,538,978
Removed SO_2 Emissions, TPY	(29,119)	(14,560)	(14,933)
Cost/Ton Pollutant Removed	$1,544	$1,544	$3,920

APPENDIX B

DETAILED MODELING RESULTS TABLES

DETAILED RESULTS – BASELINE
(summary of which is presented in Table 3-1 and Table 4-1)

	2001			2002			2003			Total	Highest	Highest
Class I Area	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)
CACR	37	1.927	3.100	41	1.290	3.710	43	1.664	3.004	121	1.927	3.710
HERC	34	1.179	2.528	23	0.867	2.576	28	1.291	3.683	85	1.291	3.683
UPBU	32	1.389	2.938	25	0.938	1.800	30	1.180	5.196	87	1.389	5.196
WICH	28	1.228	5.480	34	1.339	2.429	44	1.937	3.424	106	1.937	5.480

DETAILED RESULTS – UNIT 4 SHUTDOWN / UNIT 3 NO_X CONTROLLED, SO_2 BASELINE
(summary of which is presented in Table 3-1)

	2001			2002			2003			Total	Highest	Highest
Class I Area	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)
CACR	10	0.609	1.324	8	0.513	1.738	8	0.533	1.257	26	0.609	1.738
HERC	9	0.520	1.086	3	0.366	1.039	11	0.595	1.758	23	0.595	1.758
UPBU	9	0.528	1.146	3	0.346	0.935	8	0.563	2.453	20	0.563	2.453
WICH	8	0.619	2.509	8	0.623	0.892	15	0.865	1.598	31	0.865	2.509

SUMMARY OF RESULTS – UNIT 4 SHUTDOWN / UNIT 3 SO_2 CONTROLLED (DSI), NO_X BASELINE
(summary of which is presented in Table 4-1)

	2001			2002			2003			Total	Highest	Highest
Class I Area	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)	# Days > 0.5 Δdv	98th %-tile (Δdv)	Max. Impact (Δdv)
CACR	9	0.637	1.118	6	0.439	1.131	10	0.584	0.993	25	0.637	1.131
HERC	5	0.408	1.019	4	0.291	0.872	5	0.298	1.300	14	0.408	1.300
UPBU	8	0.534	1.348	2	0.293	0.515	3	0.379	1.829	13	0.534	1.829
WICH	7	0.417	1.932	4	0.356	0.885	10	0.618	1.091	21	0.618	1.932

SUMMARY OF RESULTS – SETTLEMENT AGREEMENT SCENARIO
(summary of which is presented in Table 4-2)

	2001			2002			2003			Total	Highest	Highest
Class I Area	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**
CACR	2	0.346	0.637	1	0.240	0.778	2	0.297	0.585	5	0.346	0.778
HERC	0	0.213	0.483	0	0.170	0.496	3	0.246	0.814	3	0.246	0.814
UPBU	2	0.247	0.532	0	0.172	0.369	2	0.231	1.152	4	0.247	1.152
WICH	2	0.241	1.194	0	0.271	0.451	4	0.372	0.677	6	0.372	1.194

SUMMARY OF RESULTS – FIP SCENARIO
(summary of which is presented in Table 4-2)

	2001			2002			2003			Total	Highest	Highest
Class I Area	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**	**# Days > 0.5 Δdv**	**98^{th} %-tile (Δdv)**	**Max. Impact (Δdv)**
CACR	1	0.277	0.577	1	0.196	0.503	0	0.252	0.435	2	0.277	0.577
HERC	1	0.197	0.531	0	0.129	0.401	2	0.119	0.527	3	0.197	0.531
UPBU	2	0.238	0.735	0	0.129	0.257	1	0.139	0.783	3	0.238	0.783
WICH	1	0.187	0.867	0	0.163	0.427	0	0.257	0.478	1	0.257	0.867

APPENDIX C

SETTLEMENT AGREEMENT

SETTLEMENT AGREEMENT

This Settlement Agreement ("Agreement") is entered into by Public Service Company of Oklahoma ("PSO"), the Secretary of the Environment on behalf of the State of Oklahoma ("Secretary"), the Oklahoma Department of Environmental Quality ("ODEQ"), the United States Environmental Protection Agency ("EPA"), and the Sierra Club. PSO, the Secretary, ODEQ, EPA, and the Sierra Club are hereinafter collectively referred to as "the Parties" for purposes of this Agreement.

RECITALS

A. On December 28, 2011, EPA issued a final rule entitled, "Approval and Promulgation of Implementation Plans; Oklahoma; Federal Implementation Plan for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determinations," 76 Fed. Reg. 81,728 (Dec. 28, 2011) (the "Final Rule").

B. The Final Rule partially approved and partially disapproved Oklahoma's state implementation plan ("SIP") submitted under the "visibility" and "interstate transport" provisions of the Clean Air Act ("CAA"), 42 U.S.C. § 7410, 7491, and 7492. The Final Rule included a federal implementation plan ("FIP") establishing Best Available Retrofit Technology ("BART") emission limitations on sulfur dioxide ("SO_2") for Units 3 and 4 of PSO's Northeastern plant ("PSO's Units") to address the visibility and interstate transport provisions of the CAA.

C. PSO desires to develop and implement a comprehensive strategy to comply with its obligations with respect to the visibility and interstate transport provisions of the CAA as well as its other obligations with respect to the CAA in a coordinated manner.

D. PSO intends to install low NOx combustion technologies on both of its Units, retire one of its Units, and install and operate on its other Unit a dry sorbent injection system and baghouse in order to achieve emissions rates that comply with the terms of this Agreement and with its obligations with respect to the visibility provisions of the CAA.

E. PSO intends to retire one of its Units and install and operate on its other Unit a dry sorbent injection system, a baghouse, and activated carbon injection to achieve emissions rates that comply with the Mercury & Air Toxics Standard that became effective April 16, 2012, 40 C.F.R. § 63.9984 ("the MATS Rule"). Properly designed and operated air pollution control systems consisting of dry sorbent injection system, baghouse, and activated carbon injection can achieve the MATS Rule emission limits. An EPA letter to the ODEQ and PSO dated July 18, 2012, expresses EPA's support of PSO's comprehensive strategy to use the technologies described in the Regional Haze Agreement referenced in Attachment A to this Agreement to achieve the emission limitations prescribed by the MATS Rule. The letter is attached to this Agreement as Attachment B.

F. On February 24, 2011, PSO timely filed a Petition for Review, challenging the issuance of the Final Rule in *Public Service Company of Oklahoma v. U.S. Environmental Protection Agency*, *et al.*, No. 12-9524. On March 26, 2012, Sierra Club filed a timely motion to intervene. The motion was granted March 27, 2012.

G. The CAA and EPA's regulations require States to develop SIPs to implement the CAA's provisions, including the CAA's visibility and interstate transport provisions. *See* 42 U.S.C. §§ 7410(a)(2)(D)(i)(II), (J), 7491(b)(2); 40 C.F.R. § 50.300(a). ODEQ is the administrative agency in the State of Oklahoma responsible for developing and proposing such SIPs. *See* 27A O.S. §§ 2-5-105(3), (20), 1-3-101(B)(8), 2-3-101(B)(2). The Secretary, as the Governor's designee for the State of Oklahoma, is responsible for submitting SIPs to EPA for review. *See* 40 C.F.R. Part 51, Appendix V, Section 2.1(a); 40 C.F.R. § 51.103(a). Because this Agreement requires ODEQ to develop and propose and the Secretary to submit SIP revisions to EPA under the visibility and interstate transport provisions of the CAA, and ODEQ and the Secretary prefer to regulate PSO under such SIP revisions rather than EPA's FIP, ODEQ and the Secretary have an interest in and are essential parties to this Settlement Agreement.

H. The Parties have negotiated in good faith and have determined that the settlement reflected in this Agreement is in the public interest. If approved and implemented as set forth herein, this Agreement will resolve PSO's Petition for Review.

I. This Agreement will not impact any other provisions of the Final Rule, and/or any other applicable federal, state, and local laws and regulations. No other claims will be affected by the resolution of the issues related to PSO's Units as set forth herein.

AGREEMENT

1. PSO, Sierra Club, and EPA agree that within ten (10) days after this Agreement is executed by the Parties (i.e., signed), but before finalization pursuant to Paragraph 16 of this Agreement, they will jointly move the Court for an order holding in abeyance PSO's Petition for Review pending implementation of the terms of the Agreement.

2. Within thirty (30) days of the effective date of this Agreement, PSO shall submit to ODEQ final and complete versions of all information and documentation (including technical supporting documentation for PSO's Units) necessary for the development of the SIP revisions referenced in Paragraphs 3 and 4.

3. No later than one hundred-twenty (120) days after PSO provides ODEQ with the information and documentation required in Paragraph 2, ODEQ will develop and propose a SIP revision under the visibility provisions of the CAA, 42 U.S.C. § 7491, and EPA's regional haze regulations, 40 C.F.R. § 51.308, that addresses PSO's Units ("Regional Haze SIP revision") in accordance with the provisions of Attachment A.

4. No later than one hundred-twenty (120) days after PSO provides ODEQ with the information and documentation required in Paragraph 2, ODEQ will develop and propose

a SIP revision under the interstate transport provisions of the CAA, 42 U.S.C. § 7410(a)(2)(D)(i)(II), that addresses PSO's Units ("Interstate Transport SIP revision") in accordance with the provisions of Attachment A.

5. No later than one hundred-twenty (120) days after PSO provides ODEQ with the information and documentation required in Paragraph 2, the Secretary shall provide the proposed SIP revisions required in Paragraphs 3 and 4 to EPA and request parallel processing of the SIP revisions from EPA pursuant to 40 C.F.R. Part 51, App. V, Section 2.3.

6. If ODEQ determines, at any time subsequent to PSO's submittal of all information and documentation for PSO's Units as required in Paragraph 2, that additional information and/or documentation is necessary in order to develop the SIP revisions referenced in Paragraphs 3 and 4, ODEQ shall provide PSO with a written request for such additional information and/or documentation with a copy to all Parties. The deadlines associated with the obligations under Paragraphs 3-5 of this Agreement shall be tolled during the period of time between the issuance of the written request and ODEQ's receipt of the requested information and/or documentation.

7. After the opportunity for public hearing and the close of Oklahoma's notice-and-comment period for the Regional Haze and Interstate Transport SIP revisions, but no later than ninety (90) days after the Secretary submits the request for parallel processing referenced in Paragraph 5, ODEQ will consider and if appropriate adopt the Regional Haze and Interstate Transport SIP revisions referred to in Paragraphs 3 and 4. If adopted, the Secretary will submit to EPA those SIP revisions.

8. The Regional Haze and Interstate Transport SIP revisions adopted and submitted to EPA under Paragraph 7 will include the provisions described in Attachment A to this Agreement unless the Parties, by written mutual agreement, amend the provisions described in Attachment A. If the Regional Haze and Interstate Transport SIP revisions adopted and submitted to EPA by the Secretary do not include the provisions described in Attachment A to this Agreement, PSO may file a motion to dissolve the stay of PSO's petition for review and request that a briefing schedule be set. PSO may also pursue any opportunities for administrative or judicial review of the Regional Haze and Interstate Transport SIP revisions adopted by ODEQ and submitted by the Secretary.

9. Within sixty (60) days of EPA's receipt of the final Regional Haze and Interstate Transport SIP revisions EPA will determine whether the revisions meet the requirements of the CAA consistent with 42 U.S.C. § 7410(k)(1)(B) ("completeness finding").

10. EPA will take final action on the Regional Haze and the Interstate Transport SIP revisions as soon as possible, but no later than six (6) months from the date of the completeness finding referred to in Paragraph 9 consistent with 42 U.S.C. § 7410(k)(2).

11. If EPA promulgates a final action approving the provisions of the Regional Haze and Interstate Transport SIP revisions included in Attachment A, as adopted and submitted to

EPA by Oklahoma, PSO, the Sierra Club, and EPA will promptly file a joint stipulation of dismissal of PSO's Petition for Review. The Parties agree that they will not challenge that portion of any final action issued by EPA that fully approves the Regional Haze and Interstate Transport SIP revisions as adopted and submitted to EPA by the Secretary that contain the provisions in Attachment A affecting PSO's Units.

12. Separately from the SIP process, PSO will report biannually to EPA (beginning in 2017 for the period 2015-2016, and every second year thereafter through the end of 2025 or 2026, whenever the last Northeastern unit is retired) on the energy produced by PSO's units and the sources of energy secured under PSO's long-term purchased power contracts. The initial report will include similar information for calendar years 2013-2014. Requests for proposals ("RFPs") for long-term purchase power contracts issued between 2013 and the date the reporting obligation ends will specifically seek bids for energy supplied by natural gas and renewable resources. The biannual reports will include copies of any RFPs issued during the reporting period, and a summary of the capacity or energy secured through any long-term power purchase agreements executed during the reporting period, including the unit(s) providing the purchased power, the amount of capacity or energy secured under the agreement, and the term of each agreement.

13. The Parties may, by written mutual agreement, extend the dates in Paragraphs 2-5, 7, and 9-10 by which actions must be taken to fulfill the Parties' respective obligations under this Agreement.

14. Nothing in the Regional Haze and Interstate Transport SIP revisions as adopted and submitted to EPA by Oklahoma or in this Agreement shall relieve PSO from its obligations to comply with all applicable federal, state, and local laws and regulations, including laws, regulations, and compliance deadlines that become applicable after the date of any revisions to Oklahoma's Regional Haze SIP that may be approved by EPA. Such laws and regulations include, but are not limited to, any EPA rule imposing requirements relevant to interstate transport under 42 U.S.C. § 7410(a)(2)(D) and the MATS Rule. Nothing in Oklahoma's Regional Haze SIP revision, including the BART determination for PSO's Units, should be construed to provide any relief from the emissions limits or deadlines specified in such regulations, including, but not limited to, deadlines for the installation of pollution controls required by any such regulations.

