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AR-12-078

October 14, 2013

Mr. Mike Bates
Chief, Air Division
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118

RE: Entergy Arkansas, Inc. – White Bluff Plant
Revised BART Five-Factor Analysis
Permit No. 0263-AOP-R7, AFIN 35-00110

Dear Mr. Bates:

Please find attached a revised and updated Best Available Retrofit Technology (BART) Five-Factor Analysis (FFA) for the Entergy Arkansas, Inc – White Bluff Plant. This updated FFA was completed in order to incorporate revisions made to the analysis in response to questions received from EPA Region 6 staff regarding the revised FFA which was submitted on June 10, 2013.

In addition to the revised FFA document, we have enclosed a question and answer document in which we directly respond to each specific issue raised in EPA's comments.

We appreciate ADEQ's consideration of this analysis and additional supporting information. Should you or your staff have any questions regarding this submittal, please contact me at (501) 377-4033 or David Triplett at (501) 377-4030.

Sincerely,

G. Tracy Johnson

G. Tracy Johnson
Manager, Arkansas Environmental Support

GTJ/dct

CC: Mary Pettyjohn, ADEQ (via email)

Entergy Response to 8/21/2013 EPA Region 6 comments on the White Bluff BART FFA

Entergy has reviewed the comments provided by EPA Region 6 on August 21, 2013, and appreciates the opportunity to provide the below response. To simplify the format of this response, we have included each of EPA's comments, followed by our response. Submitted concurrently herewith is a revised Five-Factor Analysis (FFA) incorporating several revisions as discussed below.

NOx BART

- **EPA Comment 1** - The 2012 S&L NOx Study identifies neural net system upgrades as a potential NOx control. However, this control option is not evaluated by Entergy in the BART analysis for Units 1 and 2. While it appears that the added visibility benefit of LNB/SOFA + SNCR compared to LNB/SOFA is too small to justify the added cost of installing SNCR, we believe the added cost of LNB/SOFA + Neural Net System Upgrades compared to LNB/SOFA would likely be small and may provide some visibility benefit. ADEQ should ensure that if a NOx emission limit more stringent than 0.15 lb/MMBtu could be expected from LNB/SOFA + Neural Net System Upgrades, this should be evaluated as a separate control option in the BART analysis.

  Entergy Response – Entergy does not believe that operation of neural network system upgrades in conjunction with LNB/SOFA would result in a NOx emission limit more stringent than the 0.15 lb/MMBtu proposed in the FFA. The information[1] presented in the S&L NOx study regarding neural network system upgrades was an estimate of the level of NOx reductions which could potentially be achieved through implementation of neural network system upgrades for the White Bluff units as currently configured (without LNB/SOFA). As no vendor guarantees were available for the NOx performance of such neural network system upgrades, and the level of NOx emission reduction estimated by S&L from the operation of neural network system upgrades alone (10%) was significantly less than the potential NOx emission reductions achievable by other evaluated control technologies, no consideration was given to this option in the FFA.

  Since receiving this question from EPA, Entergy has conducted additional discussions with S&L regarding the potential for neural network system upgrades to be operated in conjunction with LNB/SOFA to achieve additional levels of NOx control beyond that expected from LNB/SOFA alone. S&L provided the following statement on this subject.

  > The Neural Network (NN) is a computer program that evaluates controllable parameters affecting the NOx emission rate from the boiler and learns over a long period of operation (years) how to minimize the NOx emission rate. The suppliers of NN do not

[1] Percent NOx emission reduction and expected NOx emission rates

offer a guarantee on NOx emission rate or percent reduction. The primary benefit is to maintain over time the guaranteed NOx emission rate performance resulting from LNB/SOFA. There are NN installations that have achieved small improvements in NOx emission rate over a long period of time but as previously stated, the NN suppliers aren't offering guarantees and the NN may take many years to realize the performance improvement. While this combination of technologies may be desirable in the long run, we don't recommend it as a separate NOx control option to be evaluated in the BART analysis.

Based on the lack of a NOx emission reduction guarantee, Entergy does not believe that the combination of NN system upgrades with LNB/SOFA should be evaluated as a separate, distinct control option within the FFA.

Cost Analysis for SO_2 and NO_x Controls

- **EPA Comment 2** - We are not providing an exhaustive line-by-line review of costs for SO2 and NOx controls because we do not anticipate that further revisions to the cost numbers would change the ultimate BART determinations. However, we wish to make clear that EPA disagrees that the Control Cost Manual (CCM) allows for AFUDC to be included in the BART cost evaluation. AFUDC is the cost of capital that is incurred to finance the project during the construction period. While AFUDC is a valid cost under the all-in cost estimating methodology, it is not a valid cost under the CCM methodology. The Regional Haze Rule states the CCM should be followed where possible, and the CCM uses overnight costing methodology. The overnight cost method is the cost of a construction project if no interest is incurred during construction, as if the project is completed overnight. Thus, AFUDC is never valid under the CCM overnight cost approach. ADEQ should ensure that the cost estimates for all SO2 and NOx controls are revised to exclude AFUDC in order to reflect an accurate estimate of cost-effectiveness of controls.

Entergy Response – Entergy continues to believe that the overnight costing methodology advocated by EPA represents an overly simplistic view of the true costs associated with a significant pollution control project such as those evaluated by Entergy in this FFA. AFUDC represents the interest expense on the investment in the technology that is incurred during construction, before the equipment is placed in service. For major control technology installations, such as scrubbers or SCR, the interest expense incurred during the 30 - 46 months of construction can reach \$30 million to \$60 million for a large unit. AFUDC simply includes the interest as part of the capital cost, which is standard accounting and rate-making treatment of such costs.

Entergy does not agree that the CCM requires the company to exclude AFUDC from control technology costs. Nonetheless, although Entergy is not waiving its ability to include AFUDC in future control cost analyses, to expedite ADEQ's consideration of the FFA for White Bluff, we have revised the FFA document to remove AFUDC from the costs of each evaluated pollution control technology as requested by EPA staff. While this change lowers the overall capital costs presented within the latest FFA, the BART determinations for each affected pollutant (SO_2 and NO_x) remain unchanged.

Auxiliary Boiler (SN-05)

- **EPA Comment 3** - The calculations provided indicate that average sulfur content over the 2009-2011 period and the average heat content over this same period were utilized to estimate the modeled emission rate. The use of average values based on a three year average of annual values is inconsistent with estimating the maximum 24-hr emission rate from the baseline period. Please provide additional information on the variability of sulfur content and heat content in order to estimate the range of the maximum impact.

Entergy Response – Entergy reviewed the monthly fuel oil sampling data for the facility along with daily records of aux. boiler hours of operation for 2009-2011. Over the 2009-2011 period, the heat content of the fuel oil ranged from 134,318 btu/gal to 142,422 btu/gal, and the sulfur content ranged from 0.004% to 0.056%[2]. By combining each month's fuel sampling result for heat and oil sulfur content with the maximum daily hours of operation for the aux. boiler for the month, it is possible to produce a refined estimate of the maximum daily (24-hour) average SO_2 emission rate from this unit.

Based on this data, the maximum 24-hour average SO_2 emission rate occurred on May 10, 2009. The monthly fuel analysis for May 2009 indicates a heat content of 135,438 btu/gal (135.438 MMBtu/Mgal) and a sulfur content of 0.0441% by weight. Based on the emission factor presented in AP-42 Table 1.3-1 for distillate fuel-fired boilers of >100 MMBtu/hr (142S lb/Mgal), the SO_2 emission factor for May 2009 is calculated as 0.0462 lb/MMBtu. At the maximum 24-hour average heat input rate for May 2009 of 121.23 MMBtu/hr[3], the maximum 24-hour average SO_2 emission rate for the 2009-2011 period is calculated as 5.61 lb/hr.

This refined estimate of the maximum baseline 24-hour SO_2 emission rate for the aux. boiler is less than the rate (5.8 lb/hr) which was utilized to estimate the baseline visibility impairment

[2] Entergy notes that the sulfur content of the No. 2 fuel oil used at White Bluff has trended downward over time, with the annual average sulfur content for 2011 being 0.013% and the average for 2012 being 0.0042%. Due to the increasing restrictions on the sulfur content of commercially available No. 2 fuel oil, it is unlikely that the sulfur content in future years will return to past levels.

[3] This rate was calculated based on the maximum daily hours of operation in May of 2009 (15.9 hours on May 10) and the maximum heat input capacity of the aux. boiler (183 MMBtu/hr). This calculation assumes that the aux. boiler was operating at the maximum rated capacity at all times that it was online on this date. This assumption results in an over-estimate of the actual average heat input for this date.

attributable to this unit. As such, the analysis presented within the FFA is conservative and no refinement to the modeled SO_2 emission rate for the aux. boiler is necessary.

- **EPA Comment 4** - The rationale for determining that no additional controls are required for this unit differs in the revised BART report and the response to Region 6 comments you provided (comment 16). Please revise the BART report to be consistent with your response to our comments, as the response provides an appropriate justification for no additional controls at the auxiliary boiler.

Entergy Response – The BART FFA report has been revised to include the rationale for determining that no additional controls are required for the auxiliary boiler which was presented in the June 2013 response to comments document.

REVISED BART FIVE FACTOR ANALYSIS

WHITE BLUFF STEAM ELECTRIC STATION

REDFIELD, ARKANSAS (AFIN 35-00110)

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Trinity Project No. 123701.0053

October 2013

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1. EXECUTIVE SUMMARY

This report is a revision to "BART Five Factor Analysis" submitted to ADEQ on February 21, 2013, and revised and resubmitted on June 10, 2013. This report is submitted to provide a comprehensive document that encompasses the determination of the Best Available Retrofit Technology (BART) for Entergy Arkansas, Inc.'s (Entergy's) BART-affected electric generating units (EGUs) at the White Bluff including changes made in response to EPA's comments and suggestions on the previous submittal, which were received by Entergy on March 6 and August 21, 2013. This analysis updates and replaces the previous June 2013 FFA. The BART determination for each pollutant has not changed.

Entergy operates three BART-affected EGUs at White Bluff: two coal-fired primary boilers (SN-01 and SN-02) and one fuel oil-fired auxiliary boiler (SN-05). The coal-fired boilers are identical tangentially-fired boilers with a maximum net power rating of 850 MW each and a nominal heat input capacity of 8,950 million British thermal units per hour (MMBtu/hr) each. The boilers burn sub-bituminous or bituminous coal[1] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel. SN-01 and SN-02 are currently equipped with electrostatic precipitators (ESPs).

The Auxiliary Boiler, SN-05, is a 183 MMBtu/hr auxiliary boiler burning No. 2 fuel oil or biodiesel as its only fuel types. The purpose of the Auxiliary Boiler is to provide steam for the start-up of the two primary boilers, SN-01 and SN-02. There is no emissions control equipment connected to the Auxiliary Boiler. Typically, the Auxiliary Boiler is only used in the rare instance when both of the main boilers are not operating.

Based on modeling performed for this analysis, cumulative emissions of nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter with a mass mean diameter smaller than ten microns (PM_{10}) from SN-01, SN-02, and SN-05 are predicted to cause or contribute greater than 0.5 delta deciviews (Δdv) of visibility impairment in four (4) Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING)[2, 3]. A summary of the modeled visibility impairment attributable to SN-01, SN-02, and SN-05 based on default natural conditions is provided in Table 1-1. The visibility impairment summarized in Table 1-1 is based on modeling conducted by Trinity Consultants (Trinity) using emissions data based on a combination of continuous emissions monitoring system (CEMS) data as reported to EPA's Clean Air Markets Database (CAMD), stack testing, and annual emissions inventory information as further described in Section 4 of this report.

[1] SN-01 and SN-02 primarily burn sub-bituminous coal, but are permitted to burn bituminous or sub-bituminous coal. Only sub-bituminous coals were burned during the 2001-2003 and 2009-2011 baseline periods evaluated in this analysis.

[2] SN-05 does not cause visibility impairment greater than 0.5 Δdv in any Class I area but has been reviewed as part of the BART five factor analysis for the site because total impairment from the combined units is greater than 0.5 Δdv in at least one Class I area. *See* Table 4-4.

[3] Sipsey Wilderness was included in the Arkansas Department of Environmental Quality's (ADEQ's) original BART analyses, but is not included in this analysis because the EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset; *see* Section 3 and Appendix B) excludes Sipsey from the modeling domain.

TABLE 1-1. MODELED EXISTING VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01, SN-02 AND SN-05

	CACR		UPBU		HERC		MING	
Source	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**	**98th % Δdv**	**Days > 0.5 Δdv**
SN-05	0.010	0	0.005	0	0.004	0	0.008	0
SN-01	1.628	106	1.140	77	1.041	61	0.887	56
SN-02	1.695	112	1.185	80	1.060	65	0.903	57

Trinity used the EPA's BART guidelines in 40 CFR Part 51[4] and other recent EPA guidance[5] to determine BART for the boilers. Trinity conducted a five-step analysis to determine BART for SO_2 and NO_x that included the following:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

The BART analysis concluded that the installation of a semi-dry FGD system constitutes BART for SO_2 for both SN-01 and SN-02. The proposed BART emission rate for SO_2 is 0.06 lb/MMBtu on a rolling 30-day average. Since baseline visibility modeling showed that there is no opportunity for visibility improvement attributable to SN-05, because not a single day greater than 0.5 Δdv is associated with SN-05, it is not possible to install control equipment to improve visibility. Therefore, *no controls* is the SO_2 BART determination for SN-05.

The BART analysis concludes that for NO_X, the achievement of an emission rate of 0.15 lb/MMBtu through the installation and use of low NO_X burners and separated overfire air (LNB/SOFA) represents BART for SN-01 and SN-02.[6] Based on the same logic outlined above for SO_2, NO_x controls are not appropriate or required for SN-05.

[4] The BART guidelines were published as amendments to the EPA's Regional Haze Rule (RHR) in 40 CFR Part 51, Section 308 on July 6, 2005.

[5] April 26, 2012, letter from Mr. Guy Donaldson, EPA Region VI, to Mr. Anthony Davis, ADEQ.

[6] EPA recently issued a final rule allowing states that are subject to the Cross-State Air Pollution Rule (CSAPR) trading program for seasonal NO_X to rely on the reductions achieved through that trading program to satisfy the regional haze program requirements for units subject to BART. "Regional Haze: Revisions to Provisions Governing Alternatives to Source-Specific Best Available Technology (BART) Determinations, Limited SIP Disapprovals and Federal Implementation Plans," 77 Fed. Reg. 33651 (June 7, 2012). On August 21, 2012, the D.C. Circuit in a 2-1 decision vacated CSAPR (*EME Homer City Generation v. EPA*, --F. 3d --, No. 11-1302 (D.C. Cir. 2012)), and the Clean Air Interstate Rule (CAIR) remains in effect until a replacement rule, if any, is promulgated. If CSAPR ultimately is upheld and implemented in Arkansas, Entergy may rely on CSAPR to satisfy its NOx regional haze obligations at SN-01 and SN-02. Alternatively, if CSAPR is vacated and CAIR remains in place, Entergy may rely on CAIR to satisfy its NOx obligations under BART as EPA has previously determined that the CAIR season NOx trading program provides greater visibility improvement than BART.

EPA approved a BART determination for PM_{10} at SN-01 and SN-02 in its March 12, 2012, final rule based on the existing ESPs, and established a BART emission rate of 0.1 lb/MMBtu for each boiler.[7]

[7] "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 Fed. Reg. 14604 (March 12, 2012).

2. INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations.[8] The BART rule defines BART-eligible sources as sources that meet the following criteria:

1. Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant;
2. Began operation between August 7, 1962 and August 7, 1977; and
3. Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is “reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area.” EPA has determined that a source is reasonably anticipated to cause or contribute to visibility impairment if the 98th percentile visibility impacts from the source are modeled to be greater than 0.5 delta deciviews (Δdv) when compared against a natural background.[9] Air quality modeling is the tool that is used to determine a source’s visibility impacts.

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

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

[8] The BART guidelines were published as amendments to the EPA’s RHR in 40 CFR Part 51, Section 308.

[9] The original modeling for Arkansas sources relied on screening met data and, as such, reviewed the maximum impact rather than the 98th percentile impact. Use of the 98th percentile impact based on the use of refined met data (such as that used in the modeling conducted as part of this BART analysis) is consistent with both the EPA’s 2005 BART rule and the 2005 Central Regional Air Planning Association (CENRAP) BART modeling guidelines.

Specifically, the BART rule states that a BART determination should address the following five statutory factors:

1. Existing controls;
2. Cost of controls;
3. Energy and non-air quality environmental impacts;
4. Remaining useful life of the source; and
5. Degree of visibility improvement as a result of controls.

Further, the BART rule indicates that the five basic steps in a BART analysis can be summarized as follows:

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

A BART determination should be made for each visibility-affecting pollutant (VAP) by following the five steps listed above for each VAP.

SN-01 and SN-02 meet the three BART-eligibility criteria described above, and the existing visibility impairment attributable to each boiler is greater than 0.5 Δdv in at least one Class I area. Thus, SN-01 and SN-02 are subject to BART. SN-05 does not cause visibility impairment greater than 0.5 Δdv in any Class I area[10] but has been reviewed as part of the BART five factor analysis for the site because total impairment from the combined units is greater than 0.5 Δdv in at least one Class I area. Details of the existing/baseline emissions and the contribution of the emissions to visibility impairment can be found in Section 4. The VAPs emitted by the boilers include NO_X, SO_2, and PM_{10} of various forms (filterable coarse particulate matter [PM_c], filterable fine particulate matter [PM_f], elemental carbon [EC], inorganic condensable particulate matter [IOR CPM] as sulfates [SO_4], and organic condensable particulate matter [OR CPM] also referred to as secondary organic aerosols [SOA]). The BART determinations for SO_2, NO_X, and PM_{10} can be found in Sections 5, 6, and 7, respectively.

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10 *See* Table 4-4.

3. MODELING METHODOLOGIES AND PROCEDURES

This section summarizes the dispersion modeling methodologies and procedures applied in this BART analysis. All dispersion modeling has been conducted using the CALPUFF modeling system, consisting of the CALPUFF dispersion model, the CALMET meteorological data processor, and the CALPOST post-processing program. These methodologies and procedures are consistent with the ADEQ modeling protocol submitted to EPA in June 2012.

CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model, which can simulate the effects of time and space varying meteorological conditions on pollutant transport, transformation, and removal. CALPUFF uses three-dimensional meteorological fields developed by the CALMET model. In addition to meteorological data, several other input files are used by the CALPUFF model to specify source and receptor parameters. The selection and control of CALPUFF options are determined by user-specific inputs contained in the control file. This file contains all of the necessary information to define a model run (e.g., starting date, run length, grid specifications, technical options, output options). CALPOST processes concentration, deposition, and visibility impacts based on pollutant specific concentrations predicted by CALPUFF.

3.1 CALMET AND CALPUFF

The CALPUFF data and parameters are based on the 2005 BART modeling guidelines prepared for CENRAP. The CALMET data and parameters are based on the modeling protocol included in Appendix B. Note that the protocol included in Appendix B summarizes modeling methods and procedures that were followed to predict visibility impairment as part of the BART analyses for several BART-eligible sources located in Oklahoma, the first of which was Oklahoma Gas & Electric in 2007. The CALMET dataset developed per this protocol has been used – and approved by EPA – numerous times since its development.

3.2 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).[11]

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

[11] 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.

as “delta dv,” or Δdv, based on the source and background light extinction is based on the following equation:

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

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 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 Relative Humidity (RH) adjustment factors for large and small ammonium sulfates and nitrates and for sea salts
- Rayleigh scattering parameter corrected for site-specific elevation

Tables 3-1 to Table 3-4 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 3-1. 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
MING	0.23	0.1	1.83	0.02	0.51	3.05	0.04	12

TABLE 3-2. F_L(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
MING	2.73	2.52	2.34	2.28	2.53	2.6	2.64	2.67	2.71	2.56	2.56	2.73

TABLE 3-3. 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
MING	3.74	3.38	3.07	2.97	3.39	3.52	3.57	3.64	3.72	3.47	3.43	3.74

TABLE 3-4. 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
MING	3.92	3.58	3.3	3.19	3.58	3.72	3.8	3.82	3.85	3.61	3.66	3.9

This section summarizes the existing (i.e., baseline) visibility based on air quality modeling conducted by Trinity.

4.1 NO_X, SO_2, AND PM_{10} BASELINE EMISSION RATES

Table 4-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions. The SO_2 and NO_X emission rates are the highest actual 24-hour emission rates based on CAMD data from 2001-2003 for SO_2 and from 2009-2011 for NO_X[12]. The 2001-2003 period was not used for NO_X because that period no longer represents actual operation of the boilers. In 2006, Entergy completed the addition of a neural net system and also conducted extensive boiler tuning. These projects substantially reduced NO_X emissions. Accordingly, there is a real difference in operations/emissions between the original baseline period (2001-2003) and current operations such that the 2001-2003 time period is not representative of current (and thus future, post-BART) operations. The BART regulation, at 40 CFR Part 51, Appendix Y, Section IV.D.4.c, speaks to this issue:

> *The baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period. When you project that future operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) will differ from past practice, and if this projection has a deciding effect in the BART determination, then you must make these parameters or assumptions into enforceable limitations. In the absence of enforceable limitations, you calculate baseline emissions based upon continuation of past practice.*

Using the emission rates from 2001-2003 for NO_X would over-state the emissions reductions from the proposed BART control technology. Moreover, using the 2001-2003 NO_X emission rates would exaggerate the projected visibility improvement in the Class I areas. Thus, updating the NO_X emission rates to represent current, normal operation better comports with the regulations. Entergy submitted a determination request to ADEQ on August 23, 2012, to use the 2009-2011 NO_X emission rates based on CEMS data. ADEQ and EPA determined that using the 2009-2011 NO_X emission rates is consistent with the BART guidance[13].

The PM_{10} emission rates are based on emission factors from AP-42 for PM_{10} filterable and PM condensable with a 99.5% control efficiency for ESP applied to the PM_{10} filterable in conjunction with the average coal heat value and average coal % ash from 2009-2011. The emission rates for the PM_{10} species reflect the breakdown of the PM_{10} determined from the National Park Service (NPS)

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[12] *See* Appendix D.

[13] *See* Email, dated September 10, 2012, from Guy Donaldson (EPA, Region VI) to Mary Pettyjohn (ADEQ).

"speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*.[14] More specifically, the NPS workbook shows the following baseline distribution for the PM species:

- ▲ Coarse PM (PM_C) = 33.6%
- ▲ Fine soil (modeled as PM_F) = 25.9%
- ▲ Fine elemental carbon (modeled as EC) = 1.0 %
- ▲ Organic condensable PM (modeled as SOA) = 7.9%
- ▲ Inorganic condensable PM (modeled as SO_4) = 31.6%

TABLE 4-1. BASELINE MAXIMUM 24-HOUR SO_2, NO_X, AND PM_{10} EMISSION RATES (AS HOURLY EQUIVALENTS)

Source	SO_2[15] (lb/hr)	NO_X[16] (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
SN-05	5.8	31.7	2.8	0.9	0.5	1.2	0.2	0.1
SN-01	7,763.5	3,001.4	118.6	36.8	40.4	31.1	9.2	1.2
SN-02	7,825.1	3,527.4	118.6	36.8	40.4	31.1	9.2	1.2

4.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to estimate the current visibility impairment attributable to SN-01, SN-02, and SN-05 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.[17] Table 4-2, Table 4-3, and Table 4-4 provide a summary of the modeled visibility impairment attributable to SN-01, SN-02, and SN-05 respectively, based on the emission rates shown in Table 4-1. These tables show the maximum impairment in Δdv, the 98th percentile impacts in Δdv, and the number of days with impacts greater than 0.5 Δdv as well as the breakdown by pollutant species for the 98th percentile impact.

As BART is determined on a unit-by-unit basis, this baseline modeling is presented to show how the BART proposed controls will cause improvement, at least on a relative basis.

All of the CALMET, CALPUFF, and CALPOST modeling files used to generate these results are included as part of the electronic files submitted with this document.

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[14] The NPS Workbook, "PC Dry Bottom ESP Example.xls" updated 03/2006, was obtained from the NPS website: http://www.nature.nps.gov/air/Permits/ect/index.cfm. The following parameters were input into the workbook for speciation determination: total PM_{10} emission rate of 118.6 lb/hr, heat value of 8,950 Btu/lb, sulfur content of 0.27% and, ash content of 4.87%.

[15] The SO_2 hourly rates were derived from EPA's CAMD data for 2001 - 2003. The 2001-2003 max daily rates were 183,324 lb/day and 187,802 lb/day for SN-01 and SN-02, respectively. *See* Appendix D.

[16] The NO_X hourly rates were derived from EPA's CAMD data for 2009-2011. The 2001-2003 max daily rates were 72,034 lb/day and 84,658 lb/day for SN-01 and SN-02, respectively. *See* Appendix D.

[17] Due to an EPA-requested change in meteorological data which excluded Sipsey Class 1 Area from the modeling domain, Sipsey was not included in this analysis. *See* footnote 1, above.

TABLE 4-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 BY POLLUTANT

Year	Maximum (Δdv)	98^{th} Percentile (Δdv)	No. of Day with $\Delta dv \geq 0.5$	98^{th} Percentile Δdv SO_4	98^{th} Percentile Δdv NO_3	98^{th} Percentile Δdv PM_{10}	98^{th} Percentile Δdv NO_2
Caney Creek Wilderness							
2001	2.956	1.628	41	1.287	0.336	0.003	0.002
2002	2.111	1.386	30	0.662	0.659	0.011	0.054
2003	4.194	1.130	35	0.722	0.385	0.003	0.020
Upper Buffalo Wilderness							
2001	2.339	1.128	34	0.835	0.290	0.003	0.000
2002	1.544	0.818	18	0.680	0.133	0.003	0.002
2003	1.900	1.140	25	1.117	0.021	0.003	0.000
Hercules Glades Wilderness							
2001	1.737	1.041	28	0.961	0.078	0.002	0.000
2002	1.288	0.617	13	0.487	0.128	0.001	0.000
2003	2.230	0.786	20	0.699	0.085	0.002	0.000
Mingo Wilderness							
2001	1.569	0.887	18	0.828	0.053	0.003	0.002
2002	1.012	0.750	24	0.427	0.319	0.002	0.002
2003	1.114	0.702	14	0.448	0.245	0.003	0.007

Table 4-2 demonstrates that the 98^{th} percentile impacts from SO_4 are always greater than the 98^{th} percentile impacts from NO_3. Therefore, SO_4, and by default SO_2, is clearly the dominating pollutant of concern from SN-01.

TABLE 4-3. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-02 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with $\Delta dv \geq 0.5$	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek Wilderness							
2001	3.199	1.695	41	1.292	0.398	0.003	0.002
2002	2.270	1.481	33	0.964	0.465	0.011	0.041
2003	4.437	1.169	38	0.595	0.555	0.004	0.015
Upper Buffalo Wilderness							
2001	2.385	1.185	35	0.840	0.343	0.003	0.000
2002	1.618	0.846	20	0.685	0.156	0.003	0.003
2003	1.998	1.176	25	0.958	0.215	0.003	0.000
Hercules Glades Wilderness							
2001	1.838	1.060	30	0.966	0.092	0.002	0.000
2002	1.340	0.643	14	0.490	0.151	0.001	0.001
2003	2.263	0.806	21	0.703	0.101	0.002	0.000
Mingo Wilderness							
2001	1.701	0.903	18	0.834	0.063	0.003	0.003
2002	1.031	0.805	25	0.674	0.129	0.002	0.000
2003	1.150	0.750	14	0.452	0.288	0.003	0.008

Table 4-3 demonstrates that the 98^{th} percentile impacts from SO_4 are always greater than the 98^{th} percentile impacts from NO_3. Therefore, as with SN-01, SO_4, and by default SO_2, is clearly the dominating pollutant of concern from SN-02.

TABLE 4-4. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-05 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with $\Delta dv \geq 0.5$	98th Percentile Δdv SO_4	98th Percentile Δdv NO_3	98th Percentile Δdv PM_{10}	98th Percentile Δdv NO_2
Caney Creek Wilderness							
2001	0.028	0.008	0	0.001	0.007	0.000	0.000
2002	0.02	0.005	0	0.001	0.004	0.000	0.000
2003	0.036	0.01	0	0.002	0.008	0.000	0.000
Upper Buffalo Wilderness							
2001	0.014	0.004	0	0.001	0.003	0.000	0.000
2002	0.009	0.004	0	0.003	0.000	0.000	0.000
2003	0.013	0.005	0	0.001	0.004	0.000	0.000
Hercules Glades Wilderness							
2001	0.007	0.004	0	0.001	0.003	0.000	0.000
2002	0.006	0.003	0	0.001	0.002	0.000	0.000
2003	0.008	0.004	0	0.002	0.001	0.000	0.000
Mingo Wilderness							
2001	0.009	0.003	0	0.000	0.003	0.000	0.000
2002	0.019	0.008	0	0.001	0.007	0.000	0.000
2003	0.015	0.003	0	0.001	0.002	0.000	0.000

Table 4-4 demonstrates that the 98th percentile impacts from the combined pollutants are well below the 0.5 Δdv threshold to be considered a contributor to visibility impairment.

5.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from SN-01 and SN-02, the BART analysis is specific to emissions of SO_2. Reductions in emissions of SO_2 will reduce visibility impairment by reducing sulfate (SO_4) formation.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for SN-01 and SN-02 are summarized in Table 5-1. The retrofit controls examined are limited to add-on controls that eliminate SO_2 after it is formed, as SN-01 and SN-02 currently use a low sulfur fuel and thus would not achieve significant additional reductions through alternative fuel supplies comparable to the most efficient add-on controls. The available SO_2 control technologies are Dry Sorbent Injection (DSI), semi-dry scrubbing, and wet scrubbing.

TABLE 5-1. AVAILABLE SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

SO_2 Control Technologies
Dry Sorbent Injection
Semi-Dry Scrubbing
Wet Scrubbing

5.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

5.2.1 DRY SORBENT INJECTION

Dry sorbent injection involves the injection of a sorbent into the exhaust gas stream where SO_2 reacts with and becomes entrained in the sorbent. The stream is then passed through a particulate control device to remove the sorbent and entrained SO_2. The process was developed as a lower cost Flue Gas Desulfurization (FGD) option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream instead of in a separate tower. 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.[18] This control is a technically feasible option for the control of SO_2 from SN-01 and SN-02.

5.2.2 SEMI-DRY SCRUBBER

There are various designs of semi-dry scrubbing; or fuel gas desulfurization (FGD); systems, including the Spray Dryer Absorber (SDA) and Circulating Dry Scrubber (CDS) designs. In the SDA design, a fine mist of lime slurry is sprayed into an absorption tower 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 tower. This leads to the formation of a dry powder which is carried out with the gas and collected with a fabric filter.

In the 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 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.

Semi-dry scrubbing control efficiencies range from 60 to 95 percent,[19] and is a technically feasible option for the control of SO_2 from SN-01 and SN-02.