15. If EPA does not take final action approving those aspects of the Regional Haze and Interstate Transport SIP revisions that contain the provisions of Attachment A, as adopted and submitted to EPA by Oklahoma, PSO may file a motion to dissolve the stay of PSO's Petition for Review, and to request that a briefing schedule be set. EPA does not waive or limit any defense relating to such litigation. This shall be the only remedy for EPA's failure to fulfill its obligations under this Agreement. PSO and Sierra Club agree that contempt of court is not an available remedy under this Agreement.

16. The Parties agree and acknowledge that before this Agreement is final, EPA must provide notice in the Federal Register and an opportunity for public comment pursuant to CAA

section 113(g), 42 U.S.C. § 7413(g). EPA shall promptly submit said notice of this Agreement to the Federal Register after this Agreement is executed by the Parties (i.e., signed). After this Agreement has undergone an opportunity for notice and comment, the Administrator or the Attorney General, as appropriate, shall promptly consider any such written comments in determining whether to withdraw or withhold their consent to the Agreement, in accordance with section 113(g) of the CAA.
If the United States elects not to withdraw or withhold its consent to this Agreement, EPA shall provide written notice to the Parties as expeditiously as possible. This Agreement shall become final and effective on the date that EPA provides such written notice to the Parties. If EPA does not provide such written notice within sixty (60) days after the notice of the Agreement is published in the Federal Register, the sole remedy shall be the right to file a motion to dissolve the stay of the Petition for Review, and to request that a briefing schedule be set. EPA does not waive or limit any defense relating to such litigation. PSO and Sierra Club agree that contempt of court is not an available remedy under this Agreement.

17. No provision of this Agreement shall be interpreted as or constitute a commitment or requirement that the United States or any of its departments or agencies obligate or pay funds in contravention of the Anti-Deficiency Act, 31 U.S.C. § 1341 *et seq.*, or in violation of any other statue, law, or regulation.

18. Nothing in this Agreement shall be construed to limit or modify the discretion accorded to EPA, ODEQ, or the Secretary by statute, or by general principles of administrative law.

19. Nothing in this Agreement shall be construed to limit or modify the rights of PSO or Sierra Club to seek reconsideration or judicial review of any altered, amended or revised provisions of any final action that ODEQ or EPA may take that differ in any material respect from the provisions described in Attachment A (or as amended by mutual written agreement of the Parties pursuant to Paragraph 8).

20. The undersigned hereby certify that they are duly authorized to bind the Party on whose behalf this Agreement is executed to the terms of this Agreement.

21. The provisions of this Agreement shall apply to and be binding on the Parties, their successors and assigns.

22. This Agreement may be signed in counterparts, and such counterpart signatures shall be given full force and effect.

FOR PETITIONER PSO:

Dated: 10-17-12

J. Stuart Solomon

J. Stuart Solomon, President
Public Service Company of Oklahoma

FOR STATE OF OKLAHOMA:
SECRETARY OF THE ENVIRONMENT FOR
THE STATE OF OKLAHOMA

Dated: 10/1/12 Gary L Sherrer

FOR OKLAHOMA DEPARTMENT OF
ENVIRONMENTAL QUALITY:

Dated: 9-28-12 Steven A. Thompson

FOR U.S. ENVIRONMENTAL PROTECTION AGENCY:

IGNACIA S. MORENO
Assistant Attorney General
Environment and Natural Resources Division

Dated:__________ By: ____

STEPHANIE J. TALBERT
Environmental Defense Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. BOX 7611
Washington, DC 20044
(202) 514-2617
Fax: (202) 514-8865
Stephanie.Talbert@usdoj.gov

FOR INTERVENOR SIERRA CLUB:

Dated: 10/16/12

<u>ATTACHMENT A</u>

1. Oklahoma, through the Secretary, will submit to EPA a Regional Haze SIP revision that addresses PSO's Units and includes, among other things, the following elements:

   a. Oklahoma's SIP revision will include a Regional Haze Agreement ("RHA") entered into by ODEQ and PSO to effectuate the BART determination.

   b. The RHA will require that by no later than December 31, 2013, PSO will complete installation of low NOx combustion technologies and achieve a nitrogen oxide ("NOx") emission rate of 0.23 lb/MMBtu on a 30-day rolling average at each of PSO's Units.

   c. The RHA will require that beginning on January 31, 2014, PSO will comply with a new SO_2 emission rate at each of PSO's Units of 0.65 lb/MMBtu on a 30-day rolling average, and beginning on December 31, 2014, PSO will comply with a new SO_2 emission rate of 0.60 lb/MMBtu on a 12-month rolling average at each of PSO's Units. PSO will maintain those emission rates until controls are installed at one unit as provided in subparagraph (e), and the other unit is retired as provided in subparagraph (d). The RHA will include an alternative operating scenario that addresses potential service disruption of coal supplies during the time period between January 31, 2014 through April 16, 2016.

   d. The RHA will require that PSO seek all necessary regulatory approvals, and will retire one of the coal-fired generating units at Northeastern Station by April 16, 2016.

   e. The RHA will require that PSO seek all necessary regulatory approvals, and install and operate a dry-sorbent injection system, activated carbon injection system, and a fabric filter baghouse, and secure further NOx emission reductions by April 16, 2016 on the coal-fired generating unit at Northeastern Station that will continue to operate. After completion of the installation of the pollution controls required by this subparagraph, PSO will achieve a 0.15 lb/MMBtu emission rate for NOx on a 30-day rolling average basis, and a 0.40 lb/MMBtu emission rate for SO_2 on a 30-day rolling average basis.

   f. The RHA will require that during the first year of operation of the controls required under the RHA, PSO will develop and propose a monitoring program to test various operating profiles and other measures, to determine whether increased SO_2 removal efficiencies can be achieved during normal operations. Pursuant to the terms of the RHA, PSO will submit the monitoring program to EPA and ODEQ for review and will implement the monitoring program during the second and third years of operation of the dry sorbent injection system. PSO will evaluate and report the results of the monitoring program to EPA and ODEQ, and if that evaluation demonstrates that the technology is capable of sustainably achieving an emission rate of less than 0.37 lbs/MMBtu on a 30-day rolling average basis without (i) altering the unit's fuel supply, (ii) incurring additional capital costs, (iii) increasing operating expenses by more than a negligible amount, and/or (iv) adversely impacting overall unit operations, ODEQ will propose to revise the emission rate in the RHA by 60 percent of the difference between 0.40 and the demonstrated emission rate. Upon adoption after notice and opportunity for hearing, Oklahoma, through the Secretary, will submit a Regional Haze SIP revision to EPA for approval. If the demonstrated emission rate is 0.37 lbs/MMBtu or greater, no adjustment will be made to the RHA, and the emission rate from the operating Northeastern coal-fired generating unit in the RHA will remain 0.40 lbs/MMBtu.

g. The RHA will require that beginning in calendar year 2021, the Annual Capacity Factor (calculated for each calendar year as a percentage of MWH based on a rated capacity of 470 MW times 8760 hours) for the operating coal-fired generating unit at Northeastern Station will be reduced as follows:
    i. to no more than 70 percent in calendar years 2021 and 2022;
    ii. to no more than 60 percent in calendar years 2023 and 2024; and
    iii. to no more than 50 percent in calendar years 2025 and 2026.

h. The RHA will require that no later than December 31, 2026, PSO will retire the remaining operating coal-fired generating unit at Northeastern Station. However, in calendar year 2021, the RHA will require PSO to evaluate whether the projected generation from that unit can be replaced at lower or equal total projected costs from natural gas or renewable resources. Pursuant to the RHA, PSO will provide a copy of the evaluation to EPA and ODEQ. If power is available from such resources at a lower projected total cost (including consideration of PSO's need to recover its remaining investment in the units), then the operating unit will retire no later than December 31, 2025.

2. Oklahoma, through the Secretary, will submit to EPA an Interstate Transport SIP revision that addresses PSO's Units and includes, among other things, the following elements:

    a. An enforceable mechanism that addresses SO_2 reductions from sources other than those operated by PSO, to the extent necessary to achieve the anticipated visibility benefits from the 2018 regional modeling; and

    b. A provision requiring that the enforceable mechanism referred to in Paragraph 2(a) of this Attachment A be implemented if the SO_2 emission rate for the controlled unit at Northeastern is not reduced to 0.30 lbs/MMBtu or less as a result of the Paragraph 1(f) of this Attachment A.

120 East Sheridan | Suite 205 | Oklahoma City, OK 73104 | P (405) 228-3292 | F (918) 512-7084
trinityconsultants.com

Trinity Consultants

October 3, 2012

Ms. Lee Warden, P.E.
Supervisor, Engineering Section
Air Quality Division
Oklahoma Department of Environmental Quality
707 N. Robinson
Oklahoma City, OK 73101

Re: BART Resubmittal Modeling Protocol
Northeastern Power Station
American Electric Power (AEP) / Public Service Company of Oklahoma (PSO)

Dear Ms. Warden:

Trinity is pleased to submit the attached CALPUFF Modeling Protocol on behalf of American Electric Power (AEP) and the Public Service Company of Oklahoma (PSO). This protocol is submitted in response to the request for reconsideration and resubmittal of the Best Available Retrofit Technology (BART) determinations at the Northeastern Power Station by the Oklahoma Department of Environmental Quality (ODEQ) and the Environmental Protection Agency (EPA). AEP/PSO requests formal approval from ODEQ of the CALPUFF Modeling Protocol prior to the commencement of modeling efforts and submission of results. Also included with this submittal is a copy of the met data set to be used in conjunction with the current modeling efforts.

The BART modeling efforts will follow the procedures outlined in the enclosed CALPUFF Modeling Protocol. This protocol proposes to follow the same modeling procedures that were used in the original 2008 modeling, with the exception of the following four updates:

- The postprocessor POSTUTIL (Version 1.52, Level 060412) will be used to repartition nitrates from the CALPUFF output file to be consistent with the total available sulfate and ammonia, prior to assessing visibility with CALPOST.
- The CALPOST model version will be updated to Version 6.221, Level 080724.
- The CALPOST visibility calculation method will be updated from Method 6 to Method 8. Method 8 incorporates the use of the new IMPROVE (Interagency Monitoring of Protected Visual Environments) equation for predicting light extinction, as found in the 2010 FLAG (Federal Land Managers Air Quality Related Values Workgroup) guidance.
- The annual average background concentrations used in the CALPOST models for each of the four Class I Areas of interest (Caney Creek Wilderness, Hercules Glades Wilderness, Upper Buffalo Wilderness, and Wichita Mountains Wilderness) will be updated based on values found in the 2010 FLAG guidance.

If you have any questions or need additional information, please call me at (405) 228-3292 or Howard L. "Bud" Ground of PSO at (405) 841-1322.

Sincerely,

TRINITY CONSULTANTS

Jeremy Townley

Jeremy Townley
Senior Consultant

Encl: CALPUFF Modeling Protocol

CALPUFF Modeling Protocol
Best Available Retrofit Technology (BART) Determination
American Electric Power ■ Northeastern Power Plant

Prepared by:

Jeremy W. Jewell ▪ Manager of Consulting Services
Jeremy Townley ▪ Senior Consultant
Kara Gerlach ▪ Consultant

Trinity Consultants
120 East Sheridan
Suite 205
Oklahoma City, OK 73104
(405) 228-3292

October 3, 2012

Project 123701.0079

CALPUFF MODELING PROTOCOL
BEST AVAILABLE RETROFIT TECHNOLOGY (BART) DETERMINATION
AMERICAN ELECTRIC POWER ■ NORTHEASTERN POWER PLANT

Prepared by:

Jeremy W. Jewell ▪ Manager of Consulting Services
Jeremy Townley ▪ Senior Consultant
Kara Gerlach ▪ Consultant

TRINITY CONSULTANTS
120 East Sheridan
Suite 205
Oklahoma City, OK 73104
(405) 228-3292

October 3, 2012

Project 123701.0079

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1. INTRODUCTION

American Electric Power /Public Service Company of Oklahoma (AEP/PSO) operates the Northeastern Power Station, which is located at Section 4, T22N, R15E, in Rogers County, Oklahoma. The Northeastern Power Station is currently operating in accordance with Oklahoma Department of Environmental Quality (DEQ) Title V Operating Permit, 2003-410-TVR (M-2), issued in August 24, 2010. The Northeastern Power Station is considered eligible for the application of Best Available Retrofit Technology (BART) as part of the Environmental Protection Agency (EPA) Regional Haze Rule. This protocol describes the proposed methodology for conducting the CALPUFF BART modeling analysis for the AEP Northeastern Power Station. The protocol also includes a discussion of the post processing methodologies to be used in the refined modeling analysis for the Northeastern Power Station.

1.1 OBJECTIVE

The objective of this document is to provide a protocol summarizing the modeling methods and procedures that will be followed to complete a refined CALPUFF modeling analysis for the Northeastern Power Station. The modeling methods and procedures contained in this protocol will be used to determine appropriate controls for AEP's BART-eligible sources that can reasonably be anticipated to reduce the sources' effects on or contribution to visibility impairment in the surrounding Class I areas.

1.2 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

The sources listed in Table 1-1. BART-Eligible Sources are the sources that have been identified by AEP as sources that meet the three criteria for BART-eligible sources at the Northeastern Power Station.

TABLE 1-1. BART-ELIGIBLE SOURCES

EPN	Description
Unit 2	4,754 MMBtu/hr Gas-fired
Unit 3	4,775 MMBtu/hr Coal Fired Boiler
Unit 4	4,775 MMBtu/hr Coal Fired Boiler

As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following tables summarize the distances of the four closest Class I areas to the Northeastern Power Station. As seen from this summary, one Class I area (Wichita Mountains) is more than 300 km from the station, but has been included in the analysis. Note that the distances listed in the tables below are the distances between the stations and the closest border of the Class I areas.

TABLE 1-2. DISTANCE (KM) FROM STATION TO SURROUNDING CLASS I AREAS

Class I Area Name	Distance from Source (km)
Caney Creek Wilderness	263
Hercules-Glades Wilderness	244
Upper Buffalo Wilderness	211
Wichita Mountains Wilderness	323

2. CALPUFF MODEL SYSTEM

The main components of the CALPUFF modeling system are CALMET, CALPUFF, and CALPOST. CALMET is the meteorological model that generates hourly three-dimensional meteorological fields such as wind and temperature. CALPUFF simulates the non-steady state transport, dispersion, and chemical transformation of air pollutants emitted from a source in “puffs.” CALPUFF calculates hourly concentrations of visibility affecting pollutants at each specified receptor in a modeling domain. CALPOST is the post-processor for CALPUFF that computes visibility impacts from a source based on the visibility affecting pollutant concentrations that were output by CALPUFF.