5.2.3 WET SCRUBBER

Wet scrubbing involves scrubbing the exhaust gas stream with slurry comprised of lime or limestone in suspension. The process takes place in a wet scrubbing tower located downstream of a PM control device such as a fabric filter or an electrostatic precipitator (ESP) to prevent the plugging of spray nozzles and other problems caused by the presence of particulates in the scrubber. Similar to the chemistry illustrated above for spray dryer absorption, the SO_2 in the gas stream reacts with the lime or limestone slurry to form calcium sulfite and calcium sulfate. Wet lime scrubbing is generally capable of achieving 80-95 percent control.[20] Higher control efficiencies may be achieved in certain applications. This control is a technically feasible option for the control of SO_2 from SN-01 and SN-02.

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[18] "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.

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

[20] *Id.*

EPA has recently suggested the control from wet scrubbing can achieve emissions reductions of up to 97%. Engineering evaluations conducted on Unit 1 and 2 by Sargent & Lundy (S&L) suggest that a control efficiency of up to 97% may be achievable through the application of wet scrubbing for higher-sulfur coals. However, as no vendor guarantee for greater than 95% control from wet scrubbing was available, Entergy cannot confidently rely on this level of control specific to SN-01 and SN-02. Moreover, Entergy has not received any assurances from vendors or its engineering consultant, S&L, of achieving such a level on a consistent, 30-day average basis.

5.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS FOR SN-01 AND SN-02

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing the VAP. Table 5-2 provides a ranking of the control levels for the controls listed in the previous section.

TABLE 5-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE SO_2 CONTROL TECHNOLOGIES

Control Technology	Estimated Control Efficiency
Wet Scrubber	80-95%[21]
Semi-Dry Scrubber	60-95%
Dry Sorbent Injection	40-60%

5.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS FOR SN-01 AND SN-02

The fourth step in the BART analysis is the impact analysis where the impacts for those control options deemed feasible in Step 2 are evaluated. This analysis is typically conducted to demonstrate that a control technology that is more effective than another technology does not constitute BART. The BART determination guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The remaining useful life of the source

Wet and dry scrubbing are the most effective technologies at reducing SO_2. As shown in Table 5-2, both technologies can achieve 95 percent reduction in SO_2.

[21] Estimated efficiency for wet FGD for low-sulfur coals typically combusted at White Bluff. Higher efficiencies are achievable for wet FGD when burning higher-sulfur coal, but may not be achievable for the low-sulfur coal typically combusted at SN-01 and SN-02.

Site-specific specifications from S&L indicate that semi-dry scrubbing can achieve an outlet rate of 0.06 lb/MMBtu on a 30-day rolling average basis. Entergy believes that semi-dry scrubbing represents a superior technology in comparison to wet scrubbing, thus the majority of research for this analysis has been focused on this control option. Information from S&L also indicate that wet scrubbing may be able to achieve an outlet rate of 0.04 lb/MMBtu on a 30-day rolling average basis.[22] These emission levels represent reductions of 95% for semi-dry scrubbing and 97% for wet scrubbing when applied to the facility's current maximum allowable SO_2 emission rate of 1.2 lb/MMBtu. Notwithstanding a lack of vendor assurances, for the purposes of this analysis, wet scrubbing has been evaluated at an outlet SO_2 emission rate of 0.04 lb/MMBtu.

5.4.1 COST OF COMPLIANCE

Control Costs

The capital costs were annualized over a 30-year period and then added to the annual operating costs to obtain the total annualized costs. The details of the cost effectiveness calculations are provided in Appendix A of this report.

The capital and direct operating and maintenance (O&M) costs of a semi-dry scrubber used in the cost effectiveness calculations were based on vendor estimates. The indirect operating costs such as property tax and insurance are based on calculation methods published in the sixth edition of the EPA's Air Pollution Cost Control Manual for wet acid gas absorber systems. The capital and O&M costs of a wet scrubber used in the cost effectiveness calculations are based on vendor estimates for a system estimated to achieve 97% control for an inlet SO_2 rate of 2.0 lb/MMBtu (0.06 lb/MMBtu) and calculation methods published in the sixth edition of the EPA's Air Pollution Cost Control Manual. The costs for a system capable of achieving equivalent control with an inlet SO2 rate of 1.2 lb/MMBtu or 0.04 lb/MMBtuwould be approximately 5 to 6 percent higher. The capital cost associated with a wet scrubber system is considerably higher than for a semi-dry scrubber system.

It should be noted that the capital costs presented for the SO_2 control options do not include any Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a scrubber installation, which can take several years to complete. While interest expenses will certainly be incurred on a such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of this expense. In order to facilitate timely review of this revised FFA, Entergy, without waiver, has omitted this cost from the capital costs presented within this FFA.

[22] The cost estimate from S&L for a wet FGD system represents a system estimated to achieve 97% control for an inlet SO_2 rate of 2.0 lb/MMBtu (0.06 lb/MMBtu) S&L has indicated the cost for a system capable of achieving 97% control for an inlet SO_2 rate of 1.2 lb/MMBtu (0.04 lb/MMBtu) would be 5 to 6 percent higher. Entergy has not received any guarantee that an outlet SO_2 emission rate of 0.04 lb/MMBtu is consistently achievable for SN-01 or SN-02.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate was the average rate from 2001-2003, as reported by Entergy in their air emission inventories. The controlled annual emission rates were based on the lb/MMBtu levels believed to be achievable for the control technologies multiplied by the future annual heat input. The future annual heat input is based on the average hourly heat input from CAMD for 2001 to 2003 multiplied by the average annual operating hours from 2001-2003 for each boiler.

Cost Effectiveness

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 5-3 indicates that the cost effectiveness of semi-dry scrubber at an SO_2 rate of 0.06 lb/MMBtu is approximately $2,913 per ton of SO_2 removed for SN-01 and $3,355 per ton of SO_2 removed for SN-02. The incremental costs for wet scrubbing at 0.04 lb/MMBtu over semi-dry scrubbing at 0.06 lb/MMBtu are $26,701/ton for SN-01 and $27,218/ton for SN-02. As documented in Section 5.5 below, the additional cost of wet FGD is not justified in light of the negligible improvement in visibility impacts associated with this control technology.

TABLE 5-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 AND SN-02 SO_2 CONTROLS

	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input[1]	Controlled Emission Rate	SO_2 Reduced	Capital Cost	Annual Capital Cost	Annual Direct O&M	Annual Indirect O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost Compared to Semi-Dry Scrubbing	Incremental Visibility Improvement[2]
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(tpy)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
SN-01 -Semi-Dry Scrubbing	19,550	0.06	55,269,197	1,658	17,892	335,133,908	27,007,236	8,837,861	16,282,987	52,128,084	2,913	-	0.813
SN-02 - Semi-Dry Scrubbing	17,167	0.06	54,138,841	1,624	15,543	335,133,908	27,007,236	8,859,823	16,282,987	52,150,047	3,355	-	0.767
SN-01 -Wet Scrubbing	19,550	0.04	55,269,197	1,105	18,445	389,496,052	31,388,086	15,946,729	19,550,719	66,885,535	3,626	26,701	0.021
SN-02 - Wet Scrubbing	17,167	0.04	54,138,841	1,083	16,084	389,496,052	31,388,086	15,946,729	19,550,719	66,885,535	4,158	27,218	0.021

1. The future annual heat input was estimated by multiplying the average hourly heat input from CAMD for 2009-2011 for each boiler by the average number of operating hours for each boiler from 2009-2011.

2. The incremental visibility improvement for semi-dry scrubbing is the maximum visibility improvement in the 98th percentile impact compared to baseline (See Tables 5-5 and 5-6). The incremental visibility improvement for wet scrubbing is the difference between the maximum improvement due to wet scrubbing less the maximum visibility improvement from dry scrubbing (See Tables 5-5 and 5-6).

5.4.2 ENERGY IMPACTS AND NON-AIR QUALITY IMPACTS

As illustrated in Table 5-3 and in Section 5.5 below, wet scrubbing is expected to achieve approximately the same level of visibility improvement as the proposed dry scrubbing technology. However, the negative non-air quality environmental impacts are greater with wet scrubbing systems. Such impacts include a potential increase in particulate and sulfuric acid (H_2SO_4) mist emissions. In addition, wet scrubbers require increased water use and generate large volumes of wastewater and solid waste/sludge that must be managed and/or treated. This places additional burdens on the wastewater treatment and solid waste management capabilities. Moreover, if wet scrubbing produces calcium sulfite sludge, the sludge will be water-laden, and it must be stabilized for landfilling. Wet scrubbing systems require increased power requirements and increased reagent usage over dry scrubbers. Thus, from an overall environmental perspective, dry scrubbing is superior to wet scrubbing.

5.4.3 REMAINING USEFUL LIFE

The remaining useful life of SN-01 and SN-02 does not impact the annualized capital costs for either semi-dry scrubbing or wet scrubbing because the useful life of the units is anticipated to be at least as long as the capital cost recovery period, which is 30 years based on the recovery period documented for wet scrubbers for acid gas in the EPA's Control Cost Manual.

5.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS FOR SN-01 AND SN-02

A final impact analysis was conducted to assess the visibility improvement achieved by comparing the impacts associated with the baseline emission rates to the impacts associated with the controlled emission rates. Section 4 of this report documents the existing visibility impairment attributable to SN-01 and SN-02. In order to assess the visibility improvement associated with semi-dry and wet scrubbing, the controlled emission rates associated with each control technology were modeled using CALPUFF. The SO_2 emission rates associated with wet and semi-dry scrubbers were calculated as follows:

$$P * HI = 537.00 \text{ lb/hr}$$

Where:
P for wet scrubber = 0.04 lb/MMBtu
P for semi-dry scrubber = 0.06 lb/MMBtu
HI (hourly heat input) = 8,950 MMBtu/hr

Table 5-4 summarizes the lb/hr emission rates that were modeled to reflect the addition of wet and semi-dry scrubbers on SN-01 and SN-02. One important thing to note is the ammonium sulfate emission rate indicated for wet scrubbers is higher than the ammonium sulfate emission rate indicated for semi-dry scrubbers. For all PM species other than ammonium sulfate, the NPS speciation spreadsheets were relied upon to determine emission rates for PM species. For ammonium sulfate, the approach described below was used. The NO_X emission rates were modeled at the baseline rates.

Sulfur in the fuel reacts with oxygen during the combustion process to form SO_2. Some of the SO_2 is further oxidized to SO_3, which is a precursor to sulfuric acid (H_2SO_4). Sulfuric acid can react with ammonia to cause primary emissions of ammonium sulfate. According to both FGD suppliers and the EPA, wet scrubbers have less affinity for SO_3 and typically capture between 25-50% of the SO_3.[23] Since SO_3 can lead to the formation of H_2SO_4, which leads to the formation of ammonium sulfates, the higher level of SO_3 control for semi-dry scrubbers will result in lower H_2SO_4 emissions and thus lower ammonium sulfate emissions. The ammonium sulfate emission rates for semi-dry scrubbers shown in Table 5-4 were determined assuming the reduction in ammonium sulfate (SO_4) is proportional to the reduction in SO_2 from the baseline case to the controlled case (95%). The ammonium sulfate emission rates for wet scrubbers shown in Table 5-4 were determined assuming a 50% reduction in SO_4 from the baseline case to the controlled case.

TABLE 5-4. SUMMARY OF EMISSION RATES MODELED TO REFLECT SO_2 CONTROLS

Source	SO_2 (lb/hr)	SO_4[1] (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
SN-01 – Semi-Dry Scrubbing	537.0	2.7	3,001.4	1.0	1.0	0.7	0.0	5.4
SN-02 – Semi-Dry Scrubbing	537.0	2.8	3,527.4	1.0	1.0	0.7	0.0	5.6
SN-01 – Wet Scrubbing	358.0	18.4	3,001.4	6.7	6.5	4.6	0.2	36.4
SN-02 – Wet Scrubbing	358.0	18.4	3,527.4	6.7	6.5	4.6	0.2	36.4

[1] SO_4 as it is displayed in this table represents ammonium sulfate.

Comparisons of the existing visibility impacts and the visibility impacts based on wet and semi-dry scrubbing, including the maximum modeled visibility impact, 98th percentile modeled visibility impact, and the number of days with a modeled visibility impact greater than 0.5 Δdv, for each Class I area are provided in Table 5-5 and Table 5-6.

[23] In addition, according to the EPA Technical Support Document for the Rules to Reduce Interstate Transport of Fine Particulate Matter and Ozone, "More than 90 percent of SO_3/H_2SO_4 is removed in a dry FGD, while up to about 50 percent removal occurs in a wet FGD system." http://www.epa.gov/cair/pdfs/0053-2263.pdf

TABLE 5-5 SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR SN-01 (2001-2003)

	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Existing Emission Rate	4.194	1.628	106	2.339	1.140	77	2.230	1.041	61	1.569	0.887	56
Semi-Dry Scrubber	1.961	0.815	27	0.763	0.378	6	0.698	0.358	5	0.841	0.267	2
Post Control Improvement†	*2.233*	*0.813*	*79*	*1.576*	*0.762*	*71*	*1.532*	*0.683*	*56*	*0.728*	*0.620*	*54*
Wet Scrubber	1.941	0.794	26	0.774	0.350	6	0.687	0.360	3	0.838	0.271	1
Incremental Improvement over Semi-Dry Scrubber†	*0.020*	*0.021*	*1*	*-0.011*	*0.028*	*0*	*0.011*	*-0.002*	*2*	*0.003*	*-0.004*	*1*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

TABLE 5-6. SUMMARY OF MODELED IMPACTS FROM SO_2 CONTROL VISIBILITY IMPACT ANALYSIS FOR SN-02 (2001-2003)

	Caney Creek Wilderness			**Upper Buffalo Wilderness**			**Hercules Glades Wilderness**			**Mingo NWR**		
	Maximum Impact (Δdv)	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Existing Emission Rate	4.437	1.695	112	2.385	1.185	80	2.263	1.060	65	1.701	0.903	57
Semi-Dry Scrubber	2.245	0.941	35	0.888	0.418	11	0.803	0.415	6	0.977	0.310	3
Post Control Improvement†	*2.192*	*0.754*	*77*	*1.497*	*0.767*	*69*	*1.460*	*0.645*	*59*	*0.724*	*0.593*	*54*
Wet Scrubber	2.226	0.920	35	0.899	0.405	10	0.792	0.416	6	0.974	0.315	3
Post Control Improvement over Semi-Dry Scrubber†	*0.019*	*0.021*	*0*	*-0.011*	*0.013*	*1*	*0.011*	*-0.001*	*0*	*0.003*	*-0.005*	*0*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98^{th} percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

As shown in Table 5-5 and Table 5-6, based on visibility predictions from the CALPUFF modeling system, the operation of a semi-dry scrubber achieving 0.06 lb/MMBtu will result in up to a 0.813 Δdv improvement (depending on the Class I area) to the existing 98th percentile day of visibility impairment attributable to SN-01 and up to 0.767 Δdv improvement for SN-02. By comparison, wet scrubbing achieving 0.04 lb/MMBtu only adds up to an additional 0.028 Δdv improvement for SN-01 and up to 0.021 Δdv improvement for SN-02.

For convenience, Tables 5-7 and 5-8 provide a condensed summary of the predicted improvements to visibility impairment alongside the estimated control costs. While the application of wet scrubbing may be able to achieve a nominally lower outlet SO_2 emission rate, there is essentially no incremental visibility benefit of going from semi-dry scrubbing to wet scrubbing. Further, in some cases, CALPUFF predicts worse visibility impairment for wet scrubbing as opposed to semi-dry scrubbing. This is likely due to the higher SO_4 emissions associated with wet vs dry scrubbing. Overall, the very small differences in predicted visibility impacts likely fall within the relative accuracy level of CALPUFF's modeling results. Given that wet scrubbing requires a significantly higher capital investment and is more expensive from an incremental cost effectiveness standpoint than semi-dry scrubbing, it cannot be justified as BART at SN-01 and SN-02. The adverse non-air environmental impacts from wet scrubbing also make it a less desirable control technology.