Other components of the CALPUFF modeling system include geophysical data processors such as TERREL, CTGCOMP, CTGPROC, and MAKEGEO. These processors create a geophysical data file from land use and terrain data, which is then used in the CALMET model. Another important processor in the CALPUFF modeling system is the postprocessor POSTUTIL. POSTUTIL is used to repartition nitrates from the CALPUFF output file to be consistent with the total available sulfate and ammonia, prior to assessing visibility with CALPOST.

2.1 MODEL VERSIONS

The versions of the CALPUFF modeling system programs that will be used for conducting AEP’s BART modeling are listed in Table 2-1.

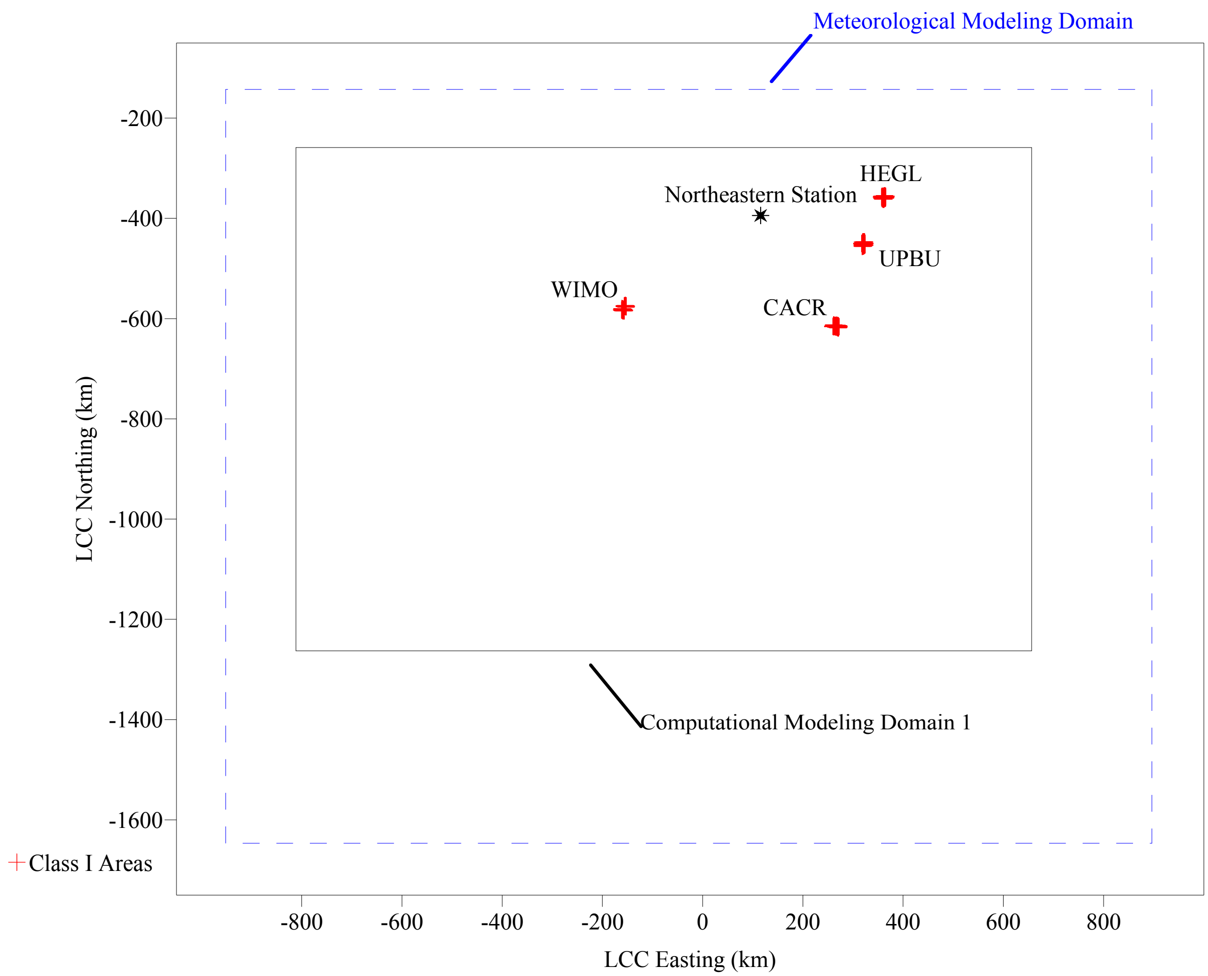
TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.52	060412
CALPOST	6.221	080724

2.2 MODELING DOMAIN

The CALPUFF modeling system utilizes three modeling grids: the meteorological grid, the computational grid, and the sampling grid. The meteorological grid is the system of grid points at which meteorological fields are developed with CALMET. The computational grid determines the computational area for a CALPUFF run. Puffs are advected and tracked only while within the computational grid. The meteorological grid is defined so that it covers the areas of concern and gives enough marginal buffer area for puff transport and dispersion. A plot of the meteorological modeling domain with respect to the Class I areas being modeled is provided in Figure 2-1. The computational domain will be set to extend at least 50 km in all directions beyond the Northeastern Power Station and the Class I areas of interest. Note that the map projection for the modeling domain will be Lambert Conformal Conic (LCC) and the datum will be the World Geodetic System 84 (WGS-84). The reference point for the modeling domain is Latitude 40ºN, Longitude 97ºW. The southwest corner will be set to -951.547 km LCC, -1646.637 km LCC corresponding to Latitude 24.813 ºN and Longitude 87.778ºW. The meteorological grid spacing will be 4 km, resulting in 462 grid points in the X direction and 376 grid points in the Y direction.

FIGURE 2-1. REFINED METEOROLOGICAL MODELING DOMAIN



3. CALMET

The EPA Approved Version of the CALMET meteorological processor will be used to generate the meteorological data for CALPUFF. CALMET is the meteorological processor that compiles meteorological data from raw observations of surface and upper air conditions, precipitation measurements, mesoscale model output, and geophysical parameters into a single hourly, gridded data set for input into CALPUFF. CALMET will be used to assimilate data for 2001- 2003 using National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, buoy station observations (for overwater areas), and mesoscale model output to develop the meteorological field.

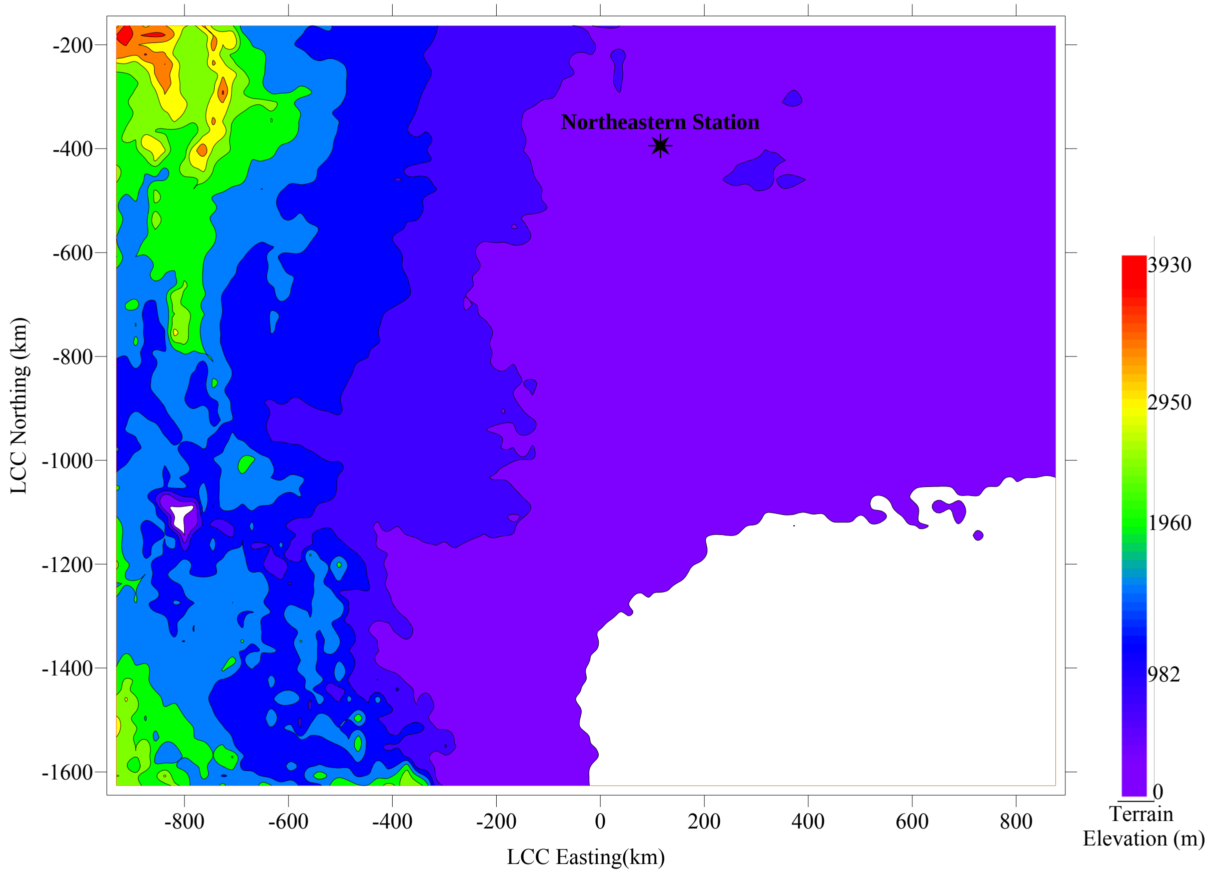
3.1 GEOPHYSICAL DATA

CALMET requires geophysical data to characterize the terrain and land use parameters that potentially affect dispersion. Terrain features affect flows and create turbulence in the atmosphere and are potentially subjected to higher concentrations of elevated puffs. Different land uses exhibit variable characteristics such as surface roughness, albedo, Bowen ratio, and leaf-area index that also effect turbulence and dispersion.

3.1.1 TERRAIN DATA

Terrain data will be obtained from the United States Geological Survey (USGS) in 1-degree (1:250,000 scale or approximately 90 meter resolution) digital format. The USGS terrain data will then processed by the TERREL program to generate grid-cell elevation averages across the modeling domain. A plot of the land elevations based on the USGS data for the modeling domain is provided in Figure 3-1.

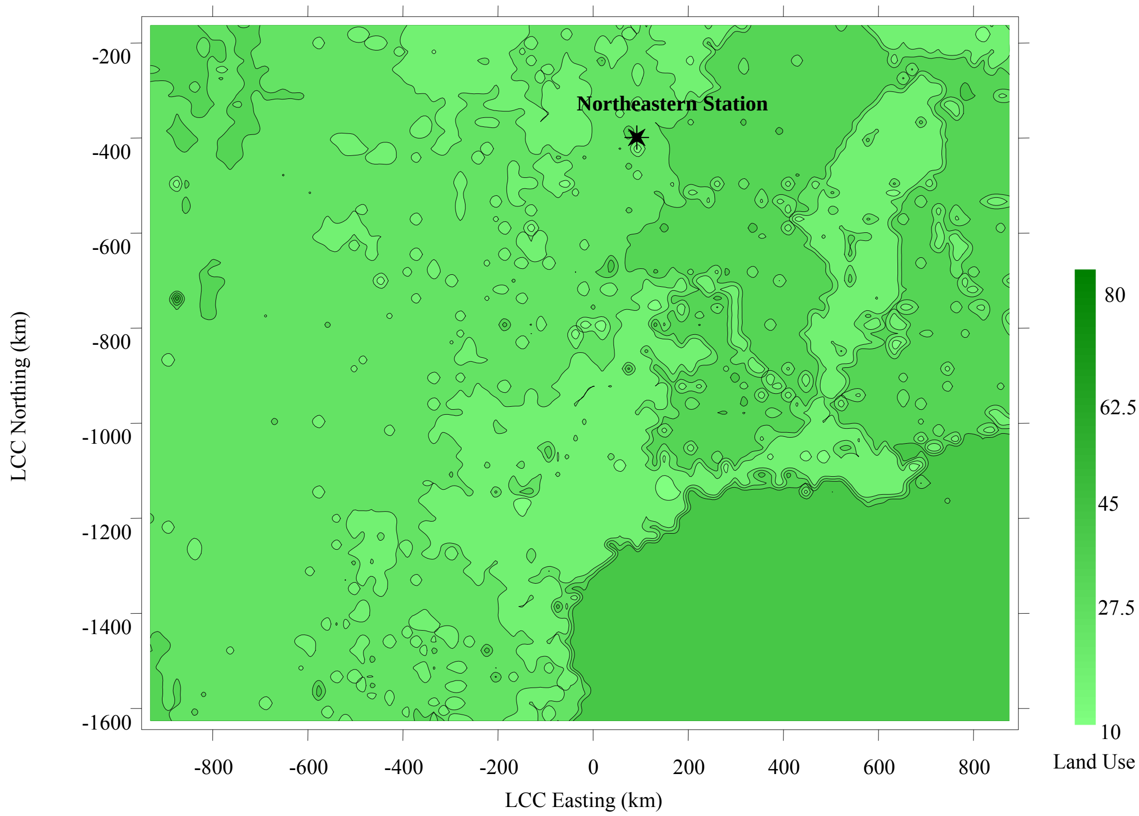
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



3.1.2 LAND USE DATA

The land use land cover (LULC) data from the USGS North American land cover characteristics data base in the Lambert Azimuthal equal area map projection will be used in order to determine the land use within the modeling domain. The LULC data will be processed by the CTGPROC program which generated land use for each grid cell across the modeling domain. A plot of the land use based on the USGS data for the modeling domain is provided in Figure 3-2.

FIGURE 3-2. PLOT OF LAND USE USING USGS LULC DATA



3.1.3 COMPILING TERRAIN AND LAND USE DATA

The terrain data files output by the TERELL program and the LULC files output by the CTGPROC program will be uploaded into the MAKEGEO program to create a geophysical data file that will be input into CALMET.

3.2 METEOROLOGICAL DATA

CALMET will be used to assimilate data for 2001, 2002, and 2003 using mesoscale model output and National Weather Service (NWS) surface station observations, upper air station observations, precipitation station observations, and National Oceanic and Atmosphere Administrations (NOAA) buoy station observations to develop the meteorological field.

3.2.1 MESOSCALE MODEL METEOROLOGICAL DATA

Hourly mesoscale data will also be used as the initial guess field in developing the CALMET meteorological data. It is AEP's intent to use the following 5th generation mesoscale model meteorological data sets (or MM5 data) in the analysis:

- 2001 MM5 data at 12 km resolution generated by the U.S. EPA
- 2002 MM5 data at 36 km resolution generated by the Iowa DNR

- 2003 MM5 data set at 36 km resolution generated by the Midwest RPO

The specific MM5 data that will be used are subsets of the data listed above. As the contractor to CENRAP for developing the meteorological data sets for the BART modeling, Alpine Geophysics extracted three subsets of MM5 data for each year from 2001 to 2003 from the data sets listed above using the CALMM5 extraction program. The three subsets covered the northern, central, and southern portions of CENRAP. AEP is proposing to use the southern set of the extracted MM5 data.

The 2001 southern subset of the extracted MM5 data includes 30 files that are broken into 10 to 11 day increments (3 files per month). The 2002 and 2003 southern subsets of extracted MM5 data include 12 files each of which are broken into 30 to 31 day increment files (1 file per month). Note that the 2001 to 2003 MM5 data extracted by Alpine Geophysics will not be able to be used directly in the modeling analysis. To run the Alpine Geophysics extracted MM data in the EPA approved CALMET program, each of the MM5 files will need to be adjusted by appending an additional six (6) hours, at a minimum, to the end of each file to account for the shift in time zones from the Greenwich Mean Time (GMT) prepared Alpine Geophysics data to Time Zone 6 for this analysis. No change to the data will occur.

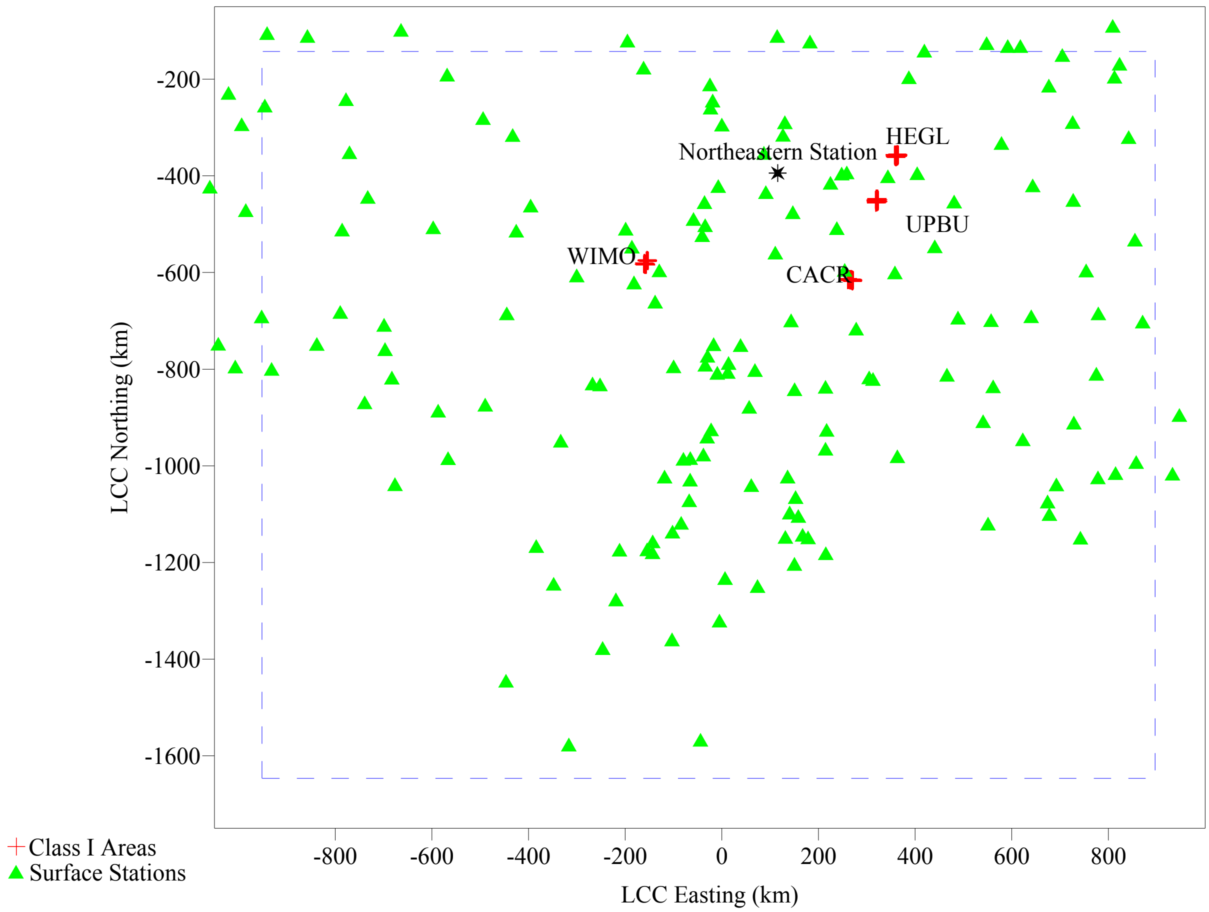
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard time (LST), which is necessary since the surface meteorological observations are recorded in LST, there must be hours of MM5 data referenced in a CALMET run that match the LST observation hours. Since the LST hours in Central Standard Time (CST) are 6 hours behind GMT, it is necessary to adjust the data in each MM5 file so that the time periods covered in the files match CST.

Based on the above discussion, the Alpine Geophysics MM5 data will not be used directly. Instead the data files will be modified to add 8 additional hours of data to the end of each file from the beginning of the subsequent file. CALMET will then be run using the appended MM5 data to generate a contiguous set of CALMET output files. The converted MM5 data files occupy approximately 1.2 terabytes (TB) of hard drive space.

3.2.2 SURFACE METEOROLOGICAL DATA

Parameters affecting turbulent dispersion that are observed hourly at surface stations include wind speed and direction, temperature, cloud cover and ceiling, relative humidity, and precipitation type. It is AEP's intent to use the surface stations listed in Table A-1 of Appendix A. The locations of the surface stations with respect to the modeling domain are shown in Figure 3-3. The stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's SMERGE program.

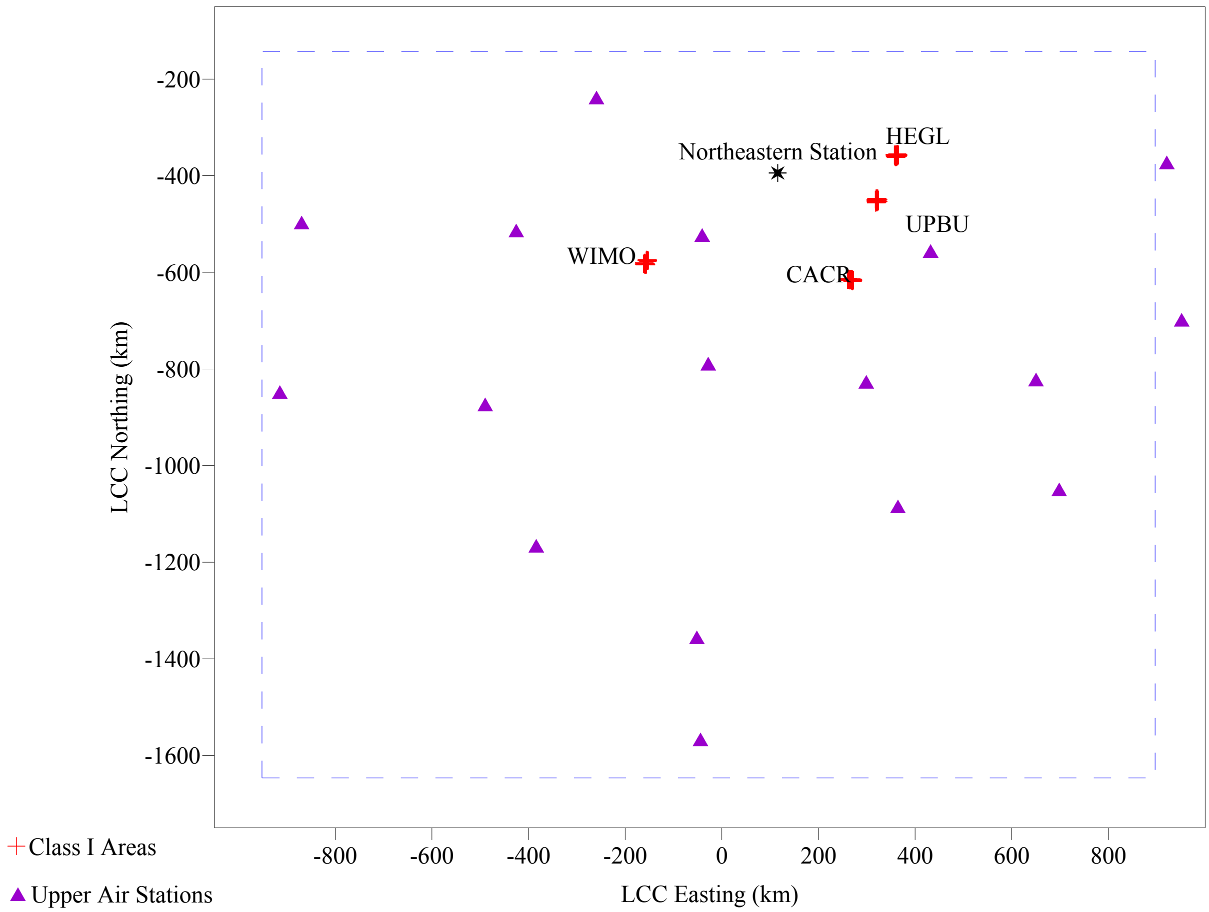
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



3.2.3 UPPER AIR METEOROLOGICAL DATA

Observations of meteorological conditions in the upper atmosphere provide a profile of turbulence from the surface through the depth of the boundary layer in which dispersion occurs. Upper air data are collected by balloons launched simultaneously across the observation network at 0000 Greenwich Mean Time (GMT) (6 o'clock PM in Oklahoma) and 1200 GMT (6 o'clock AM in Oklahoma). Sensors observe pressure, wind speed and direction, and temperature (among other parameters) as the balloon rises through the atmosphere. The upper air observation network is less dense than surface observation points since upper air conditions vary less and are generally not as affected by local effects (e.g., terrain or water bodies). The upper air stations that are proposed for this analysis are listed in Table A-2 of Appendix A. The locations of the upper air stations with respect to the modeling domain are shown in Figure 3-4. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's READ62 program.

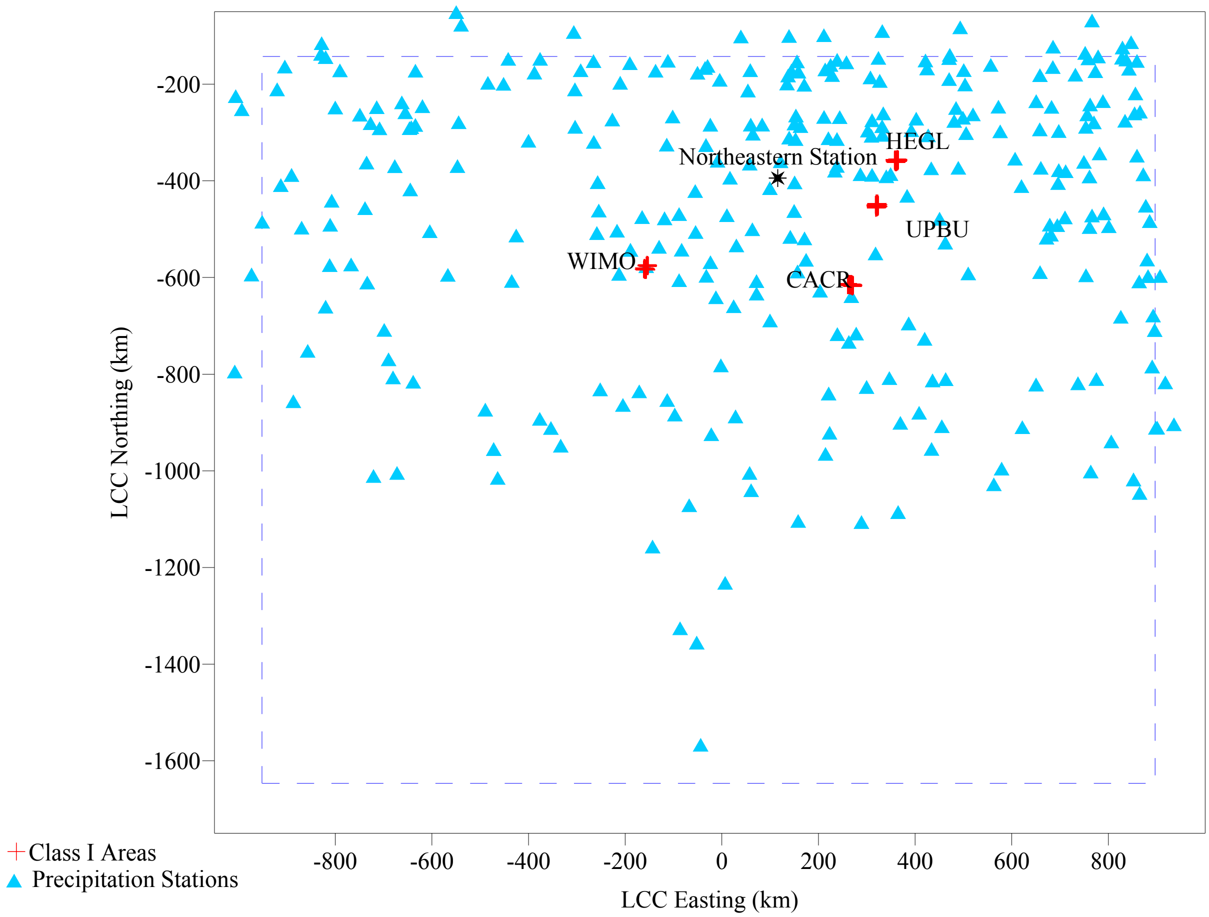
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



3.2.4 PRECIPITATION METEOROLOGICAL DATA

The effects of chemical transformation and deposition processes on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of precipitation in the CALMET analysis. The precipitation stations that are proposed for this analysis are listed in Table A-3 of Appendix A. The locations of the precipitation stations with respect to the modeling domain are shown in Figure 3-5. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain. Data from the stations will be processed for use in CALMET using EPA's PMERGE program.