TABLE 5-7. INCREMENTAL COST EFFECTIVENESS FOR SN-01 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	SO_2 Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to Semi-dry Scrubbing ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to Semi-dry Scrubbing	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Improvement in Controlled # Days > 0.5 Δdv Compared to Semi-dry Scrubbing
SN-01	Semi-dry Scrubbing	0.06	93%	17,892.26	335,133,908	52,128,084	2,913	-	Caney Creek	1.628	0.815	0.813	-	106	27	-
									Hercules-Glades	1.041	0.358	0.683	-	61	5	-
									Mingo	0.887	0.267	0.620	-	56	2	-
									Upper Buffalo	1.140	0.378	0.762	-	77	6	-
SN-01	Wet Scrubbing	0.04	95%	18,444.95	389,496,052	66,885,535	3,626	26,701	Caney Creek	1.628	0.794	0.834	0.021	106	26	1
									Hercules-Glades	1.041	0.360	0.681	-0.002	61	3	2
									Mingo	0.887	0.271	0.616	-0.004	56	1	1
									Upper Buffalo	1.140	0.350	0.790	0.028	77	6	0

TABLE 5-8. INCREMENTAL COST EFFECTIVENESS FOR SN-02 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	SO_2 Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to Semi-dry Scrubbing ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to Semi-dry Scrubbing	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Incremental Improvement in Controlled # Days > 0.5 Δdv Compared to Semi-dry Scrubbing
SN-02	Semi-dry Scrubbing	0.06	92%	15,542.83	335,133,908	52,150,047	3,355	-	Caney Creek	1.695	0.941	0.754	-	112	35	-
									Hercules-Glades	1.060	0.415	0.645	-	65	6	-
									Mingo	0.903	0.310	0.593	-	57	3	-
									Upper Buffalo	1.185	0.418	0.767	-	80	11	-
SN-02	Wet Scrubbing	0.04	95%	16,084.22	389,496,052	66,885,535	4,158	27,218	Caney Creek	1.695	0.920	0.775	0.021	112	35	0
									Hercules-Glades	1.060	0.416	0.644	-0.001	65	6	0
									Mingo	0.903	0.315	0.588	-0.005	57	3	0
									Upper Buffalo	1.185	0.405	0.780	0.013	80	10	1

5.6 PROPOSED BART FOR SO_2 FOR SN-01 AND SN-02

Entergy is proposing that the SO_2 BART emission level for SN-01 and SN-02 be 0.06 lb/MMBtu based on the installation and operation of a semi-dry scrubber or whatever technology may become available to achieve that level of control. EPA has previously agreed that "this [SDA] technology is BART for these two units."[24] Entergy is proposing to meet this limit on a 30-day rolling average basis. This emission level provides for a very small compliance margin considering the variability of the coal content for the White Bluff units; therefore, the proposed 30-day averaging period and compliance demonstration method is critical. Compliance will be demonstrated using data from the existing CEMS.

5.6.1 COMPARATIVE SO_2 BART DETERMINATIONS

EPA has agreed with similar and even less stringent SO_2 BART determinations in other states. For example, in Oklahoma,[25] EPA agreed with the BART determination of 0.06 lb/MMBtu achieved through use of dry scrubbers for similar boilers, based on the minimal visibility improvement associated with wet vs dry scrubbing.. In Nebraska[26] at GGS, BART for SO_2 was also determined to be 0.06 lb/MMBtu achieved through the use of dry scrubbers. These similar units provide a good comparison of emission levels achievable through similar control technology.

Other BART determinations have resulted in higher emission limitations. For example, in Alabama,[27] a smaller EGU was allowed an emission limitation of 0.47 lb/MMBtu through use of flue solvent injection or comparable technologies. In Arizona,[28] SO_2 BART was determined to be in the range of 0.08 – 0.15 lb/MMBtu from existing wet scrubbers. An EGU in Colorado[29] has a proposed BART emission rate of 0.13 lb/MMBtu through use of dry scrubbing. A lower emission rate of 0.09 lb/MMBtu was evaluated and determined not reasonable due to the minimal visibility improvement projected as compared to the higher costs of scrubbing to meet the lower rate.

In other determinations, such as Illinois,[30] the control technology was not stated in the BART determination but the SO_2 rate determined to be BART was in the range of 0.11 – 0.23 lb/MMBtu, dependent upon boiler type and averaging considerations. SO_2 BART in Kansas[31] was achieved through "scrubbing" with an emission limitation of 0.10 lb/MMBtu for one boiler and through wet scrubbing with an emission limitation of 0.15 lb/MMBtu for another. An EGU in Montana[32] similar to Entergy's SN-01 and SN-02 has a BART emission rate of 0.08 lb/MMBtu.

[24] November 25, 2009, letter from Mr. Jeff Robinson, EPA, to Mr. Tom Rheaume, ADEQ.
[25] 77 Fed. Reg. 16168 (March 22, 2011).
[26] 77 Fed. Reg. 40150 (July 6, 2012).
[27] 77 Fed. Reg. 11937 (February 28, 2012).
[28] 77 Fed. Reg. 42834 (July 20, 2012).
[29] 77 Fed. Reg. 18052 (March 26, 2012).
[30] 77 Fed. Reg. 3966 (January 26, 2012).
[31] 77 Fed. Reg. 52604 (August 23, 2011).
[32] 77 Fed. Reg. 23988 (April 20, 2012).

5.7 SO_2 BART FOR SN-05

The maximum visibility impairment predicted by the CALPUFF modeling system for SN-05 is only 0.036 Δdv[33]. This is an extremely low level of impairment, so low that it is likely falls within the level of accuracy that can be attributed to CALPUFF. In addition, this modeling assumes that the auxiliary boiler operates at the maximum daily emission rate 365 days per year. Since the existing visibility impairment predicted by CALPUFF is extremely low, to the point of practically being nonexistent, the impairment cannot be considered significant such as to require controls. Said another way, the impairment is so low that any improvement from reductions would be less than negligible. Therefore, no controls will be considered BART for SN-05. This conclusion is consistent with EPA's determinations for similar boilers in other states, such as the auxiliary boiler at the Basin Electric Power Cooperative's Leland Olds Station located in North Dakota or the auxiliary boiler at the Golden Valley Electric Association's Healy Power plant in Fairbanks, Alaska.

[33] *See* Table 4-4

6.1 IDENTIFICATION OF AVAILABLE RETROFIT NO_X CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

Nitrogen oxides, NO_X, are produced during fuel combustion when nitrogen contained in both the fuel and the combustion air is exposed to high temperatures. The origin of the nitrogen (i.e. fuel vs. combustion air) has led to the use of the terms "thermal" NO_X and "fuel" NO_X when describing NO_X emissions. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is exposed to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of nitrogen compounds contained in the fuel.

Nitrogen oxide (NO) is typically the predominant form of NO_X from fossil fuel combustion. Nitrogen dioxide (NO_2) makes up the remainder of the NO_X. The formation of NO_X compounds in utility boilers is sensitive to the method of firing. In tangentially-fired boilers, such as SN-01 and SN-02, a single rotating flame is created in the center of the furnace, rather than the discrete flames produced by burners in the wall-fired boilers. Tangentially fired boilers typically have lower uncontrolled NO_X emissions than wall-fired boilers. Therefore, baseline NO_X emission rates can vary significantly from plant to plant due to method of firing as well as several other factors.

Step 1 of the BART determination is the identification of all available retrofit NO_X control technologies. The available retrofit NO_X control technologies are summarized in Table 6-1 for SN-01 and SN-02.

NO_X emissions controls, as listed in Table 6-1, can be categorized as combustion or post-combustion controls. Combustion controls, including flue gas recirculation (FGR), overfire air (OFA) or separated OFA (SOFA), and Low NO_X Burners (LNB), reduce the peak flame temperature and excess air in the furnace which minimizes NO_X formation. Post-combustion controls, such as selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR), convert NO_X in the flue gas to molecular nitrogen and water.

TABLE 6-1. AVAILABLE NO_X CONTROL TECHNOLOGIES FOR SN-01 AND SN-02

NO_X Control Technologies	
Combustion Controls	Flue Gas Recirculation (FGR) Separated Overfire Air (SOFA) Low NO_X Burners (LNB)
Post-Combustion Controls	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR)

6.2 ELIMINATE TECHNICALLY INFEASIBLE NO_X CONTROL TECHNOLOGIES

Step 2 of the BART determination is to eliminate technically infeasible NO_X control technologies that were identified in Step 1. Control ranges were developed using a combination of literature control ranges and efficiencies. Because many controlled emissions rates from literature values were higher than the baseline NO_X rate at SN-01 and SN-02, vendor estimates were also used to assist in developing the expected emission rates from the known relationships between the control options.

6.2.1 Combustion Controls

6.2.1.1 Flue Gas Recirculation (FGR)

FGR uses flue gas as an inert material to reduce flame temperatures. In a typical flue gas recirculation system, flue gas is collected from the combustion chamber or stack and returned to the burner via a duct and blower. The addition of flue gas reduces the oxygen content of the "combustion air" (air + flue gas) in the burner. The lower oxygen level in the combustion zone reduces flame temperatures, which in turn reduces thermal NO_X formation. However, vendor-specific review of the White Bluff boilers has concluded that NO_X reduction efficiency data for coal-fired units with FGR are limited. The amount of NO_X reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NO_X rather than fuel NO_X. Industry experience with FGR on coal-fired units for steam temperature control has shown very high maintenance on the gas recirculation fans due to erosion and corrosion. Many of the units with FGR for steam temperature control have removed the recirculation fans from service. The NO_X control achievable on tangentially fired units like White Bluff – Units 1&2 with LNB+OFA has been comparable to that of FGR at lower capital and O&M cost. Currently, FGR technology is not offered by OEMs for coal-fired units. For these reasons, FGR is not a feasible technology for the White Bluff coal-fired units.

6.2.1.2 Overfire Air (OFA) / Separated Overfire Air (SOFA)

OFA diverts a portion of the total combustion air from the burners and injects it through separate air ports above the top level of burners. Staging of the combustion air creates an initial fuel-rich combustion zone with a lower peak flame temperature. This reduces the formation of thermal NO_X by lowering combustion temperature and limiting the availability of oxygen in the combustion zone where NO_X is most likely to be formed.

SOFA refers to a system wherein the OFA is injected in a separate wind box mounted above the main wind box in order to achieve greater separation from the combustion zone resulting in more effective NO_X suppression. SOFA as a single NO_X control technique results in estimated NO_X emissions for coal fired boilers of approximately 10%,[34] or 0.28-0.32 lb/MMBtu from SN-01 and SN-02. This control is a technically feasible option for the control of NO_X from SN-01 and SN-02.

[34] *Id.*

6.2.1.3 LOW NO_X BURNERS (LNB)

LNB technology utilizes advanced burner design to reduce NO_X formation through the restriction of oxygen, lowering of flame temperature, and/or reduced residence time. NO_X creation rates typically peak at oxygen levels of five to seven percent.[35] LNB is a staged combustion process that is designed to split fuel combustion into two zones. In the primary zone, NO_X formation is limited by one of two methods. Under staged fuel-rich conditions, low oxygen levels limit flame temperatures resulting in less NO_X formation. The primary zone is then followed by a secondary zone in which the incomplete combustion products formed in the primary zone act as reducing agents. Alternatively, under staged fuel-lean conditions, excess air will reduce flame temperature to reduce NO_X formation. In the secondary zone, combustion products formed in the primary zone act to lower the local oxygen concentration, resulting in a decrease in NO_X formation.

When combined with SOFA, the estimated NO_X emission rate is 0.15 lb/MMBtu.[36] LNB systems with SOFA are technically feasible for the control of NO_X from SN-01 and SN-02.

6.2.2 POST COMBUSTION CONTROLS

6.2.2.1 SELECTIVE CATALYTIC REDUCTION (SCR)

SCR refers to the process in which NO_X is reduced by ammonia over a heterogeneous catalyst in the presence of oxygen. The process is termed selective because the ammonia preferentially reacts with NO_X rather than oxygen, although the oxygen enhances the reaction and is a necessary component of the process. The overall reactions are:

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O$$
$$2NO_2 + 4NH_3 + O_2 \rightarrow 3N_2 + 6H_2O$$

The SCR process requires a reactor, a catalyst, and an ammonia storage and injection system. The effectiveness of an SCR system is dependent on a variety of factors, including the inlet NO_X concentration, the exhaust temperature, the ammonia injection rate, and the type of catalyst. When combined with LNB and OFA, the estimated NO_X emission rate is 0.055 lb/MMBtu.[37] This control is a technically feasible option for the control of NO_X from SN-01 and SN-02.

6.2.2.2 SELECTIVE NON-CATALYTIC REDUCTION (SNCR)

In SNCR systems, a reagent is injected into the flue gas in the furnace within an appropriate temperature window. The NO_X and reagent (ammonia or urea)

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[35] http://www.energysolutionscenter.org/boilerburner/Workshop/RCTCombustion.htm.

[36] 2012 S&L NOx Study.

[37] *Id.*, this rate includes consideration of normal fluctuations which may occur over a 30-day compliance period.

react to form nitrogen and water. A typical SNCR system consists of reagent storage, multi-level reagent-injection equipment, and associated control instrumentation. The SNCR reagent storage and handling systems are similar to those for SCR systems. However, both ammonia and urea SNCR processes require three to four times as much reagent as SCR systems to achieve similar NO_X reductions. When combined with LNB/OFA, the estimated NO_X emission rate is 0.13 lb/MMBtu.[38] This control is a technically feasible option for the control of NO_X from SN-01 and SN-02.

[38] *Id.*

6.3 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to rank the technically feasible options according to effectiveness. Table 6-2 provides a ranking of the control levels for the controls listed in the previous section.

TABLE 6-2. CONTROL EFFECTIVENESS OF TECHNICALLY FEASIBLE NO_X CONTROL TECHNOLOGIES

Control Technology	Estimated Controlled Level for SN-01 and SN-02 (lb/MMBtu)
SOFA	0.28-0.32
LNB/SOFA	0.15
LNB/SOFA + SNCR	0.13
LNB/SOFA + SCR	0.055

Current NO_X emissions are approximately 0.31 lb/MMBtu from SN-01 and approximately 0.36 lb/MMBtu from SN-02. Based on evaluations by S&L, it is believed that combustion controls such as LNB in combination with SOFA will achieve a NO_X level of 0.15 lb/MMBtu for SN-01 and SN-02.[39] Further, it is believed that the addition of SCR to LNB/SOFA will achieve a NO_X level of approximately 0.055 lb/MMBtu at each unit and LNB/SOFA + SNCR will achieve a level of 0.13 lb/MMBtu at each unit.

6.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS

Step four for the BART analysis is the impact analysis. The BART determination guidelines list four factors to be considered in the impact analysis:

- ▲ Cost of compliance;
- ▲ Energy impacts;
- ▲ Non-air quality impacts; and
- ▲ The remaining useful life of the source.

6.4.1 COST OF COMPLIANCE

The capital costs, operating costs, and cost effectiveness of LNB/SOFA, LNB/SOFA + SNCR and LNB/SOFA + SCR were estimated for the cost analysis.

[39] EPA established presumptive SO_2 and NO_X controls for coal-fired EGUs in the BART rule. For dry bottom tangentially-fired EGUs, the presumptive NO_X limit is 0.15 lb/MMBtu. (Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART Determinations; Final Rule.") 77 FR 39134 (July 6, 2005).

Control Costs

Control costs were calculated using vendor capital and operating cost estimates specific to the units. The capital costs were annualized over a 30-year period and then added to the annual operating costs to obtain the total annualized costs.

The details of the capital and operating cost estimates are provided in Appendix A of this report.