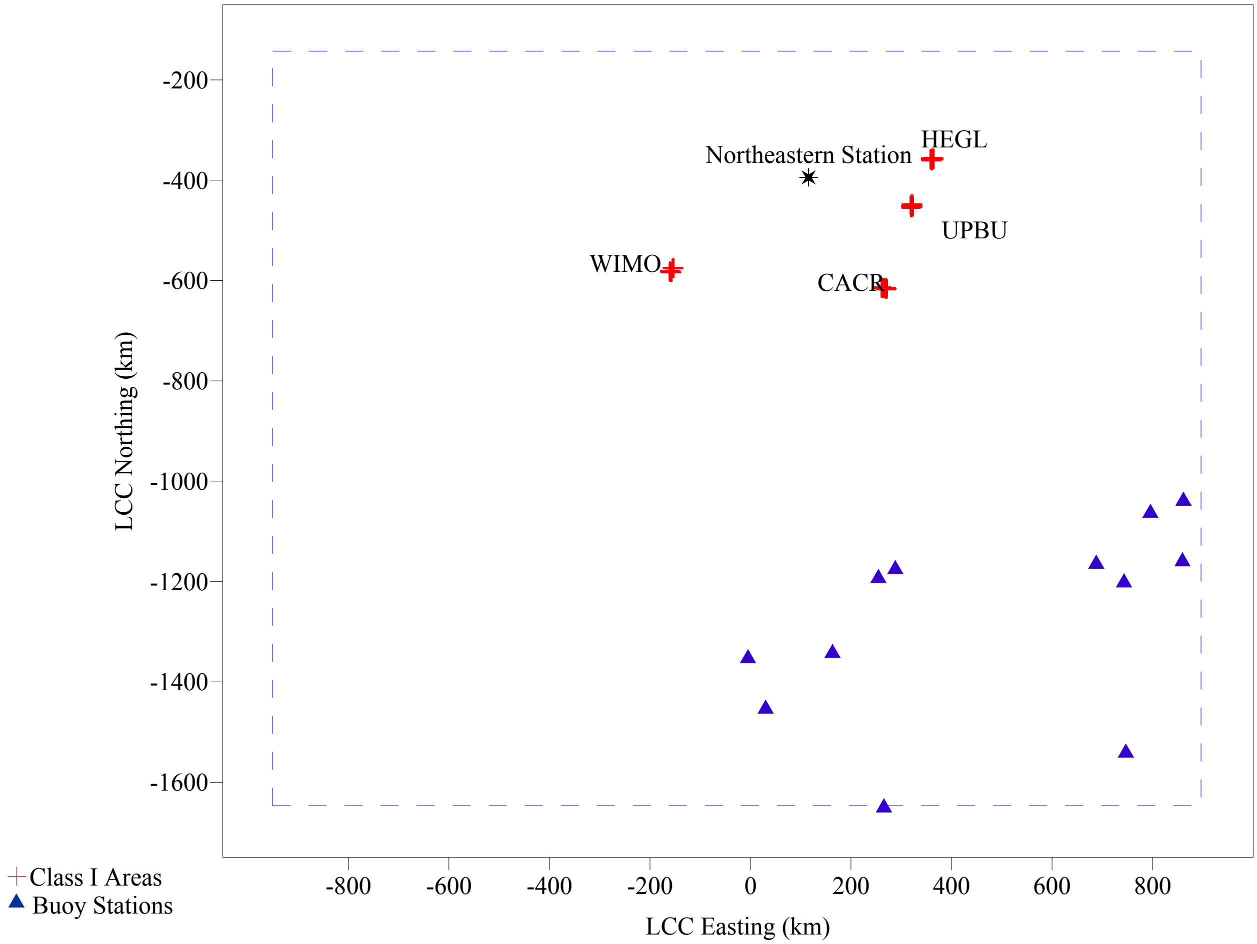
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



3.2.5 BUOY METEOROLOGICAL DATA

The effects of land/sea breeze on ambient pollutant concentrations will be considered in this analysis. Therefore, it is necessary to include observations of buoy stations in the CALMET analysis. The buoy stations that are proposed for this analysis are listed in Table A-4 of Appendix A. The locations of the buoy stations with respect to the modeling domain are shown in Figure 3-6. These stations were selected from the available data inventory to optimize spatial coverage and representation of the domain along the coastline. Data from the stations will be prepared by filling missing hour records with the CALMET missing parameter value (9999). No adjustments to the data will occur.

FIGURE 3-6. PLOT OF BUOY METEOROLOGICAL STATIONS



3.3 CALMET CONTROL PARAMETERS

A few details of the CALMET model setup for sensitive parameters are discussed below.

3.3.1 VERTICAL METEOROLOGICAL PROFILE

The height of the top vertical layer will be set to 3,500 meters. This height corresponds to the top sounding pressure level for which upper air observation data will be relied upon. The vertical dimension of the domain will be divided into 12 layers with the maximum elevations for each layer shown in Table 3-1. The vertical dimensions are weighted towards the surface to resolve the mixing layer while using a somewhat coarser resolution for the layers aloft.

TABLE 3-1. VERTICAL LAYERS OF THE CALMET METEOROLOGICAL DOMAIN

Layer	Elevation (m)
1	20
2	40
3	60
4	80
5	100
6	150
7	200
8	250
9	500
10	1000
11	2000
12	3500

CALMET allows for a bias value to be applied to each of the vertical layers. The bias settings for each vertical layer determine the relative weight given to the vertically extrapolated surface and upper air wind and temperature observations. The initial guess fields are computed with an inverse distance weighting ($1/r^2$) of the surface and upper air data. The initial guess fields may be modified by a layer dependent bias factor. Values for the bias factor may range from -1 to +1. A bias of -1 eliminates upper-air observations in the $1/r^2$ interpolations used to initialize the vertical wind fields. Conversely, a bias of +1 eliminates the surface observations in the interpolations for this layer. Normally, bias is set to zero (0) for each vertical layer, such that the upper air and surface observations are given equal weight in the $1/r^2$ interpolations. The biases for each layer of the proposed modeling domain will be set to zero.

CALMET allows for vertical extrapolation of surface wind observations to layers aloft to be skipped if the surface station is close to the upper air station. Alternatively, CALMET allows data from all surface stations to be extrapolated. The CALMET parameter that controls this setting is IEXTRP. Setting IEXTRP to a value less than zero (0) means that layer 1 data from upper air soundings is ignored in any vertical extrapolations. IEXTRP will be set to -4 for this analysis (i.e., the similarity theory is used to extrapolate the surface winds into the layers aloft, which provides more information on observed local effects to the upper layers).

3.3.2 INFLUENCES OF OBSERVATIONS

Step 1 wind fields will be based on an initial guess using MM5 data and refined to reflect terrain affects. Step 2 wind fields will adjust the Step 1 wind field by incorporating the influence of local observations. An inverse distance method is used to determine the influence of observations to the Step 1 wind field. RMAX1 and RMAX2 define the radius of influence for data from surface stations to land in the surface layer and data from upper air stations to land in the layers aloft. In general, RMAX1 and RMAX2 are used to exclude observations from being inappropriately included in the development of the Step 2 wind field if the distance from an observation station to a grid point exceeds the maximum radius of influence.

If the distance from an observation station to a grid point is less than the value set for RMAX, the observation data will be used in the development of the Step 2 wind field. R1 represents the distance from a surface observation station at which the surface observation and the Step 1 wind field are weighted equally. R2 represents the comparable distance for winds aloft. R1 and R2 are used to weight the observation data with respect to the MM5 data that was used to generate the Step 1 wind field. Large values for R1 and R2 give more weight to the observations, where as small values give more weight to the MM5 data.

In this BART modeling analysis, RMAX 1 will be set to 20 km, and R1 will be set to 10 km. This will limit the influence of the surface observation data from all surface stations to 20 km from each station, and will equally weight the MM5 and observation data at 10 km. RMAX2 will be set to 50 km, and R2 will be set to 25 km. This will limit the influence of the upper air observation data from all surface stations to 50 km from each station, and will equally weight the MM5 and observation data at 25 km. These settings of radius of influence will allow for adequate weighting of the MM5 data and the observation data across the modeling domain due to the vast domain to be modeled. RAMX 3 will be set to 500 km.

4. CALPUFF

The CALPUFF model uses the output file from CALMET together with source, receptor, and chemical reaction information to predict hourly concentration impacts. A three-year CALPUFF analysis will be conducted using data and model settings as described below.

4.1 SOURCE EMISSIONS

Baseline (pre-BART) emission data will be based upon CEMS data collected by AEP over the 2002-2005 timeframe. In accordance with CENRAP guidelines, the emission rate over the highest calendar day (24-hr average) will be used to establish baseline emissions. In addition, the effectiveness of a number of different control technologies for NO_X, and SO_2 will be examined.

4.2 RECEPTOR LOCATIONS

The National Park Service (NPS) has electronic files available on their website that include the discrete locations and elevations of receptors to be evaluated in Class I area analyses. These receptor sets will be used in the CALPUFF model.

4.3 BACKGROUND OZONE AND AMMONIA

Background ozone concentrations are required in order to model the photochemical conversion of SO_2 and NO_X to sulfates (SO_4) and nitrates (NO_3). CALPUFF can use either a single background value representative of an area or hourly ozone data from one or more ozone monitoring stations. Hourly ozone data files will be used in the CALPUFF simulation. As provided by the Oklahoma DEQ, hourly ozone data from the Oklahoma City, Glenpool, and Lawton monitors over the 2001-2003 timeframe will be used. Background concentrations for ammonia will be assumed to be temporally and spatially invariant and will be set to 3 ppb, as described in the CENRAP protocol.

4.4 CALPUFF MODEL CONTROL PARAMETERS

Puff splitting is a generally accepted option in refined modeling analyses over large model domains for assessing impacts on Class I areas; however, this option would require significant computer resources and longer runtime. Based upon previous model runs performed on domains (and restricted computational grids) of the size described in this report, it is expected that runtimes could increase by a factor of 4 to 5 with the inclusion of puff-splitting. Due to this, it is felt that the use of this option will not be necessary to obtain representative concentrations at the individual Class I areas.

5. CALPOST

A three-year CALPOST analysis will be conducted to determine the visibility change in deciview (dv) caused by AEP's BART-eligible sources when compared to a natural background.

5.1 CALPOST – LIGHT EXTINCTION ALGORITHM

The CALPOST visibility processing to be used for this BART analysis is based on the October 2010 guidance from the Federal Land Managers Air Quality Related Values Workgroup (FLAG). The 2010 FLAG guidance, which was issued in draft form on July 8, 2008 and published as final guidance in December 2010, makes technical revisions to the previous guidance issued in December 2000.

Visibility impairment is quantified using the light extinction coefficient (b_{ext}), which is expressed in terms of the haze index expressed in deciviews (dv). The haze index (*HI*) is calculated as follows:

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

The impact of a source is determined by comparing the *HI* attributable to a source relative to estimated natural background conditions. The change in the haze index, in deciviews, also referred to as "delta dv," or Δdv, based on the source and background light extinction is based on the following equation:

$$\Delta\,\mathrm{dv} = 10 * \ln\left[\frac{\mathrm{b}_{\mathrm{ext,\ background}} + \mathrm{b}_{\mathrm{ext,\ source}}}{\mathrm{b}_{\mathrm{ext,\ background}}}\right]$$

The Interagency Monitoring of Protected Visual Environments (IMPROVE) workgroup adopted an equation for predicting light extinction as part of the 2010 FLAG guidance (often referred to as the new IMPROVE equation). The new IMPROVE equation is as follows:

$$b_{ext} = \begin{array}{l} 2.2 f_S(RH)[\mathrm{NH_4(SO_4)_2}]_{\mathrm{Small}} + 4.8 f_L(RH)[\mathrm{NH_4(SO_4)_2}]_{\mathrm{Large}} + \\ 2.4 f_S(RH)[\mathrm{NH_4NO_3}]_{\mathrm{Small}} + 5.1 f_L(RH)[\mathrm{NH_4NO_3}]_{\mathrm{Large}} + \\ 2.8[\mathrm{OC}]_{\mathrm{Small}} + 6.1[\mathrm{OC}]_{\mathrm{Large}} + 10[\mathrm{EC}] + 1[\mathrm{PMF}] + 0.6[\mathrm{PMC}] + \\ 1.4 f_{SS}(RH)[\mathrm{Sea\ Salt}] + b_{\mathrm{Site-specific\ Rayleigh\ Scattering}} + 0.33[\mathrm{NO_2}] \end{array}$$

Visibility impairment predictions for the sources relied upon in this BART analysis will use the equation shown above. The use of this equation is referred to as "Method 8" in the CALPOST control file. The use of Method 8 requires that one of five different "modes" be selected. The modes specify the approach for addressing the growth of hygroscopic particles due to moisture in the atmosphere. "Mode 5" will be used in this BART analysis. Mode 5 addresses moisture in the atmosphere in a similar way as to “Method 6”, where “Method 6” is specified as the preferred approach for use with the old IMPROVE equation in the CENRAP BART modeling protocol.

CALPOST Method 8, Mode 5 requires the following:

- Annual average concentrations reflecting natural background for various particles and for sea salt
- Monthly RH factors for large and small ammonium sulfates and nitrates and for sea salts
- Rayleigh scattering parameter corrected for site-specific elevation

Tables 5-1 to Table 5-4 below show the values for the data described above that will be input to CALPOST for use with Method 8, Mode 5. The values were obtained from the 2010 FLAG guidance.

TABLE 5-1. ANNUAL AVERAGE BACKGROUND CONCENTRATION

Class I Area	$(NH_4)_2SO_4$	NH_4NO_3	OM	EC	Soil	CM	Sea Salt	Rayleigh (Mm^{-1})
Caney Creek Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.03	11
Upper Buffalo Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.03	11
Hercules Glades Wilderness	0.23	0.1	1.8	0.02	0.5	3	0.02	11
Wichita Mountains Wilderness	0.12	0.1	0.6	0.02	0.5	3	0.03	11

TABLE 5-2. F_L(RH) LARGE RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek Wilderness	2.77	2.53	2.37	2.43	2.68	2.71	2.59	2.6	2.71	2.69	2.67	2.79
Upper Buffalo Wilderness	2.71	2.48	2.31	2.33	2.61	2.64	2.57	2.59	2.71	2.58	2.59	2.72
Hercules Glades Wilderness	2.7	2.48	2.3	2.3	2.57	2.59	2.56	2.6	2.69	2.54	2.57	2.72
Wichita Mountains Wilderness	2.39	2.25	2.10	2.11	2.39	2.24	2.02	2.13	2.35	2.22	2.28	2.41

TABLE 5-3. F_S(RH) SMALL RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek Wilderness	3.85	3.44	3.14	3.24	3.66	3.71	3.49	3.51	3.73	3.72	3.68	3.88
Upper Buffalo Wilderness	3.73	3.33	3.03	3.07	3.54	3.57	3.43	3.5	3.71	3.51	3.52	3.74
Hercules Glades Wilderness	3.7	3.33	3.01	3.01	3.47	3.48	3.41	3.51	3.67	3.43	3.46	3.73
Wichita Mountains Wilderness	3.17	2.94	2.69	2.68	3.15	2.86	2.49	2.70	3.07	2.87	2.97	3.20

TABLE 5-4. F_{SS}(RH) SEA SALT RH ADJUSTMENT FACTORS

Class I Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Caney Creek Wilderness	3.9	3.52	3.31	3.41	3.83	3.88	3.69	3.68	3.82	3.76	3.77	3.93
Upper Buffalo Wilderness	3.85	3.47	3.23	3.27	3.72	3.78	3.69	3.7	3.84	3.64	3.67	3.86
Hercules Glades Wilderness	3.86	3.51	3.23	3.22	3.66	3.72	3.69	3.73	3.81	3.57	3.65	3.88
Wichita Mountains Wilderness	3.35	3.12	2.91	2.94	3.40	3.21	2.84	3.01	3.32	3.10	3.20	3.40

5.2 EVALUATING VISIBILITY RESULTS

When evaluating cost-control effectiveness of the various control scenarios, the 98th percentile of the 2001-2003 daily Δdv values output by CALPOST will be examined.

5.3 CALPOST CONTROL PARAMETERS

When a CALPOST input file is created, variable values that differ from the CENRAP protocol will generally be the result of data input/output handling issues (e.g., types of output, receptor numbers, etc.).

TABLE A-1. LIST OF SURFACE METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KDYS	69019	-267.672	-834.095	96.9968	39.9925
2	KNPA	72222	932.565	-1020.909	97.0110	39.9908
3	KBFM	72223	857.471	-996.829	97.0101	39.9910
4	KGZH	72227	946.767	-899.515	97.0112	39.9919
5	KTCL	72228	870.843	-706.104	97.0103	39.9936
6	KNEW	53917	674.172	-1078.342	97.0080	39.9903
7	KNBG	12958	677.719	-1104.227	97.0080	39.9900
8	BVE	12884	741.996	-1153.463	97.0088	39.9896
9	KPTN	72232	550.88	-1124.295	97.0065	39.9898
10	KMEI	13865	774.911	-814.225	97.0092	39.9926
11	KPIB	72234	728.416	-915.165	97.0086	39.9917
12	KGLH	72235	557.072	-703.097	97.0066	39.9936
13	KHEZ	11111	540.777	-912.22	97.0064	39.9918
14	KMCB	11112	622.755	-949.618	97.0074	39.9914
15	KGWO	11113	640.102	-695.286	97.0076	39.9937
16	KASD	72236	692.381	-1043.261	97.0082	39.9906
17	KPOE	72239	363.294	-984.839	97.0043	39.9911
18	KBAZ	72241	-102.133	-1140.886	96.9988	39.9897
19	KGLS	72242	215.108	-1185.604	97.0025	39.9893
20	KDWH	11114	140.413	-1101.174	97.0017	39.9900
21	KIAH	12960	158.266	-1108.37	97.0019	39.9900
22	KHOU	72243	167.147	-1147.402	97.0020	39.9896
23	KEFD	12906	178.551	-1152.782	97.0021	39.9896
24	KCXO	72244	152.739	-1069.309	97.0018	39.9903
25	KCLL	11115	60.898	-1044.381	97.0007	39.9906
26	KLFK	93987	214.643	-969.355	97.0025	39.9912
27	KUTS	11116	136.056	-1026.773	97.0016	39.9907
28	KTYR	11117	150.451	-846.207	97.0018	39.9924
29	KCRS	72246	56.655	-882.642	97.0007	39.9920
30	KGGG	72247	214.572	-841.163	97.0025	39.9924
31	KGKY	11118	-9.365	-812.25	96.9999	39.9927
32	KDTN	72248	304.827	-821.713	97.0036	39.9926
33	KBAD	11119	312.743	-825.101	97.0037	39.9925
34	KMLU	11120	465.834	-816.211	97.0055	39.9926
35	KTVR	11121	561.446	-840.225	97.0066	39.9924
36	KTRL	11122	68.599	-806.417	97.0008	39.9927
37	KOCH	72249	216.81	-930.252	97.0026	39.9916
38	KBRO	12919	-44.167	-1571.387	96.9995	39.9858

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
39	KALI	72251	-103.012	-1363.74	96.9988	39.9877
40	KLRD	12920	-246.548	-1381.603	96.9971	39.9875
41	KSSF	72252	-143.386	-1183.35	96.9983	39.9893
42	KRKP	11123	-4.965	-1324.914	96.9999	39.9880
43	KCOT	11124	-219.097	-1280.964	96.9974	39.9884
44	KLBX	11125	150.245	-1207.466	97.0018	39.9891
45	KSAT	12921	-143.024	-1160.935	96.9983	39.9895
46	KHDO	12962	-211.702	-1178.172	96.9975	39.9894
47	KSKF	72253	-154.625	-1177.555	96.9982	39.9894
48	KHYI	11126	-84.156	-1122.487	96.9990	39.9899
49	KTKI	72254	38.788	-754.791	97.0005	39.9932
50	KBMQ	11127	-118.39	-1027.031	96.9986	39.9907
51	KATT	11128	-67.587	-1075.97	96.9992	39.9903
52	KSGR	11129	131.478	-1151.702	97.0016	39.9896
53	KGTU	11130	-65.624	-1033.173	96.9992	39.9907
54	KVCT	12912	6.587	-1236.788	97.0001	39.9888
55	KPSX	72255	73.878	-1253.33	97.0009	39.9887
56	KACT	13959	-22.12	-929.156	96.9997	39.9916
57	KPWG	72256	-30.147	-944.073	96.9996	39.9915
58	KILE	72257	-65.288	-988.507	96.9992	39.9911
59	KGRK	11131	-79.643	-990.173	96.9991	39.9911
60	KTPL	11132	-38.203	-981.19	96.9996	39.9911
61	KPRX	13960	143.317	-703.663	97.0017	39.9936
62	KDTO	72258	-17.018	-752.974	96.9998	39.9932
63	KAFW	11133	-29.564	-777.061	96.9997	39.9930
64	KFTW	72259	-34.302	-795.502	96.9996	39.9928
65	KMWL	11134	-99.769	-798.767	96.9988	39.9928
66	KRBD	11135	12.453	-810.467	97.0002	39.9927
67	KDRT	11136	-384.069	-1170.59	96.9955	39.9894
68	KFST	22010	-566.418	-988.838	96.9933	39.9911
69	KGDP	72261	-739.127	-873.302	96.9913	39.9921
70	KSJT	72262	-333.338	-952.54	96.9961	39.9914
71	KMRF	23034	-676.265	-1042.616	96.9920	39.9906
72	KMAF	72264	-489.668	-878.107	96.9942	39.9921
73	KINK	23023	-586.882	-890.654	96.9931	39.9920
74	KABI	72265	-252.044	-836.353	96.9970	39.9924
75	KLBB	13962	-445.006	-689.313	96.9948	39.9938
76	KATS	11137	-696.818	-763.258	96.9918	39.9931
77	KCQC	11138	-785.757	-515.724	96.9907	39.9953
78	KROW	23009	-698.822	-712.898	96.9918	39.9936
79	KSRR	72268	-789.593	-686.226	96.9907	39.9938
80	KCNM	11139	-682.79	-822.109	96.9919	39.9926
81	KALM	36870	-838.056	-752.338	96.9901	39.9932
82	KLRU	72269	-931.527	-804.112	96.9890	39.9927

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
83	KTCS	72271	-952.353	-695.469	96.9888	39.9937
84	KSVC	93063	-1042.03	-752.033	96.9877	39.9932
85	KDMN	72272	-1006.77	-799.231	96.9881	39.9928
86	KMSL	72323	854.846	-536.687	97.0101	39.9952
87	KPOF	72330	578.62	-336.733	97.0068	39.9970
88	KGTR	11140	779.065	-689.108	97.0092	39.9938
89	KTUP	93862	753.875	-600.337	97.0089	39.9946
90	KMKL	72334	727.051	-454.383	97.0086	39.9959
91	KLRF	72340	440.654	-550.661	97.0052	39.9950
92	KHKA	11141	643.365	-424.419	97.0076	39.9962
93	KHOT	72341	358.094	-604.603	97.0042	39.9945
94	KTXK	11142	278.022	-720.623	97.0033	39.9935
95	KLLQ	72342	488.655	-698.008	97.0058	39.9937
96	KMWT	72343	254.18	-599.224	97.0030	39.9946
97	KFSM	13964	237.97	-512.87	97.0028	39.9954
98	KSLG	72344	224.881	-419.064	97.0027	39.9962
99	KVBT	11143	248.074	-399.892	97.0029	39.9964
100	KHRO	11144	343.525	-405.601	97.0041	39.9963
101	KFLP	11145	404.239	-399.142	97.0048	39.9964
102	KBVX	11146	480.712	-457.853	97.0057	39.9959
103	KROG	11147	258.44	-397.685	97.0031	39.9964
104	KSPS	13966	-138.053	-664.886	96.9984	39.9940
105	KHBR	72352	-186.121	-551.123	96.9978	39.9950
106	KCSM	11148	-198.844	-513.911	96.9977	39.9954
107	KFDR	11149	-181.653	-625.205	96.9979	39.9944
108	KGOK	72353	-35.905	-458.97	96.9996	39.9959
109	KTIK	72354	-34.581	-506.938	96.9996	39.9954
110	KPWA	11150	-58.596	-493.951	96.9993	39.9955
111	KSWO	11151	-7.42	-425.828	96.9999	39.9962
112	KMKO	72355	146.972	-479.879	97.0017	39.9957
113	KRVS	72356	91.059	-438.276	97.0011	39.9960
114	KBVO	11152	87.136	-357.069	97.0010	39.9968
115	KMLC	11153	110.647	-563.566	97.0013	39.9949
116	KOUN	72357	-40.731	-527.298	96.9995	39.9952
117	KLAW	11154	-129.405	-600.222	96.9985	39.9946
118	KCDS	72360	-300.297	-610.668	96.9965	39.9945
119	KGNT	72362	-985.117	-475.563	96.9884	39.9957
120	KGUP	11155	-1059.48	-427.151	96.9875	39.9961
121	KAMA	23047	-425.319	-518.171	96.9950	39.9953
122	KBGD	72363	-395.603	-466.083	96.9953	39.9958
123	KFMN	72365	-993.449	-297.944	96.9883	39.9973
124	KSKX	72366	-770.464	-355.855	96.9909	39.9968
125	KTCC	23048	-597.271	-511.241	96.9930	39.9954
126	KLVS	23054	-732.565	-448.329	96.9914	39.9960

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
127	KEHR	72423	812.573	-199.695	97.0096	39.9982
128	KEVV	93817	822.929	-172.715	97.0097	39.9984
129	KMVN	72433	704.666	-154.54	97.0083	39.9986
130	KMDH	11156	676.745	-218.041	97.0080	39.9980
131	KBLV	11157	617.659	-136.018	97.0073	39.9988
132	KSUS	3966	547.898	-130.122	97.0065	39.9988
133	KPAH	3816	725.985	-293.319	97.0086	39.9974
134	KJEF	72445	419.01	-145.496	97.0050	39.9987
135	KAIZ	11158	387.096	-200.609	97.0046	39.9982
136	KIXD	72447	182.322	-126.913	97.0022	39.9989
137	KWLD	72450	0	-298.57	97.0000	39.9973
138	KAAO	11159	-18.976	-248.773	96.9998	39.9978
139	KIAB	11160	-23.392	-263.471	96.9997	39.9976
140	KEWK	11161	-24.645	-215.58	96.9997	39.9981
141	KGBD	72451	-161.892	-180.781	96.9981	39.9984
142	KHYS	11162	-195.191	-124.723	96.9977	39.9989
143	KCFV	11163	126.442	-319.698	97.0015	39.9971
144	KFOE	72456	114.618	-115.26	97.0014	39.9990
145	KEHA	72460	-432.761	-320.089	96.9949	39.9971
146	KALS	72462	-777.592	-245.892	96.9908	39.9978
147	KDRO	11164	-945.713	-259.163	96.9888	39.9977
148	KLHX	72463	-568.426	-195.178	96.9933	39.9982
149	KSPD	2128	-494.076	-285.176	96.9942	39.9974
150	KCOS	93037	-664.022	-102.596	96.9922	39.9991
151	KGUC	72467	-857.452	-115.301	96.9899	39.9990
152	KMTJ	93013	-940.981	-109.358	96.9889	39.9990
153	KCEZ	72476	-1020.87	-233.14	96.9880	39.9979
154	KCPS	72531	591.652	-136.14	97.0070	39.9988
155	KLWV	72534	808.939	-94.46	97.0096	39.9992
156	KPPF	74543	130.433	-293.855	97.0015	39.9973
157	KHOP	74671	841.751	-324.569	97.0099	39.9971
158	KBIX	74768	778.252	-1028.514	97.0092	39.9907
159	KPQL	11165	814.599	-1019.583	97.0096	39.9908
160	MMPG	76243	-348.007	-1248.779	96.9959	39.9887
161	MMMV	76342	-446.576	-1449.334	96.9947	39.9869
162	MMMY	76394	-316.664	-1581.176	96.9963	39.9857