It should be noted that the capital costs presented for the various NO_x control options do not include any Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a NOx controls installation, during the construction phase, which can take many months to several years to complete. While interest expenses will certainly be incurred on a such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of this expense. In order to facilitate review of this revised FFA, Entergy, without waiver, has omitted this cost from the capital costs presented within this FFA.

Annual Tons Reduced

The annual tons reduced that were used in the cost effectiveness calculations were determined by subtracting the estimated controlled annual emission rate from the baseline annual emission rate.

The baseline annual emission rates were the average rates from 2009-2011, as reported by Entergy in their air emission inventories. The controlled annual emission rate is based on the lb/MMBtu level believed to be achievable from the control technology multiplied by the future annual input to the boiler in MMBtu/yr. The future annual heat input is based on the average hourly heat input from CAMD for 2001 to 2003 multiplied by the average annual operating hours from 2001to 2003 for each boiler. This was the same approach that was used to estimate future annual heat input in the review of SO_2 controls

Cost Effectiveness

The cost effectiveness in dollars per ton of NO_X reduced was determined by dividing the annualized cost of control by the annual tons reduced. An incremental cost analysis was also performed to show the incremental increase in costs between LNB/SOFA + SCR and an LNB/SOFA system, as well as between LNB/SOFA + SNCR and LNB/SOFA. The costs effectiveness analysis is summarized in Table 6-3.

In the BART guidelines, EPA calculated that for all types of boilers other than cyclone boilers, combustion control technology is generally more cost-effective than post-combustion controls. EPA estimates that approximately 75 percent of the BART units (non-cyclone) could meet the presumptive NO_X limits at a cost of $100 to $1,000 per ton of

NO_X removed based on the use of combustion control technology.[40] For the units that could not meet the presumptive limits using combustion control technology, EPA estimates that almost all of these sources could meet the presumptive limits using advanced combustion controls. The EPA estimates that the costs of such controls are usually less than $1,500 per ton of NO_X removed.[41]

Table 6-3 indicates that the cost effectiveness of LNB/SOFA is approximately $375 per ton of NO_X removed. Installing LNB/SOFA would reduce NO_X emissions by more than 50%. By contrast, the incremental cost effectiveness of adding SNCR to LNB/SOFA is approximately $10,000/ton per unit. Similarly, the incremental cost of adding SCR to LNB/SOFA is approximately $7,250-$8,000/ton per unit.

Table 6-3 also demonstrates the improvement in the maximum of the 98th percentile visibility impairment results due to each control technology. As Table 6-3 clearly shows, LNB/SOFA + SNCR offers very little visibility improvement over LNB/SOFA alone (~0.03 dv). The addition of SCR incrementally improves visibility over LNB/SOFA by only approximately 0.1 dv at an annual cost of well over $20,000,000 per unit. Such a large cost cannot be justified by the negligible visibility improvement provided by SCR.

40 *Id.* at 39134-39135.

41 *Id.*

TABLE 6-3. SUMMARY OF COST EFFECTIVENESS FOR SN-01 AND SN-02 NO_X CONTROLS

	Baseline Emission Rate	Controlled Emission Level	Annual Heat Input[1]	Controlled Emission Rate	NOx Reduced	Capital Cost	Annual Capital Cost	Annual Fixed O&M	Annualized Variable O&M	Total Annual Cost	Cost Effectiveness	Incremental Cost Compared to LNB/SOFA	Incremental Visbility Improvement[2]
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
SN-01 LNB/SOFA	7,249.23	0.15	55,269,197	4145.19	3104.04	10,461,206	843,031	142,000	177,887	1,162,918	375	-	0.176
SN-01 LNB/SOFA/SNCR	7,249.23	0.13	55,269,197	3592.50	3656.73	21,371,325	1,722,238	311,000	4,538,000	6,571,238	1,797	9,785	0.024
SN-01 LNB/SOFA/SCR	7,249.23	0.055	55,269,197	1519.90	5729.33	230,329,138	18,561,397	608,000	2,836,000	22,005,397	3,841	7,939	0.093
	(tpy)	(lb/MMBtu)	(MMBtu/yr)	(tpy)	(ton/yr)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)	(dv)
SN-02 LNB/SOFA	8,185.33	0.15	54,138,841	4060.41	4124.91	14,488,206	1,167,552	142,000	170,838	1,480,391	359	-	0.225
SN-02 LNB/SOFA/SNCR	8,185.33	0.13	54,138,841	3519.02	4666.30	25,398,325	2,046,760	311,000	4,542,000	6,899,760	1,479	10,010	0.033
SN-02 LNB/SOFA/SCR	8,185.33	0.055	54,138,841	1488.82	6696.51	206,747,898	16,661,070	608,000	2,858,000	20,127,070	3,006	7,251	0.102

1. The future annual heat input was estimated by multiplying the average hourly heat input from CAMD for 2009-2011 for each boiler by the average number of operating hours for each boiler from 2009-2011.

2. The incremental visibility improvement for LNB/SOFA is the maximum visibility improvement in the 98th percentile impact compared to baseline (See Tables 6-5 and 6-6). The incremental visibility improvement for LNB/SOFA/SNCR and LNB/SOFA/SCR is the difference between the maximum improvement due to LNB/SOFA/SNCR or LNB/SOFA/SCR in the four Class I areas considered in the analysis less the maximum visibility improvement in the four Class I areas from LNB/SOFA (See Tables 6-5 and 6-6).

6.4.2 ENERGY IMPACTS & NON-AIR IMPACTS

As noted in Table 6-3 and in Section 6.5 below, SCR and SNCR systems are capable of achieving additional NO_X mass emission reductions in comparison to combustion controls such as LNB/SOFA. However, both SCR and SNCR systems create additional energy and/or non-air environmental impacts. SCR and SNCR systems require electricity to operate the ancillary equipment. The need for electricity to help power some of the ancillary equipment creates a demand for energy that currently does not exist.

SCR and SNCR can potentially cause significant environmental impacts. The primary avenue is related to the storage of ammonia. The storage of aqueous ammonia above 10,000 lbs is regulated by a risk management program (RMP), since the accidental release of ammonia has the potential to cause serious injury and death to persons in the vicinity of the release. Additionally, SCR and SNCR will likely also cause the release of unreacted ammonia to the atmosphere. This is referred to as ammonia slip. Ammonia slip from SCR and SNCR systems occurs either from ammonia injection at temperatures too low for effective reaction with NO_X, leading to an excess of unreacted ammonia, or from over-injection of reagent leading to uneven distribution; which also leads to an excess of unreacted ammonia. Ammonia released from SCR and SNCR systems will react with sulfates and nitrates in the atmosphere to form ammonium sulfate and ammonium nitrate. Together, ammonium sulfate and ammonium nitrate are the predominant sources of regional haze.

Another environmental impact associated with SCR is the disposal of catalyst waste. To maintain NO_X-removal effectiveness, the catalyst in an SCR system must periodically be cleaned, regenerated, or replaced. Cleaning and regeneration are preferred, but eventually the catalyst reaches the end of its useful life and must be replaced. Ideally the exhausted catalyst can be recycled for reuse, however, if the condition of the spent catalyst does not warrant recycling or a market is unavailable, the old catalyst must be disposed of. Current regulatory interpretations indicate spent SCR catalysts are exempted from hazardous waste regulation via 40 CFR § 261.4(b)(4) (Bevill Exemption) as flue gas emission control wastes. However, ongoing efforts by EPA to increase regulatory oversight of coal combustion residuals could alter that exemption, and create the potential that spent SCR catalysts would be characterized as hazardous wastes, hence increasing the cost of disposal. Regardless of the regulatory treatment of the waste, the disposal creates additional potential financial and environmental impacts associated with an SCR system.

6.4.3 REMAINING USEFUL LIFE

The remaining useful life of SN-01 and SN-02 are sufficiently long such that it does not affect the BART analysis.

6.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE NO_X CONTROLS

A final impact analysis was conducted to assess the visibility improvement for existing emission rates when compared to the emission rates associated with LNB/SOFA, LNB/SOFA + SNCR and LNB/SOFA + SCR. Section 4 of this report documented the existing visibility impairment attributable to SN-01 and SN-02. In order to assess the visibility improvement associated with LNB/SOFA, SCR and SNCR systems, the NO_X emission rates associated with the control systems were modeled using CALPUFF. The controlled emission level associated with LNB/SOFA system is 0.15 lb/MMBtu; the controlled emission level associated with SOFA + SNCR is 0.13 lb/MMBtu; and the controlled emission level associated with LNB/SOFA + SCR systems is 0.055 lb/MMBtu for each unit. These levels were multiplied by the maximum heat input to derive the hourly emission rates used in the modeling.

Table 6-4 summarizes the NO_X emission rates that were modeled to reflect the LNB/SOFA, LNB/SOFA + SNCR, and LNB/SOFA + SCR. The emission rates for the other pollutants shown in Tables 6-4 are the same as in the baseline modeling.

TABLE 6-4. SUMMARY OF EMISSION RATES MODELED TO REFLECT NO_X CONTROLS

	SO_2 (lb/hr)	SO_4 (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	SOA (lb/hr)	EC (lb/hr)	$PM_{10, total}$ (lb/hr)
SN-01 – LNB/SOFA	7,763.5	36.8	1342.5	40.4	31.1	9.2	1.2	118.6
SN-02 – LNB/SOFA	7,825.1	36.8	1342.5	40.4	31.1	9.2	1.2	118.6
SN-01 - LNB/SOFA + SNCR	7,763.5	36.8	1163.5	40.4	31.1	9.2	1.2	118.6
SN-02 - LNB/SOFA + SNCR	7,825.1	36.8	1163.5	40.4	31.1	9.2	1.2	118.6
SN-01 – LNB/SOFA + SCR	7,763.5	36.8	492.3	40.4	31.1	9.2	1.2	118.6
SN-02 - LNB/SOFA + SCR	7,825.1	36.8	492.3	40.4	31.1	9.2	1.2	118.6

Tables 6-5 and 6-6 provide a comparison of the existing visibility impairment and the visibility impairment associated with the addition of NO_X controls on SN-01 and SN-02, respectively, in all affected Class I areas, including 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.

TABLE 6-5. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEMS ON SN-01 (2001-2003)

	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Existing Emission Rate	4.194	1.628	106	2.339	1.140	77	2.230	1.041	61	1.569	0.887	56
LNB/OFA	3.465	1.462	89	2.243	1.039	62	2.175	0.865	48	1.168	0.849	45
Post Control Improvement	*0.729*	*0.166*	*17*	*0.096*	*0.101*	*15*	*0.055*	*0.176*	*13*	*0.401*	*0.038*	*11*
LNB/OFA + SNCR	3.386	1.428	86	2.233	1.029	62	2.170	0.844	47	1.146	0.842	44
Incremental Improvement Over LNB/SOFA	*0.079*	*0.034*	*3*	*0.010*	*0.01*	*0*	*0.005*	*0.021*	*1*	*0.022*	*0.007*	*1*
LNB/OFA + SCR	3.089	1.359	73	2.196	0.991	59	2.148	0.832	45	1.132	0.817	38
Incremental Improvement Over LNB/OFA	*0.376*	*0.103*	*16*	*0.047*	*0.048*	*3*	*0.027*	*0.033*	*3*	*0.036*	*0.032*	*7*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

TABLE 6-6. SUMMARY OF VISIBILITY IMPROVEMENT ASSOCIATED WITH NO_X CONTROL SYSTEMS ON SN-02 (2001-2003)

\	Caney Creek Wilderness			Upper Buffalo Wilderness			Hercules Glades Wilderness			Mingo NWR		
	Maximum Impact (Δdv)	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**Maximum Impact (Δdv)**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Existing Emission Rate	4.437	1.695	112	2.385	1.185	80	2.263	1.060	65	1.701	0.903	57
LNB/SOFA	3.483	1.47	91	2.258	1.046	62	2.191	0.870	48	1.174	0.856	45
Post Control Improvement	*0.954*	*0.225*	*21*	*0.127*	*0.139*	*18*	*0.072*	*0.190*	*17*	*0.527*	*0.047*	*12*
LNB/SOFA + SNCR	3.404	1.437	87	2.248	1.035	62	2.185	0.849	47	1.152	0.849	45
Incremental Improvement Over LNB/SOFA	*0.079*	*0.033*	*4*	*0.010*	*0.011*	*0*	*0.006*	*0.021*	*1*	*0.022*	*0.007*	*0*
LNB/SOFA + SCR	3.107	1.368	75	2.211	0.997	59	2.164	0.838	45	1.138	0.823	39
Incremental Improvement Over LNB/SOFA	*0.376*	*0.102*	*16*	*0.047*	*0.049*	*3*	*0.027*	*0.032*	*3*	*0.036*	*0.033*	*6*

†The visibility improvement shown in the table has been calculated from values that include more decimal places than what is shown in the table. Due to rounding, the visibility improvement calculated from the baseline and controlled 98th percentile impacts shown in the table may be slightly different than the visibility improvement reflected in the table.

In light of the very small incremental visibility benefit and the high marginal cost, SNCR cannot be considered BART for either SN-01 or SN-02. As shown in Table 6-5 and Table 6-6, based on visibility predictions from the CALPUFF modeling system, the operation of a LNB/SOFA will result in up to a 0.176 Δdv improvement (depending on the Class I area) to the existing visibility impairment attributable to SN-01 and up to 0.225 Δdv improvement for SN-02. There is essentially zero visibility improvement due to including SNCR, with a modeled change of approximately 0.03 Δdv for both units. The addition of SCR would produce a modeled improvement of only 0.103 Δdv for Unit 1 and 0.102 Δdv for Unit 2 over LNB/SOFA alone.

Tables 6-7 and 6-8 provide a condensed summary of these predicted improvements alongside the estimated control costs. The incremental benefit of going from LNB/SOFA to either LNB/SOFA + SCNR or LNB/SOFA + SCR is clearly not justified. The control technologies are very expensive in terms of initial capital investment and are prohibitively more expensive from an incremental cost effectiveness standpoint than LNB/SOFA alone.