TABLE A-2. LIST OF UPPER AIR METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	KABQ	23050	-869.46	-501.713	96.9897	39.9955
2	KAMA	23047	-425.319	-518.171	96.9950	39.9953
3	KBMX	53823	951.609	-702.935	97.0112	39.9936
4	KBNA	13897	920.739	-377.164	97.0109	39.9966
5	KBRO	12919	-44.167	-1571.39	96.9995	39.9858
6	KCRP	12924	-51.535	-1360.35	96.9994	39.9877
7	KDDC	13985	-259.352	-242.681	96.9969	39.9978
8	KDRT	22010	-384.069	-1170.59	96.9955	39.9894
9	KEPZ	3020	-914.558	-852.552	96.9892	39.9923
10	KFWD	3990	-28.034	-793.745	96.9997	39.9928
11	KJAN	3940	650.105	-826.452	97.0077	39.9925
12	KLCH	3937	364.461	-1089.15	97.0043	39.9902
13	KLZK	3952	432.063	-560.441	97.0051	39.9949
14	KMAF	23023	-489.668	-878.107	96.9942	39.9921
15	KOUN	3948	-40.731	-527.298	96.9995	39.9952
16	KSHV	13957	298.869	-831.166	97.0035	39.9925
17	KSIL	53813	698.079	-1054.03	97.0082	39.9905

TABLE A-3. LIST OF PRECIPITATION METEOROLOGICAL STATIONS

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
1	ADDI	10063	906.825	-601.428	97.0107	39.9946
2	ALBE	10140	917.606	-821.64	97.0108	39.9926
3	BERR	10748	892.454	-683.388	97.0105	39.9938
4	HALE	13620	881.928	-601.878	97.0104	39.9946
5	HAMT	13645	863.663	-612.725	97.0102	39.9945
6	JACK	14193	898.014	-915.623	97.0106	39.9917
7	MBLE	15478	851.953	-1022.41	97.0101	39.9908
8	MUSC	15749	880.113	-567.484	97.0104	39.9949
9	PETE	16370	935.558	-908.259	97.0110	39.9918
10	THOM	18178	900.858	-915.326	97.0106	39.9917
11	TUSC	18385	895.631	-713.223	97.0106	39.9936
12	VERN	18517	825.585	-685.773	97.0098	39.9938
13	BEEB	30530	462.394	-532.485	97.0055	39.9952
14	BRIG	30900	318.015	-554.857	97.0038	39.9950
15	CALI	31140	419.619	-731.44	97.0050	39.9934
16	CAMD	31152	386.546	-699.659	97.0046	39.9937
17	DIER	32020	268.114	-643.184	97.0032	39.9942
18	EURE	32356	286.738	-390.862	97.0034	39.9965
19	GILB	32794	383.362	-435.625	97.0045	39.9961
20	GREE	32978	450.594	-483.201	97.0053	39.9956
21	STUT	36920	509.943	-596.328	97.0060	39.9946
22	TEXA	37048	278.022	-720.623	97.0033	39.9935
23	ALAM	50130	-749.044	-267.856	96.9912	39.9976
24	ARAP	50304	-441.903	-152.324	96.9948	39.9986
25	COCH	51713	-819.794	-148.582	96.9903	39.9987
26	CRES	51959	-828.107	-119.911	96.9902	39.9989
27	GRAN	53477	-451.781	-203.82	96.9947	39.9982
28	GUNN	53662	-829.573	-141.995	96.9902	39.9987
29	HUGO	54172	-539.364	-81.948	96.9936	39.9993
30	JOHN	54388	-483.95	-201.915	96.9943	39.9982
31	KIM	54538	-544.501	-283.337	96.9936	39.9974
32	MESA	55531	-993.391	-256.696	96.9883	39.9977
33	ORDW	56136	-549.552	-55.741	96.9935	39.9995
34	OURA	56203	-904.197	-168.246	96.9893	39.9985
35	PLEA	56591	-1005.94	-229.472	96.9881	39.9979
36	PUEB	56740	-633.961	-176.872	96.9925	39.9984
37	TYE	57320	-662.095	-242.254	96.9922	39.9978

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
38	SAGU	57337	-790.269	-176.061	96.9907	39.9984
39	SANL	57428	-726.777	-285.47	96.9914	39.9974
40	SHEP	57572	-714.046	-252.189	96.9916	39.9977
41	TELL	58204	-920.205	-215.382	96.9891	39.9981
42	TERC	58220	-708.229	-296.023	96.9916	39.9973
43	TRIN	58429	-642.489	-293.805	96.9924	39.9973
44	TRLK	58436	-646.185	-295.727	96.9924	39.9973
45	WALS	58781	-654.989	-262.821	96.9923	39.9976
46	WHIT	58997	-619.615	-250.12	96.9927	39.9977
47	ASHL	110281	684.787	-169.285	97.0081	39.9985
48	CAIR	111166	697.177	-301.436	97.0082	39.9973
49	CARM	111302	772.938	-177.782	97.0091	39.9984
50	CISN	111664	758.146	-151.446	97.0090	39.9986
51	FLOR	113109	751.801	-139.837	97.0089	39.9987
52	HARR	113879	762.044	-246.62	97.0090	39.9978
53	KASK	114629	650.464	-239.886	97.0077	39.9978
54	LAWR	114957	829.038	-128.708	97.0098	39.9988
55	MTCA	115888	827.797	-149.966	97.0098	39.9986
56	MURP	115983	682.261	-251.649	97.0081	39.9977
57	NEWT	116159	766.098	-72.902	97.0090	39.9993
58	REND	117187	731.633	-185.058	97.0086	39.9983
59	SMIT	118020	770.027	-283.638	97.0091	39.9974
60	SPAR	118147	658.275	-185.973	97.0078	39.9983
61	VAND	118781	685.449	-127.048	97.0081	39.9989
62	WEST	119193	778.655	-147.215	97.0092	39.9987
63	EVAN	122738	842.476	-172.871	97.0100	39.9984
64	NEWB	126151	855.854	-223.713	97.0101	39.9980
65	PRIN	127125	836.901	-153.449	97.0099	39.9986
66	STEN	128442	859.099	-156.613	97.0101	39.9986
67	JTML	128967	788.703	-239.572	97.0093	39.9978
68	ARLI	140326	-101.734	-271.373	96.9988	39.9976
69	BAZI	140620	-210.423	-201.758	96.9975	39.9982
70	BEAU	140637	59.762	-288.39	97.0007	39.9974
71	BONN	140957	211.236	-103.29	97.0025	39.9991
72	CALD	141233	-32.689	-330.586	96.9996	39.9970
73	CASS	141351	54.006	-217.645	97.0006	39.9980
74	CENT	141404	170.503	-206.038	97.0020	39.9981
75	CHAN	141427	150.257	-286.094	97.0018	39.9974
76	CLIN	141612	155.623	-157.682	97.0018	39.9986
77	COLL	141730	-265.465	-156.95	96.9969	39.9986

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
78	COLU	141740	220.541	-316.555	97.0026	39.9971
79	CONC	141867	58.918	-175.589	97.0007	39.9984
80	DODG	142164	-226.497	-277.655	96.9973	39.9975
81	ELKH	142432	-400.112	-321.784	96.9953	39.9971
82	ENGL	142560	-264.927	-324.066	96.9969	39.9971
83	ERIE	142582	162.669	-291.383	97.0019	39.9974
84	FALL	142686	83.491	-288.177	97.0010	39.9974
85	GALA	142938	-136.931	-176.83	96.9984	39.9984
86	GARD	142980	-304.059	-215.308	96.9964	39.9981
87	GREN	143248	64.308	-307.161	97.0008	39.9972
88	HAYS	143527	-190.307	-161.342	96.9978	39.9985
89	HEAL	143554	-292.133	-175.921	96.9966	39.9984
90	HILL	143686	214.018	-174.006	97.0025	39.9984
91	INDE	143954	139.335	-315.058	97.0016	39.9972
92	IOLA	143984	153.451	-269.438	97.0018	39.9976
93	JOHR	144104	134.784	-203.41	97.0016	39.9982
94	KANO	144178	-50.289	-181.177	96.9994	39.9984
95	KIOW	144341	-113.967	-329.843	96.9987	39.9970
96	MARI	145039	-4.343	-195.712	97.0000	39.9982
97	MELV	145210	137.104	-186.781	97.0016	39.9983
98	MILF	145306	39.504	-106.05	97.0005	39.9990
99	MOUD	145536	152.624	-318.136	97.0018	39.9971
100	OAKL	145888	-306.378	-96.814	96.9964	39.9991
101	OTTA	146128	158.639	-178.635	97.0019	39.9984
102	POMO	146498	143.864	-176.707	97.0017	39.9984
103	SALI	147160	-29.426	-166.908	96.9997	39.9985
104	SMOL	147551	-34.639	-171.31	96.9996	39.9985
105	STAN	147756	225.026	-164.85	97.0027	39.9985
106	SUBL	147922	-303.514	-292.808	96.9964	39.9974
107	TOPE	148167	139.116	-104.91	97.0016	39.9991
108	TRIB	148235	-387.855	-180.643	96.9954	39.9984
109	UNIO	148293	211.43	-272.537	97.0025	39.9975
110	WALL	148535	-376.076	-152.432	96.9956	39.9986
111	WICH	148830	-23.729	-288.579	96.9997	39.9974
112	WILS	148946	-111.502	-156.22	96.9987	39.9986
113	BENT	150611	781.608	-348.109	97.0092	39.9969
114	CALH	151227	865.268	-261.635	97.0102	39.9976
115	CLTN	151631	749.287	-365.634	97.0088	39.9967
116	HERN	153798	859.01	-352.458	97.0101	39.9968
117	MADI	155067	854.116	-265.064	97.0101	39.9976

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
118	PADU	156110	753.185	-293.024	97.0089	39.9974
119	PCTN	156580	834.464	-280.496	97.0099	39.9975
120	ALEX	160103	433.824	-959.253	97.0051	39.9913
121	BATN	160549	562.794	-1032.4	97.0066	39.9907
122	CALH	161411	436.113	-817.451	97.0052	39.9926
123	CLNT	161899	578.969	-999.986	97.0068	39.9910
124	JENA	164696	455.225	-912.366	97.0054	39.9918
125	LACM	165078	364.784	-1089.92	97.0043	39.9901
126	MIND	166244	346.708	-812.651	97.0041	39.9927
127	MONR	166314	463.225	-814.905	97.0055	39.9926
128	NATC	166582	369.451	-905.316	97.0044	39.9918
129	SHRE	168440	299.526	-831.143	97.0035	39.9925
130	WINN	169803	408.309	-884.596	97.0048	39.9920
131	BROK	221094	621.827	-914.236	97.0073	39.9917
132	CONE	221900	737.007	-823.513	97.0087	39.9926
133	JAKS	224472	650.361	-826.097	97.0077	39.9925
134	LEAK	224966	805.886	-943.78	97.0095	39.9915
135	MERI	225776	774.942	-814.558	97.0092	39.9926
136	SARD	227815	658.33	-593.661	97.0078	39.9946
137	SAUC	227840	763.399	-1005.93	97.0090	39.9909
138	TUPE	229003	753.571	-600.03	97.0089	39.9946
139	ADVA	230022	657.892	-298.102	97.0078	39.9973
140	ALEY	230088	505.348	-305.864	97.0060	39.9972
141	BOLI	230789	331.651	-291.689	97.0039	39.9974
142	CASV	231383	310.855	-392.187	97.0037	39.9965
143	CLER	231674	575.868	-302.209	97.0068	39.9973
144	CLTT	231711	307.465	-190.83	97.0036	39.9983
145	COLU	231791	421.287	-155.672	97.0050	39.9986
146	DREX	232331	228.23	-185.776	97.0027	39.9983
147	ELM	232568	257.758	-159.419	97.0030	39.9986
148	FULT	233079	470.408	-150.668	97.0056	39.9986
149	HOME	233999	619.93	-415.469	97.0073	39.9962
150	JEFF	234271	424.774	-172.095	97.0050	39.9984
151	JOPL	234315	238.245	-318.262	97.0028	39.9971
152	LEBA	234825	402.239	-276.263	97.0048	39.9975
153	LICK	234919	480.849	-280.775	97.0057	39.9975
154	LOCK	235027	302.048	-300.612	97.0036	39.9973
155	MALD	235207	659.982	-377.876	97.0078	39.9966
156	MARS	235298	332.062	-94.655	97.0039	39.9991
157	MAFD	235307	391.968	-300.033	97.0046	39.9973