TABLE 6-7. INCREMENTAL COST EFFECTIVENESS FOR SN-01 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to LNB/SOFA ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to LNB/SOFA	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Incremental Improvement in Controlled # Days > 0.5 Δdv Compared to LNB/SOFA
SN-01	LNB/SOFA	0.15	51%	3,104.04	10,461,206	1,162,918	375	-	Caney Creek	1.628	1.462	0.166	-	106	89	-
									Hercules-Glades	1.041	0.865	0.176	-	61	48	-
									Mingo	0.887	0.849	0.038	-	56	45	-
									Upper Buffalo	1.140	1.039	0.101	-	77	62	-
SN-01	LNB/SOFA + SNCR	0.13	58%	3,656.73	21,371,325	6,571,238	1,797	9,785	Caney Creek	1.628	1.428	0.200	0.034	106	86	3
									Hercules-Glades	1.041	0.844	0.197	0.021	61	47	1
									Mingo	0.887	0.842	0.045	0.007	56	44	1
									Upper Buffalo	1.140	1.029	0.111	0.010	77	62	0
SN-01	LNB/SOFA + SCR	0.055	82%	5,729.33	230,329,138	22,005,397	3,841	7,939	Caney Creek	1.628	1.359	0.269	0.103	106	73	16
									Hercules-Glades	1.041	0.832	0.209	0.033	61	45	3
									Mingo	0.887	0.817	0.070	0.032	56	38	7
									Upper Buffalo	1.140	0.991	0.149	0.048	77	59	3

TABLE 6-8. INCREMENTAL COST EFFECTIVENESS FOR SN-02 WITH CLASS I AREA IMPROVEMENT

Unit ID	Control Description	NOx Emissions (lb/MMBtu)	Control Eff. From Baseline (%)	Emission Reduction from Baseline (tons/yr)	Installed Cost ($)	Total Annual Control Cost ($)	Pollution Control Cost ($/ton)	Incremental Cost Compared to LNB/SOFA ($/ton)	Class I Area	Baseline 98th Percentile Δdv	Controlled 98th Percentile Δdv	Improvement in 98th Percentile Δdv	Incremental Improvement in 98th Percentile Δdv Compared to LNB/SOFA	Baseline # Days > 0.5 Δdv	Controlled # Days > 0.5 Δdv	Incremental Improvement in Controlled # Days > 0.5 Δdv Compared to LNB/SOFA
SN-02	LNB/SOFA	0.15	58%	4,124.91	14,488,206	1,480,391	359	-	Caney Creek	1.695	1.470	0.225	-	112	91	-
									Hercules-Glades	1.060	0.870	0.190	-	65	48	-
									Mingo	0.903	0.856	0.047	-	57	45	-
									Upper Buffalo	1.185	1.046	0.139	-	80	62	-
SN-02	LNB/SOFA + SNCR	0.13	63%	4,666.30	206,747,898	6,899,760	1,479	10,010	Caney Creek	1.695	1.437	0.258	0.033	112	87	4
									Hercules-Glades	1.060	0.849	0.211	0.021	65	47	1
									Mingo	0.903	0.849	0.054	0.007	57	45	0
									Upper Buffalo	1.185	1.035	0.150	0.011	80	62	0
SN-02	LNB/SOFA + SCR	0.055	85%	6,696.51	206,747,898	20,127,070	3,006	7,251	Caney Creek	1.695	1.368	0.327	0.102	112	75	16
									Hercules-Glades	1.060	0.838	0.222	0.032	65	45	3
									Mingo	0.903	0.823	0.080	0.033	57	39	6
									Upper Buffalo	1.185	0.997	0.188	0.049	80	59	3

6.6 PROPOSED BART FOR NO_X FOR SN-01 AND SN-02

If CSAPR ultimately is upheld and implemented in Arkansas, Entergy may rely on CSAPR to satisfy its NO_X regional haze obligations at SN-01 and SN-02. Alternatively, if CSAPR is vacated and CAIR remains in place, Entergy may rely on CAIR to satisfy its NO_X obligations under BART as EPA has previously determined that the CAIR season NO_X trading program provides greater visibility improvement than BART.

With full consideration of all five factors outlined by EPA for BART determinations, Entergy proposes a BART emission level of 0.15 lb/MMBtu on a 30-day rolling average basis, achievable through use of LNB/SOFA at SN-01 and SN-02. Compliance will be demonstrated using data from the existing CEMS. This determination is consistent with the BART determinations approved by EPA in Oklahoma, including the determinations for OG&E Seminole Units 1, 2, and 3 that combustion controls achieving 30-day rolling average NO_X levels of 0.203 lb/MMBtu, 0.212 lb/MMBtu, and 0.164 lb/MMBtu, respectively, constitute BART and the determination for OG&E Sooner Units 1 and 2, OG&E Muskogee Unit 4, and AEP/PSO Northeastern Units 3 and 4 that combustion controls achieving a 30-day rolling average NO_X level of 0.15 lb/MMBtu constitute BART.[42]

6.7 PROPOSED BART FOR NO_X FOR SN-05

The maximum visibility impairment predicted by the CALPUFF modeling system for SN-05 is only 0.036 Δdv[43]. This is an extremely low level of impairment, so low that it is likely falls within the level of accuracy that can be attributed to CALPUFF. In addition, this modeling assumes that the auxiliary boiler operates at the maximum daily emission rate 365 days per year. Since the existing visibility impairment predicted by CALPUFF is extremely low, to the point of practically being nonexistent, the impairment cannot be considered significant such as to require controls. Said another way, the impairment is so low that any improvement from reductions would be less than negligible. Therefore, *no controls* is the NO_X BART determination for SN-05. This conclusion is consistent with EPA's determinations in other states with similar auxiliary boilers.

[42] 77 Fed. Reg. 16168 (March 22, 2011).

[43] *See* Table 4-4

EPA's Approval and Promulgation of Implementation Plans, published March 12, 2012, determined that the currently installed ESP is BART for PM_{10} for SN-01 and SN-02.

> The federally enforceable operating air permit states the PM emissions from the two units are controlled with ESPs and requires that the two units comply with a PM emission standard of 0.10 lb/MMBtu. Since we have found that the visibility impact of the source due to PM emissions alone is so minimal such that the installation of any additional PM controls on the units would likely achieve very low emissions reductions, have minimal visibility benefits, and not be cost-effective, we are proposing to approve ADEQ's determination that PM BART for both the bituminous and subbituminous coal firing scenarios is the existing PM emission limit for Units 1 and 2.[44]

As such, no further PM_{10} analysis has been conducted.

Section 4 of this report summarized the baseline visibility impairment attributable to SN-01, SN-02 and SN-05. Table 4-4 demonstrates that SN-05 does not contribute to a single day of visibility impairment greater than 0.5 Δdv. Therefore, no controls will be considered BART for SN-05. This conclusion is consistent with EPA's determinations in other states with similar auxiliary boilers.

44 "Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Final Rule," 77 FR 14658 (March 12, 2012).

APPENDIX A

SO_2 AND NO_X CONTROL COST CALCULATIONS

Semi-Dry Scrubber Capital and O&M Cost Estimate			
Operational Data		**Unit 1**	**Unit 2**
Maximum HI (MMBtu/hr)		8950	8950
Annual Operating Hours, 2009-2011		7361	7401
Capital Costs[1]		**Unit 1**	**Unit 2**
Total Contractor Costs (2012 Dollars)		$174,854,437	$174,854,437
Total Contractor Costs (2010 Dollars):		$156,974,274	$156,974,274
FGD Equipment (2010 Dollars)		$57,649,982	$57,649,982
FGD Materials (2010 Dollars)		$14,840,928	$14,840,928
FGD Contractor Labor (2010 Dollars)		$63,607,654	$63,607,654
FGD Contractor Contingency (2010 Dollars)		$20,875,711	$20,875,711
Total Balance of Plant (BOP) Direct Costs (2012 Dollars)		$118,537,729	$118,537,729
Balance of Plant (BOP) Equipment (2012 Dollars)		$24,816,321	$24,816,321
BOP Materials (2012 Dollars)		$26,464,135	$26,464,135
BOP Labor (2012 Dollars)		$67,257,273	$67,257,273
Balance of Plant (BOP) Indirect Costs (2012 Dollars)		$8,733,104	$8,733,104
Misc Contractor Labor (2012 Dollars)		$4,583,719	$4,583,719
Misc Contractor Labor (2010 Dollars)[2]		$4,115,000	$4,115,000
Entergy Internal Costs (2012 Dollars)		$20,076,644	$20,076,644
Entergy Internal Costs (2010 Dollars)[3]		$18,023,659	$18,023,659
Capital suspense (2010 Dollars)		$7,494,603	$7,494,603
Capital suspense (2012 Dollars)		$8,348,276	$8,348,276
CEPCI 2008		530.7	530.7
CEPCI 2010		533	533
CEPCI 2012 (January)		593.6	593.6
Total Capital Investment		$335,133,908	$335,133,908
Capital Recovery Factor (CRF)[4]		0.08	0.08
Annual Costs[5]			
CEPCI 2008		530.7	530.7
Direct Annual Costs (2012 Dollars)		$8,837,861	$8,859,823
Direct Annual Costs (2008 Dollars)		$7,901,369	$7,921,004
Operating Labor and Materials (2008 Dollars)		$4,287,845	$4,287,845
Water, Waste & Bag Replacement Costs $/MWh (2008 Dollars)		0.29	0.29
Lime Costs $/MWh (2008 Dollars)		0.75	0.75
Water, Waste, Bag Replacement and Lime Costs $/MWh (2008 Dollars)		1.04	1.04
Anticipated Yearly MWh[6]		3,474,543	3,493,423
Water, Waste, Bag Replacement and Lime Costs (2008 Dollars)		3,613,525	3,633,160
Indirect Annual Costs (IC) (2012 Dollars):		$43,290,224	$43,290,224
Overhead (2008 Dollars)	60% of total labor and materials costs	$2,572,707	$2,572,707
Overhead (2012 Dollars)		$2,877,631	$2,877,631
Administrative charges (2012 Dollars)	2% of TCI	$6,702,678	$6,702,678
Property Tax (2012 Dollars)	1% of TCI	$3,351,339	$3,351,339
Insurance (2012 Dollars)	1% of TCI	$3,351,339	$3,351,339
Capital recovery (2012 Dollars)	CRF* TCI	$27,007,236	$27,007,236
Total Annual Costs		$52,128,084	$52,150,047

1: The capital costs are based on contractor estimates provided by Sargent & Lundy (S&L) to Entergy in 2010 and other estimates compiled by Entergy in 2008. Both the 2010 cost from S&L and the 2008 cost estimated by Entergy were scaled to reflect 2012 dollars.

2: Misc contract labor includes permitting and regulatory support.

3: Entergy internal costs include labor, travel, and loader costs.

4: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr life, 7% interest

5: The O&M cost estimates are based on the Sargent & Lundy economic model from May 2008. The cost estimates were scaled to reflect 2012 dollars.

6: Anticipated yearly MWh = (944 MW/2 * anticipated annual operating hours) - 13 MWh, where 944 MW is anticipated EIA share for both boilers and 13 MWh is the estimated parsitic load loss estimate due to operation of the control from both boilers.

Wet Scrubber Capital and O&M Cost Estimate[1]			
Operational Data		**Unit 1**	**Unit 2**
Maximum HI (MMBtu/hr)		8950	8950
Annual Operating Hours, 2001-2003		7361	7401
Capital Costs		**Unit 1**	**Unit 2**
Total Equipment Costs (EC) (2012 Dollars)[2]		$150,037,000	$150,037,000
Purchased Equipment Cost (PEC)	PEC = 1.18 * EC	$177,043,660	$177,043,660
Total Capital Investment (TCI)		$389,496,052	$389,496,052
Capital Recovery Factor (CRF)(2012 Dollars)[3]		0.08	0.08
Annual Costs			
Direct Annual Costs (DC)[4] (2011 Dollars)		$15,734,500	$15,734,500
CECPI 2011		585.7	585.7
CECPI 2012 (January)		593.6	593.6
Direct Annual Costs (DC) (2012 Dollars)		$15,946,729	$15,946,729
Indirect Annual Costs (IC) (2012 Dollars)		$50,938,806	$50,938,806
Overhead (2011 Dollars)	60% of fixed labor and material costs from 2011 S&L conceptual costs	$2,987,400	$2,987,400
Overhead (2012 Dollars)		$3,027,694	$3,027,694
Administrative charges (2012 Dollars)	2% of TCI	$8,733,104	$8,733,104
Property Tax (2012 Dollars)	1% of TCI	$3,894,961	$3,894,961
Insurance (2012 Dollars)	1% of TCI	$3,894,961	$3,894,961
Capital recovery	CRF* TCI	$31,388,086	$31,388,086
Total Annual Costs		$66,885,535	$66,885,535

1: The costing method is modeled after the cost method summarized in Section 5.2 of the EPA Control Cost Manual (Post-Combustion Controls, Chapter 1 - Wet Scrubbers for Acid Gas, Table 1.3). Costs for capital suspense have been accounted for and added to the TCI calculated using the Cost Control Manual.

2: The total equipment cost is the sum of the equipment and material costs from the November 30, 2012 Sargent & Lundy conceptual cost estimate.

3: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr life, 7% interest

4: The direct costs include the fixed O&M from the S&L 2011 conceptual costs (operating labor, operating materials, and maintenance materials) plus variable O&M from the S&L 2011 conceptual costs (aux power, bags, cages, lime, limestone, and water)

LNB-SOFA Capital and O&M Cost Estimate		
Operational Data	**Unit 1**	**Unit 2**
Maximum HI (MMBtu/hr)	8950	8950
Annual Operating Hours, 2001-2003	7361	7401
Capital Costs	**Unit 1**	**Unit 2**
Installed Capital Cost[1]	10,461,206	14,488,206
Capital Recovery Factor (CRF)[2]	0.08	0.08
Annual Costs	**Unit 1**	**Unit 2**
Fixed O&M Costs[3]	142,000	142,000
Variable O&M Costs[4]	177,887	170,838
Annualized Capital Cost	843,031	1,167,552
Total Annual Costs	1,162,918	1,480,391

1: The installed capital cost estimates for LNB/OFA are based on the installed capital cost estimates for each unit as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study (Unit 1 = $7,804,000 and Unit 2 = $11,831,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500 for each unit), cost for Entergy employee labor and loaders (estimated by Entergy to be $1,589,033 for each unit), and cost for capital suspense (estimated by Entergy to be $955,673 for each unit) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimates were provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study

4: The variable O&M costs are based on the Eastern Research Group report "Analysis of Combustion Controls for Reducing NOx Emissions from Coal-fired EGUs in the WRAP Region" September 6, 2005. Section 4.3.1 and Appendix D.

Variable O&M = (0.027 mills/kW-hr/1000) x (1 kW-hr/10,000 Btu) x H x C x 10^6 Btu/mmBtu

Where:
H = Annual operating hours
C = Boiler design capacity (mmBtu/hr)
Note: The variable rate used for variable O&M costs was 0.027 mills/kW-hr. This is the rate listed in Appendix D

LNB-SOFA + SNCR Capital and O&M Cost Estimate

Operational Data	Unit 1	Unit 2
Maximum HI (MMBtu/hr)	8950	8950
Annual Operating Hours, 2001-2003	7361	7401
Capital Costs	**Unit 1**	**Unit 2**
Installed Capital Cost [1]	21,371,325	25,398,325
Capital Recovery Factor (CRF)[2]	0.08	0.08
Annual Costs	**Unit 1**	**Unit 2**
Fixed O&M Costs[3]	311,000	311,000
Variable O&M Costs[4]	4,538,000	4,542,000
Annualized Capital Cost	1,722,238	2,046,760
Total Annual Costs	6,571,238	6,899,760

1: The installed capital cost estimates for LNB/OFA + SNCR are based on the installed capital cost estimates for each unit as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study (Unit 1 = $16,290,000 and Unit 2 = $20,317,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $112,500 for each unit), cost for Entergy employee labor and loaders (estimated by Entergy to be $3,223,396 for each unit), and cost for capital suspense (estimated by Entergy to be $1,745,429 for each unit) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life
Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study.

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SNCR makes the variable O&M costs less than that of SNCR alone due to a lower NOx concentration and resulting less reagent usage.

LNB-SOFA + SCR Capital and O&M Cost Estimate

Operational Data	**Unit 1**	**Unit 2**
Maximum HI (MMBtu/hr)	8950	8950
Annual Operating Hours, 2001-2003	7361	7401
Capital Costs[1]	**Unit 1**	**Unit 2**
Installed Capital Cost	230,329,138	206,747,898
Capital Recovery Factor (CRF)[2]	0.08	0.08
Annual Costs[3]	**Unit 1**	**Unit 2**
Fixed O&M Costs	608,000	608,000
Variable O&M Costs	2,836,000	2,858,000
Annualized Capital Cost	18,561,397	16,661,070
Total Annual Costs	22,005,397	20,127,070

1: The installed capital cost estimates for LNB/OFA + SCR are based on the installed capital cost estimates for each unit as provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study (Unit 1 = $202,601,000 and Unit 2 = $178,240,000) plus additional cost not accounted for in the S&L cost estimate, including cost for permitting and legal/regulatory support (estimated by Entergy to be $450,000 for each unit), cost for Entergy employee labor and loaders (estimated by Entergy to be $6,725,610 for each unit), and cost for capital suspense (estimated by Entergy to be $20,552,528 for Unit 1 and $21,332,288 for Unit 2) .