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
158	MCES	235415	471.737	-143.942	97.0056	39.9987
159	MILL	235594	309.516	-311.398	97.0037	39.9972
160	MTGV	235834	426.937	-310.43	97.0050	39.9972
161	NVAD	235987	243.915	-272.715	97.0029	39.9975
162	OZRK	236460	349.133	-390.626	97.0041	39.9965
163	PDTD	236777	334.055	-265.018	97.0039	39.9976
164	POTO	236826	572.215	-251.455	97.0068	39.9977
165	ROLL	237263	484.503	-253.958	97.0057	39.9977
166	ROSE	237300	500.59	-175.393	97.0059	39.9984
167	SALE	237506	498.94	-274.122	97.0059	39.9975
168	SENE	237656	233.959	-383.703	97.0028	39.9965
169	SPRC	237967	238.112	-373.616	97.0028	39.9966
170	SPVL	237976	332.385	-309.374	97.0039	39.9972
171	STEE	238043	503.354	-205.135	97.0059	39.9981
172	STOK	238082	310.911	-279.239	97.0037	39.9975
173	SWSP	238223	324.053	-150.325	97.0038	39.9986
174	TRKD	238252	340.418	-395.428	97.0040	39.9964
175	TRUM	238466	326.883	-197.796	97.0039	39.9982
176	UNIT	238524	238.567	-154.494	97.0028	39.9986
177	VIBU	238609	519.633	-267.258	97.0061	39.9976
178	VIEN	238620	470.383	-193.872	97.0056	39.9983
179	WAPP	238700	606.68	-358.746	97.0072	39.9968
180	WASG	238746	556.425	-164.993	97.0066	39.9985
181	WEST	238880	489.373	-377.809	97.0058	39.9966
182	ALBU	290234	-869.46	-501.713	96.9897	39.9955
183	ARTE	290600	-689.529	-773.897	96.9919	39.9930
184	AUGU	290640	-973.07	-598.391	96.9885	39.9946
185	CARL	291469	-680.335	-811.474	96.9920	39.9927
186	CARR	291515	-819.836	-665.132	96.9903	39.9940
187	CLAY	291887	-547.124	-374.102	96.9935	39.9966
188	CLOV	291939	-566.973	-599.296	96.9933	39.9946
189	CUBA	292241	-890.304	-392.495	96.9895	39.9965
190	CUBE	292250	-951.142	-489.293	96.9888	39.9956
191	DEMI	292436	-1007.99	-799.087	96.9881	39.9928
192	DURA	292665	-767.148	-577.618	96.9909	39.9948
193	EANT	292700	-735.089	-366.94	96.9913	39.9967
194	LAVG	294862	-738.245	-461.163	96.9913	39.9958
195	PROG	297094	-811.39	-578.971	96.9904	39.9948
196	RAMO	297254	-733.737	-615.175	96.9913	39.9944
197	ROSW	297610	-698.544	-712.921	96.9918	39.9936

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
198	ROY	297638	-644.735	-422.422	96.9924	39.9962
199	SANT	298085	-807.375	-445.708	96.9905	39.9960
200	SPRI	298501	-676.681	-374.272	96.9920	39.9966
201	STAY	298518	-810.491	-495.501	96.9904	39.9955
202	TNMN	299031	-912.488	-413.425	96.9892	39.9963
203	TUCU	299156	-604.359	-508.834	96.9929	39.9954
204	WAST	299569	-638.605	-820.288	96.9925	39.9926
205	WISD	299686	-856.967	-756.366	96.9899	39.9932
206	AIRS	340179	-212.731	-597.062	96.9975	39.9946
207	ARDM	340292	-12.242	-645.633	96.9999	39.9942
208	BENG	340670	174.368	-568.011	97.0021	39.9949
209	CANE	341437	71.857	-637.935	97.0009	39.9942
210	CHRT	341544	203.233	-632.067	97.0024	39.9943
211	CHAN	341684	10.494	-475.655	97.0001	39.9957
212	CHIK	341750	-83.175	-547.26	96.9990	39.9951
213	CCTY	342334	-165	-479.536	96.9981	39.9957
214	DUNC	342654	-88.38	-610.04	96.9990	39.9945
215	ELKC	342849	-216.769	-507.879	96.9974	39.9954
216	FORT	343281	-129.964	-541.113	96.9985	39.9951
217	GEAR	343497	-118.53	-482.187	96.9986	39.9956
218	HENN	344052	-31.964	-601.206	96.9996	39.9946
219	HOBA	344202	-189.062	-547.36	96.9978	39.9951
220	KING	344865	24.538	-664.103	97.0003	39.9940
221	LKEU	344975	141.702	-520.6	97.0017	39.9953
222	LEHI	345108	71.634	-612.05	97.0009	39.9945
223	MACI	345463	-254.63	-466.154	96.9970	39.9958
224	MALL	345589	-55.127	-425.644	96.9994	39.9962
225	MAYF	345648	-258.49	-512.583	96.9970	39.9954
226	MUSK	346130	149.764	-466.905	97.0018	39.9958
227	NOWA	346485	121.551	-364.038	97.0014	39.9967
228	OKAR	346620	-88.424	-473.338	96.9990	39.9957
229	OKEM	346638	63.188	-504.958	97.0008	39.9954
230	OKLA	346661	-54.198	-510.562	96.9994	39.9954
231	PAOL	346859	-23.665	-573.142	96.9997	39.9948
232	PAWH	346935	57.704	-369.174	97.0007	39.9967
233	PAWN	346944	16.927	-398.139	97.0002	39.9964
234	PONC	347196	-8.871	-363.068	96.9999	39.9967
235	PRYO	347309	150.763	-407.824	97.0018	39.9963
236	SHAT	348101	-256.963	-407.368	96.9970	39.9963
237	STIG	348497	171.02	-523.736	97.0020	39.9953

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
238	TULS	348992	99.361	-419.873	97.0012	39.9962
239	TUSK	349023	156.629	-592.395	97.0019	39.9946
240	WMWR	349629	-156.42	-581.308	96.9982	39.9947
241	WOLF	349748	30.212	-538.388	97.0004	39.9951
242	BOLI	400876	760.886	-500.256	97.0090	39.9955
243	BROW	401150	710.048	-480.346	97.0084	39.9957
244	CETR	401587	877.35	-456.294	97.0104	39.9959
245	DICS	402489	872.14	-391.132	97.0103	39.9965
246	DYER	402680	695.792	-409.316	97.0082	39.9963
247	GRNF	403697	760.795	-395.69	97.0090	39.9964
248	JSNN	404561	765.932	-476.414	97.0090	39.9957
249	LWER	405089	885.291	-487.757	97.0105	39.9956
250	LEXI	405210	790.003	-471.897	97.0093	39.9957
251	MASO	405720	694.163	-496.166	97.0082	39.9955
252	MEMP	405954	671.8	-522.492	97.0079	39.9953
253	MWFO	405956	681.292	-516.15	97.0080	39.9953
254	MUNF	406358	678.65	-495.241	97.0080	39.9955
255	SAMB	408065	697.077	-382.536	97.0082	39.9965
256	SAVA	408108	800.788	-498.682	97.0095	39.9955
257	UNCY	409219	711.595	-384.605	97.0084	39.9965
258	ABIL	410016	-251.753	-836.027	96.9970	39.9924
259	AMAR	410211	-425.302	-517.839	96.9950	39.9953
260	AUST	410428	-67.587	-1075.97	96.9992	39.9903
261	BRWN	411136	-43.861	-1571.39	96.9995	39.9858
262	COST	411889	60.611	-1044.72	97.0007	39.9906
263	COCR	412015	-51.832	-1360.01	96.9994	39.9877
264	CROS	412131	-204.599	-868.469	96.9976	39.9922
265	DFWT	412242	-1.867	-786.341	97.0000	39.9929
266	EAST	412715	-171.024	-840.253	96.9980	39.9924
267	ELPA	412797	-886.583	-860.763	96.9895	39.9922
268	HICO	414137	-97.323	-888.181	96.9989	39.9920
269	HUST	414300	157.976	-1108.38	97.0019	39.9900
270	KRES	414880	-434.746	-611.717	96.9949	39.9945
271	LKCK	414975	99.734	-693.521	97.0012	39.9937
272	LNGV	415348	220.962	-844.674	97.0026	39.9924
273	LUFK	415424	214.652	-969.69	97.0025	39.9912
274	MATH	415661	-86.438	-1330.47	96.9990	39.9880
275	MIDR	415890	-489.385	-878.123	96.9942	39.9921
276	MTLK	416104	-672.024	-1008.98	96.9921	39.9909
277	NACO	416177	223.065	-925.966	97.0026	39.9916

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
278	NAVA	416210	28.358	-892.028	97.0003	39.9919
279	NEWB	416270	239.111	-721.818	97.0028	39.9935
280	BPAT	417174	288.962	-1110.65	97.0034	39.9900
281	RANK	417431	-472.048	-959.488	96.9944	39.9913
282	SAAG	417943	-333.338	-952.54	96.9961	39.9914
283	SAAT	417945	-143.322	-1161.27	96.9983	39.9895
284	SHEF	418252	-463.759	-1019.19	96.9945	39.9908
285	STEP	418623	-112.988	-857.918	96.9987	39.9922
286	STER	418630	-376.683	-897.195	96.9956	39.9919
287	VALE	419270	-720.749	-1015.17	96.9915	39.9908
288	VICT	419364	6.882	-1236.45	97.0001	39.9888
289	WACO	419419	-21.834	-928.823	96.9997	39.9916
290	WATR	419499	-353.767	-916.015	96.9958	39.9917
291	WHEE	419665	57.489	-1008.99	97.0007	39.9909
292	WPDM	419916	262.792	-737.786	97.0031	39.9933
293	DORA	232302	433.256	-378.797	97.0051	39.9966
294	DIXN	112353	756.057	-267.193	97.0089	39.9976
295	DAUP	12172	864.408	-1050.41	97.0102	39.9905
296	FREV	123104	847.031	-117.884	97.0100	39.9989
297	WARR	18673	890.447	-788.703	97.0105	39.9929
298	MDTN	235562	493.264	-87.222	97.0058	39.9992

TABLE A-4. LIST OF OVER WATER METEOROLOGICAL STATIONS

Number	Station ID	Input file Name	LCC East (km)	LCC North (km)	Long	Lat
1	42001	42001	746.874	-1541.35	89.67	25.9
2	42002	42002	265.486	-1650.616	94.42	25.19
3	42007	42007	795.674	-1063.667	88.77	30.09
4	42019	42019	163.178	-1342.917	95.36	27.91
5	42020	42020	30.212	-1453.738	96.7	26.94
6	42035	42035	254.465	-1193.539	94.41	29.25
7	42040	42040	859.497	-1160.066	88.21	29.18
8	BURL1	42045	743.116	-1202.117	89.43	28.9
9	DPIA1	42046	861.385	-1039.466	88.07	30.25
10	GDIL1	42047	687.984	-1164.910	89.96	29.27
11	PTAT2	42048	-4.980	-1353.398	97.05	27.83
12	SRST2	42049	288.163	-1175.682	94.05	29.67

NE3 DSI-ACI-FF

Budgetary Cost Estimate Breakdown (Class 4)

WBS	Description	DSI	ACI	FF	By-Product Handling	BOP	Contingency	Total
010	Existing Conditions					$ 371,702		$ 371,702
110	Site Development					$ 7,731,298		$ 7,731,298
140	Rail Improvements	$ 3,449,477						$ 3,449,477
222	Chiller/Dehumidifier Building	$ 200,527	$ 200,526					$ 401,053
253	ACI/DSI/Byproduct Electical PDC Building	$ 174,590	$ 174,590		$ 174,590			$ 523,770
254	FF Switchgear & Control (PDC) Building			$ 2,982,830				$ 2,982,830
255	DSI/ACI Blower Building	$ 413,150	$ 413,150					$ 826,300
256	Air Compressor/ByProduct Blower Building				$ 1,066,339			$ 1,066,339
415	Booster Fan			$ 4,787,003				$ 4,787,003
416	Flue Gas Duct			$ 13,203,070				$ 13,203,070
442	ACI Unloading & Storage		$ 4,686,279					$ 4,686,279
444	ACI Feed & Injection		$ 846,019					$ 846,019
445	DSI Unloading & Storage	$ 16,080,123						$ 16,080,123
446	Dry Sorbent Injection (DSI)	$ 969,973						$ 969,973
456	Fabric Filter (FF)			$ 33,657,710				$ 33,657,710
484	Fly Ash Extraction System				$ 136,006			$ 136,006
492	Byproduct Handling System				$ 13,529,030			$ 13,529,030
605	Common Utility Racks					$ 1,214,175		$ 1,214,175
612	Plant Air					$ 1,316,703		$ 1,316,703
614	Instrument Air					$ 2,431,495		$ 2,431,495
624	Service Water					$ 831,508		$ 831,508
626	Potable Water					$ 157,324		$ 157,324
632	Process Water Drain					$ 240,327		$ 240,327
634	Storm Sewer					$ 692,336		$ 692,336
730	Medium Voltage Electric (1000V - 15 kV)			$ 1,959,632				$ 1,959,632
740	Low Voltage	$ 945,893	$ 280,845	$ 2,514,501	$ 662,324	$ 665,918		$ 5,069,480
860	Construction Indirects	$ 841,492	$ 249,847	$ 2,236,969	$ 589,221	$ 592,419		$ 4,509,948
901	Outside Professional Services	$ 112,236	$ 33,324	$ 298,361	$ 78,589	$ 79,015		$ 601,525
912	Conceptual Engineering	$ 497,466	$ 147,702	$ 1,322,433	$ 348,331	$ 350,222		$ 2,666,154
913	Detailed Design Engineering	$ 1,554,259	$ 461,474	$ 4,131,744	$ 1,088,308	$ 1,094,215		$ 8,330,000
920	Project Management & Controls	$ 1,709,125	$ 507,456	$ 4,543,430	$ 1,196,747	$ 1,203,242		$ 9,160,000
970	AEP Services	$ 2,954,457	$ 877,207	$ 7,853,942	$ 2,068,742	$ 2,079,970		$ 15,834,318
980	Contingency						$ 14,737,092	$ 14,737,092
		$ 29,902,768	$ 8,878,419	$ 79,491,624	$ 20,938,227	$ 21,051,870	$ 14,737,092	$ 175,000,000