2: CRF = [I x (1+i)^a]/[(1+i)^a - 1], where I = interest rate, a = equipment life

Equipment CRF, 30-yr actual service life, 7% interest

3: The fixed O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study.

4: The variable O&M cost estimates are based on the cost estimates provided by Sargent & Lundy in the 5/16/2013 NOx Control Technology Cost and Performance Study. Adding LNB/OFA to SCR makes the variable O&M costs less than that of SCR alone due to a lower NOx concentration and resulting less reagent usage.

APPENDIX B

BASELINE VISIBILITY IMPAIRMENT BY POLLUTANT

The following tables are a continuation of the information presented in Tables 4-2 through 4-4. Tables B-1 through B-3 shows the delta deciview by pollutant in a percentage format.

TABLE B-1. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-01 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with $\Delta dv \geq 0.5$	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	2.956	1.628	41	79.06	20.65	0.16	0.12
2002	2.111	1.386	30	47.73	47.56	0.82	3.90
2003	4.194	1.13	35	63.88	34.05	0.30	1.76
Upper Buffalo Wilderness							
2001	2.339	1.128	34	74.05	25.72	0.23	0.00
2002	1.544	0.818	18	83.19	16.22	0.34	0.26
2003	1.900	1.140	25	97.99	1.80	0.22	0.00
Hercules Glades Wilderness							
2001	1.737	1.041	28	92.29	7.51	0.21	0.00
2002	1.288	0.617	13	78.93	20.76	0.23	0.08
2003	2.230	0.786	20	88.91	10.87	0.21	0.00
Mingo Wilderness							
2001	1.569	0.887	18	93.36	6.03	0.33	0.28
2002	1.012	0.750	24	56.89	42.59	0.25	0.28
2003	1.114	0.702	14	63.85	34.84	0.38	0.94

TABLE B-2. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-02 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with $\Delta dv \geq 0.5$	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	3.199	1.695	41	76.22	23.49	0.16	0.14
2002	2.270	1.481	33	65.10	31.38	0.73	2.80
2003	4.437	1.169	38	50.94	47.45	0.31	1.31
Upper Buffalo Wilderness							
2001	2.385	1.185	35	70.85	28.92	0.23	0.00
2002	1.618	0.846	20	80.92	18.47	0.31	0.30
2003	1.998	1.176	25	81.45	18.30	0.24	0.00
Hercules Glades Wilderness							
2001	1.838	1.060	30	91.12	8.68	0.20	0.00
2002	1.340	0.643	14	76.19	23.50	0.21	0.09
2003	2.263	0.806	21	87.28	12.51	0.21	0.00
Mingo Wilderness							
2001	1.701	0.903	18	92.36	6.99	0.31	0.33
2002	1.031	0.805	25	83.70	16.04	0.22	0.03
2003	1.150	0.750	14	60.22	38.39	0.35	1.04

TABLE B-3. BASELINE VISIBILITY IMPAIRMENT ATTRIBUTABLE TO SN-05 BY POLLUTANT

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Day with $\Delta dv \geq 0.5$	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek Wilderness							
2001	0.028	0.008	0	12.12	82.96	1.17	2.01
2002	0.020	0.005	0	13.56	82.08	0.17	3.94
2003	0.036	0.010	0	15.90	76.81	1.12	4.55
Upper Buffalo Wilderness							
2001	0.014	0.004	0	18.99	77.59	1.36	0.12
2002	0.009	0.004	0	22.05	75.33	1.01	0.12
2003	0.013	0.005	0	17.05	74.39	1.76	4.31
Hercules Glades Wilderness							
2001	0.007	0.004	0	15.47	80.65	0.89	1.68
2002	0.006	0.003	0	30.17	65.62	1.50	0.49
2003	0.008	0.004	0	60.26	33.74	2.40	0.03
Mingo Wilderness							
2001	0.009	0.003	0	12.83	84.94	0.89	0.06
2002	0.019	0.008	0	11.22	84.34	1.02	1.91
2003	0.015	0.003	0	21.56	77.36	0.43	0.05

APPENDIX C

CALMET MODELING PROTOCOL

As stated in Section 3.1, the meteorological data used in the analyses presented in this report was originally developed in 2007 and was first used in a BART determination for Oklahoma Gas & Electric. Because the development of a set of CALMET/CALPUFF meteorological data is so intensive, this same dataset has been used numerous times since 2007 for various other BART projects in EPA Region 6. The protocol that accompanied the original development has followed the dataset in each case and is doing so here again.

CALMET DATA PROCESSING PROTOCOL ▲ BART DETERMINATION
OKLAHOMA GAS & ELECTRIC

MUSKOGEE GENERATING STATION
SEMINOLE GENERATING STATION
SOONER GENERATING STATION

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Project 083701.0004

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1. INTRODUCTION

Oklahoma Gas & Electric (OG&E) owns and operates three electric generating stations near Muskogee, Oklahoma (Muskogee Generating Station), Seminole, Oklahoma (Seminole Generating Station), and Stillwater, Oklahoma (Sooner Generating Station). These generating stations are considered eligible to be regulated under the U.S. Environmental Protection Agency's (EPA) Best Available Retrofit Technology (BART) provisions of the Regional Haze Rule. This protocol describes the proposed methodology for conducting the CALMET data processing for the refined CALPUFF BART modeling analysis for OG&E's Muskogee, Seminole, and Sooner Generating Stations. A detailed CALPUFF BART modeling protocol will be submitted in the near future and will include a discussion of the CALPUFF parameters as well as the post processing methodologies to be used in the refined modeling analysis for each station.

1.1 BEST AVAILABLE RETROFIT TECHNOLOGY RULE BACKGROUND

On July 1, 1999, the U.S. Environmental EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to improve visibility in 156 specific areas across with United States, known as Class I areas. The Clean Air Act defines Class I areas as certain national parks (over 6000 acres), wilderness areas (over 5000 acres), national memorial parks (over 5000 acres), and international parks that were in existence on August 7, 1977.

On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the BART rule, which included guidance for making source-specific Best Available Retrofit Technology (BART) determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962 and August 7, 1977, and
(3) Are listed as one of the 26 listed source categories in the guidance.

A BART-eligible source is not automatically subject to BART. Rather, BART-eligible sources are subject-to-BART if the sources are "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." EPA has determined that sources are reasonably anticipated to cause or contribute to visibility impairment if the visibility impacts from a source are greater than 0.5 deciviews (dv) when compared against a natural background.

Air quality modeling is the tool that is used to determine a source's visibility impacts. States have the authority to exempt certain BART-eligible sources from installing BART controls if the results of the dispersion modeling demonstrate that the source cannot reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. Further, states also have the authority to define the modeling procedures for conducting modeling related to making BART determinations.

1.2 OBJECTIVE

The objective of this document is to provide a protocol summarizing the modeling methods and procedures that will be followed to conduct the CALMET data processing necessary to complete a refined CALPUFF modeling analysis for the OG&E generating stations discussed above. The modeling methods and procedures contained in this protocol and the CALPUFF protocol yet to be submitted will be used to determine appropriate controls for OG&E'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. It is OG&E's intent to determine a combination of emissions controls that will reduce the impact of each generating station to a degree that the 98th percentile of the visibility impact predicted by the model due to all the BART eligible sources at each station collectively is below EPA's recommended visibility contribution threshold of 0.5 Δdv.

1.3 LOCATION OF SOURCES AND RELEVANT CLASS I AREAS

The sources listed in Table 1-1 are the sources that have been identified by OG&E as sources that meet the three criteria for BART-eligible sources.

TABLE 1-1. BART-ELIGIBLE SOURCES

EPN	Description
	Muskogee Sources
Unit 4	5,480 MMBtu/hr Coal Fired Boiler
Unit 5	5,480 MMBtu/hr Coal Fired Boiler
	Seminole Sources
SM1	5,480 MMBtu/hr Natural Gas Fired Boiler
SM2	5,480 MMBtu/hr Natural Gas Fired Boiler
SM3	5,496 MMBtu/hr Natural Gas Fired Boiler
	Sooner Sources
Unit 1	5,116 MMBtu/hr Coal Fired Boiler
Unit 2	5,116 MMBtu/hr Coal Fired Boiler

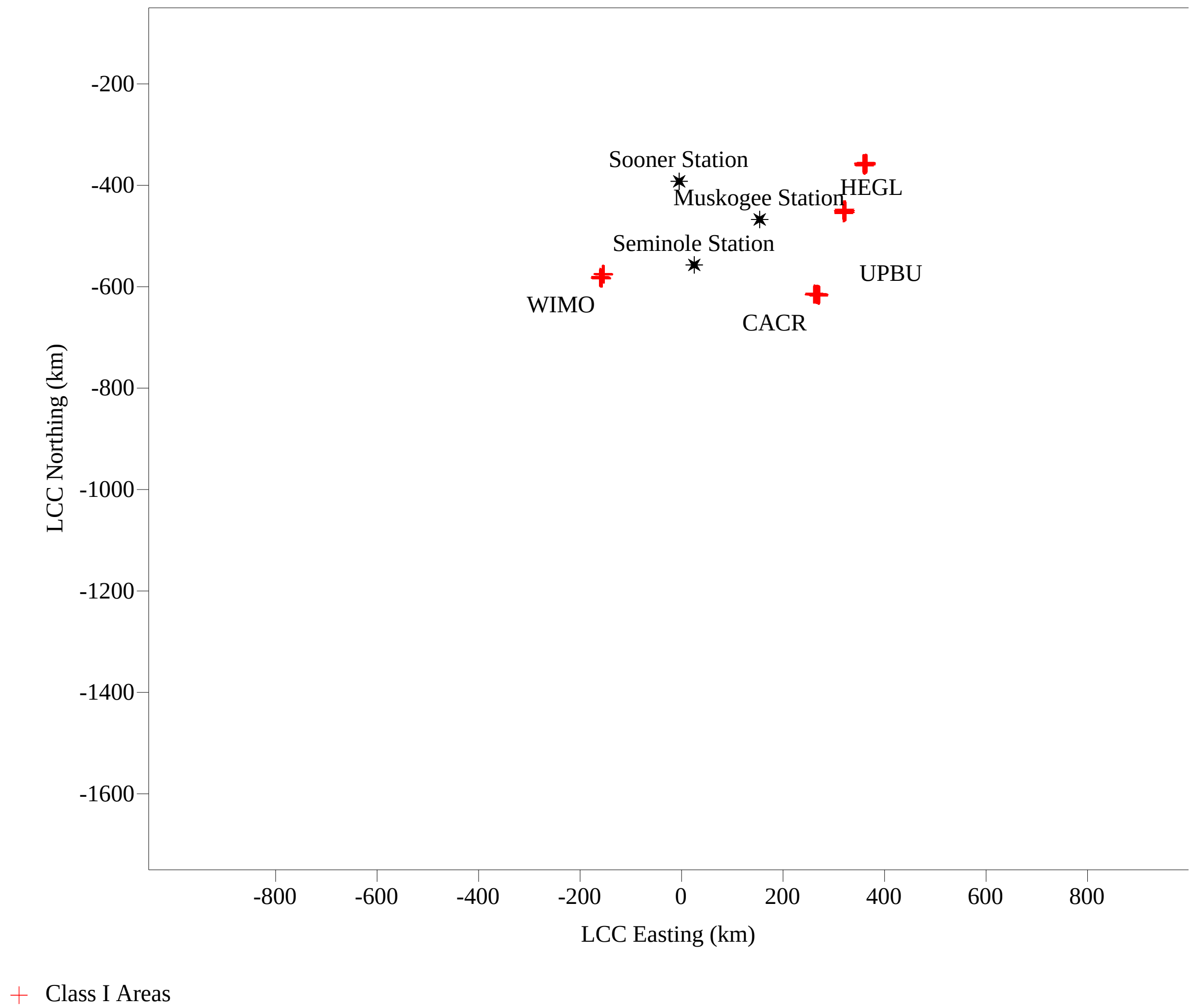
As required in CENRAP's BART Modeling Guidelines, Class I areas within 300 km of each station will be included in each analysis. The following table summarizes the distances of the four closest Class I areas to each station. As seen from this summary, some Class I areas are more than 300 km from the certain stations. However, in order to demonstrate that each station will not have an adverse effect on the visibility at any of the four nearest Class I areas, OG&E has opted to include those Class I areas more than 300 km away in this analysis. Note that the distances listed in the table below are the distances between the stations and the closest border of the Class I areas.

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

	CACR	HEGL	UPBU	WIMO
Muskogee	180	230	164	324
Seminole	242	386	310	178
Sooner	345	363	327	234

A plot of the Class I areas with respect to the each station is provided in Figure 1-1.

FIGURE 1-1. PLOT OF SOURCES AND NEAREST CLASS I AREAS



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.

2.1 MODEL VERSIONS

The versions of the CALPUFF modeling system programs that are proposed for conducting OG&E’s BART modeling are listed in Table 2-1. A detailed refined CALPUFF BART modeling protocol will be submitted in the near future.

TABLE 2-1. CALPUFF MODELING SYSTEM VERSIONS

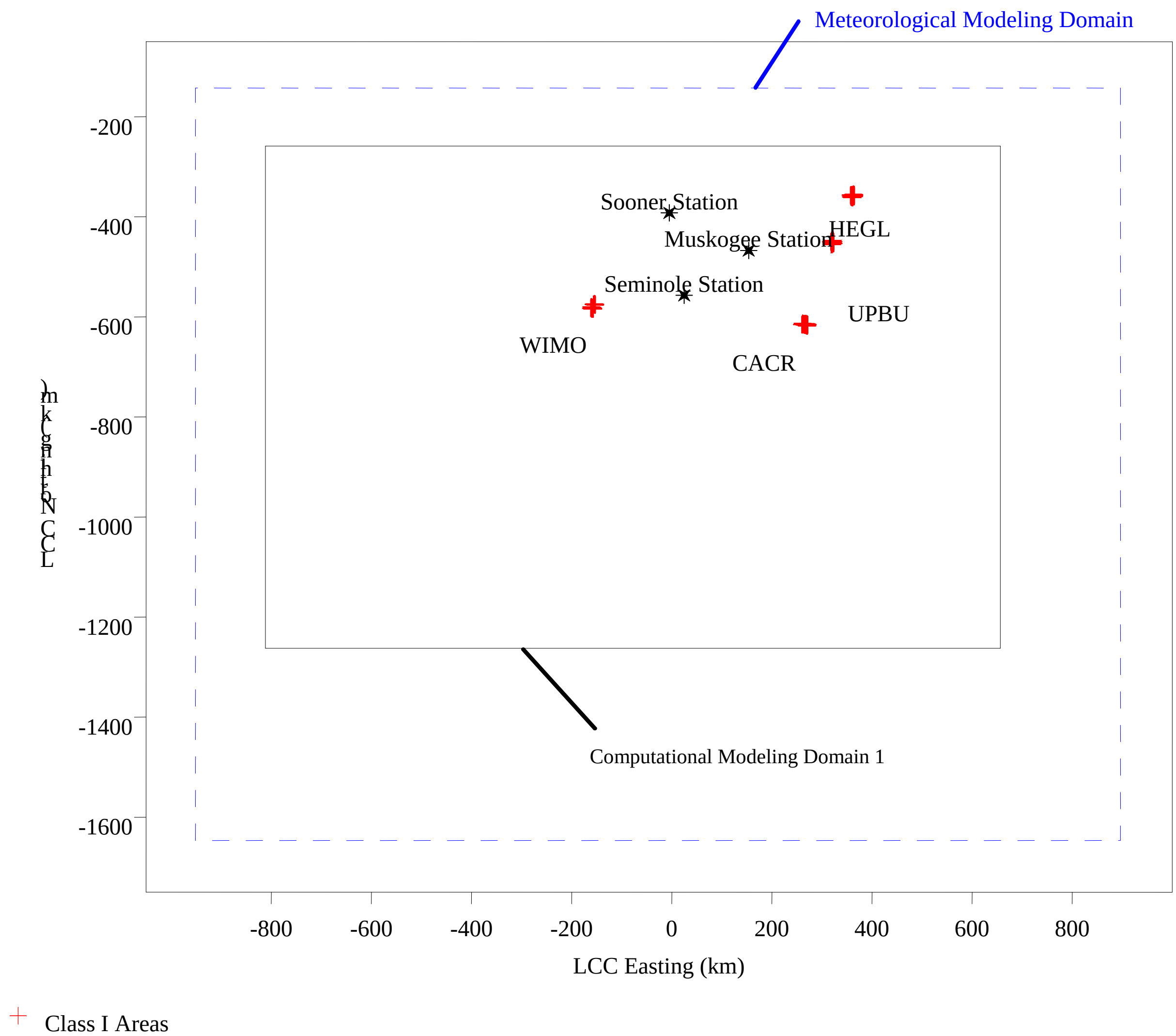
Processor	Version	Level
TERREL	3.3	030402
CTGCOMP	2.21	030402
CTGPROC	2.63	050128
MAKEGEO	2.2	030402
CALMET	5.53a	040716
CALPUFF	5.8	070623
POSTUTIL	1.3	030402
CALPOST	5.51	030709

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 proposed meteorological modeling domain with respect to the Class I areas being modeled is also provided in

Figure 2-1. The computational domain will be set to extend at least 50 km in all directions beyond the Muskogee, Seminole, and Sooner Generating Stations 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.

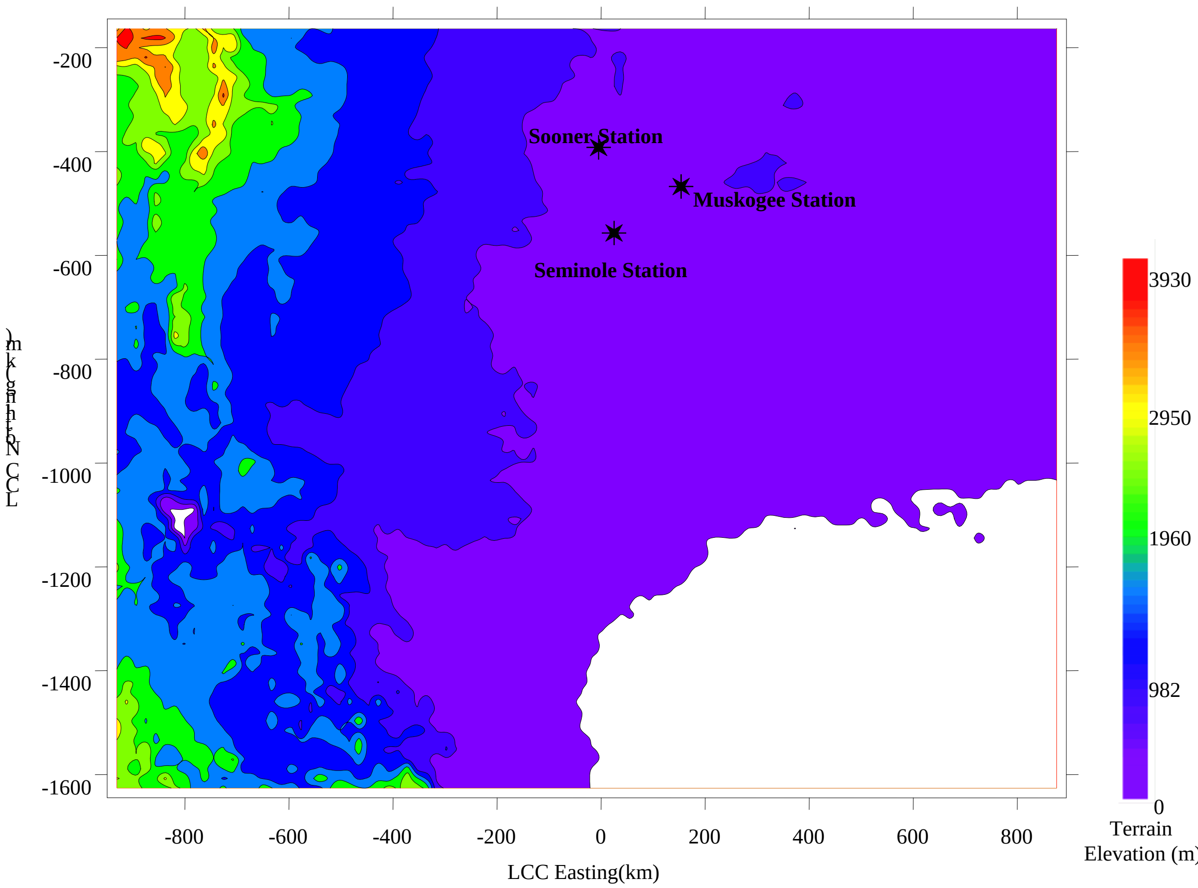
3.1 GEOPHYSICAL DATA

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 be 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.

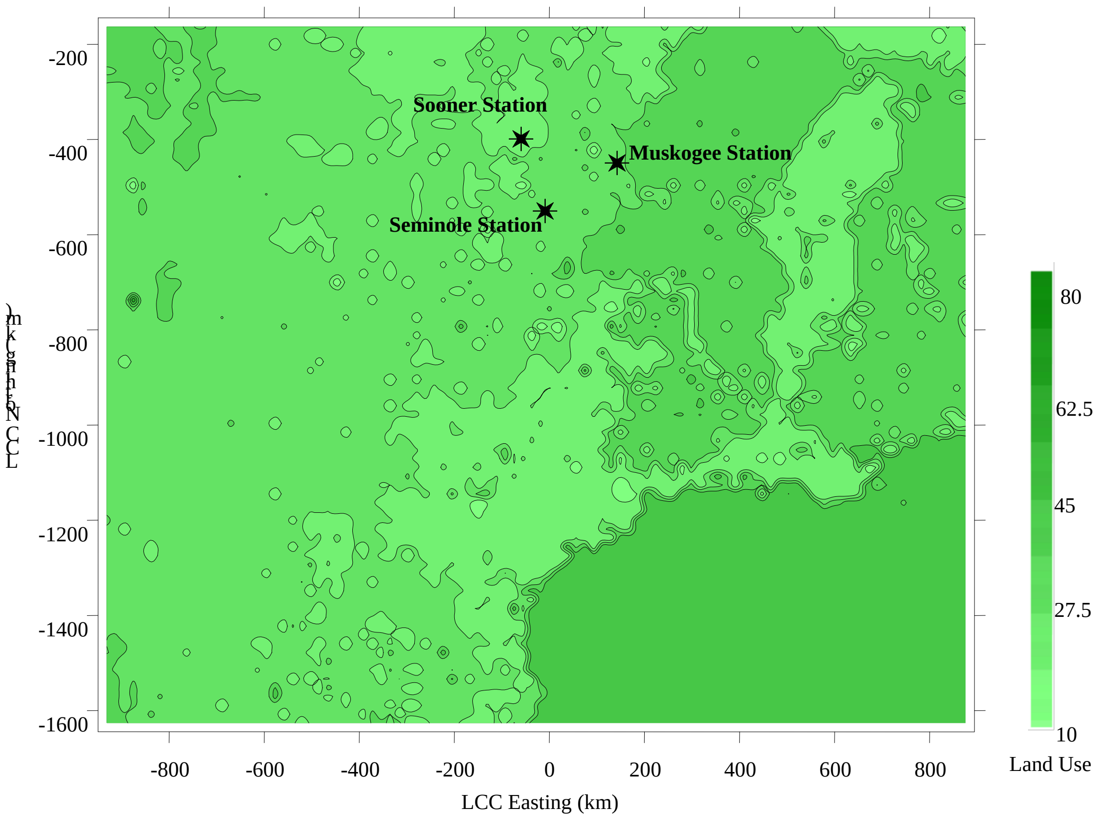
FIGURE 3-1. PLOT OF LAND ELEVATION USING USGS TERRAIN DATA



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 will generate 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 OG&E'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. TXI 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.

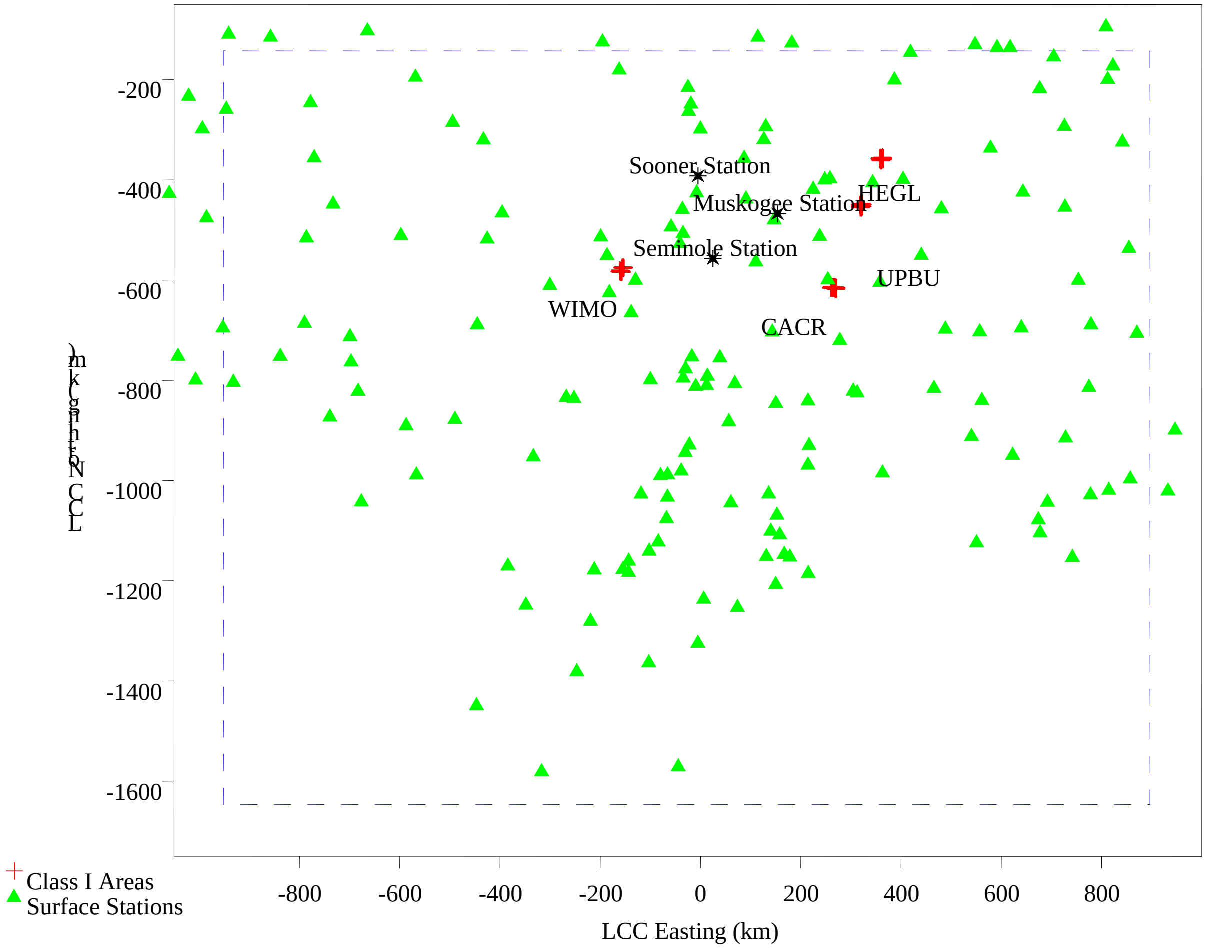
The time periods covered by the data in each of the MM5 files extracted by Alpine Geophysics include a specific number of calendar days, where the data starts at Hour 0 in GMT for the first calendar day and ends at Hour 23 in GMT on the last calendar day. In order to run CALMET in the local standard 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 OG&E'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.

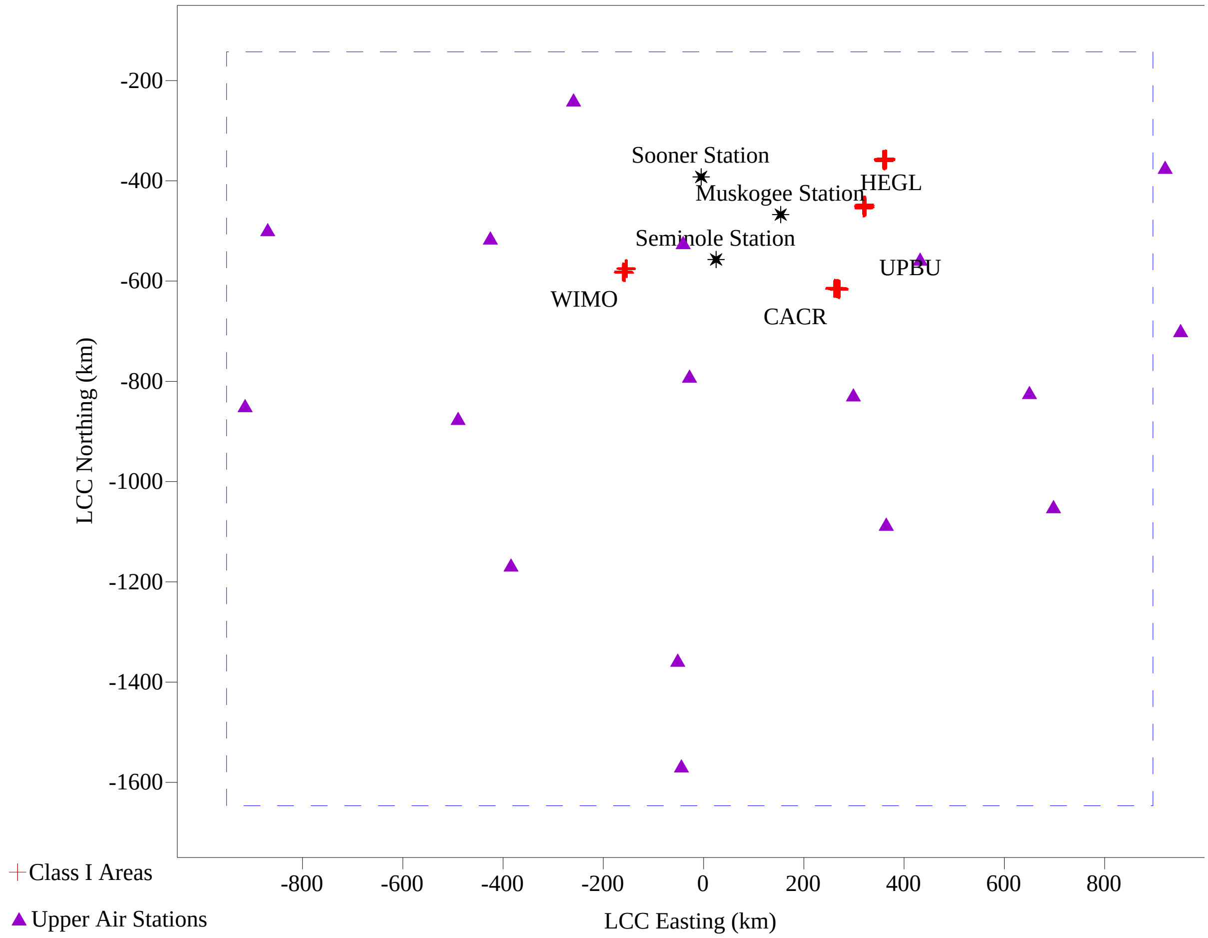
FIGURE 3-3. PLOT OF SURFACE STATION LOCATIONS



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.

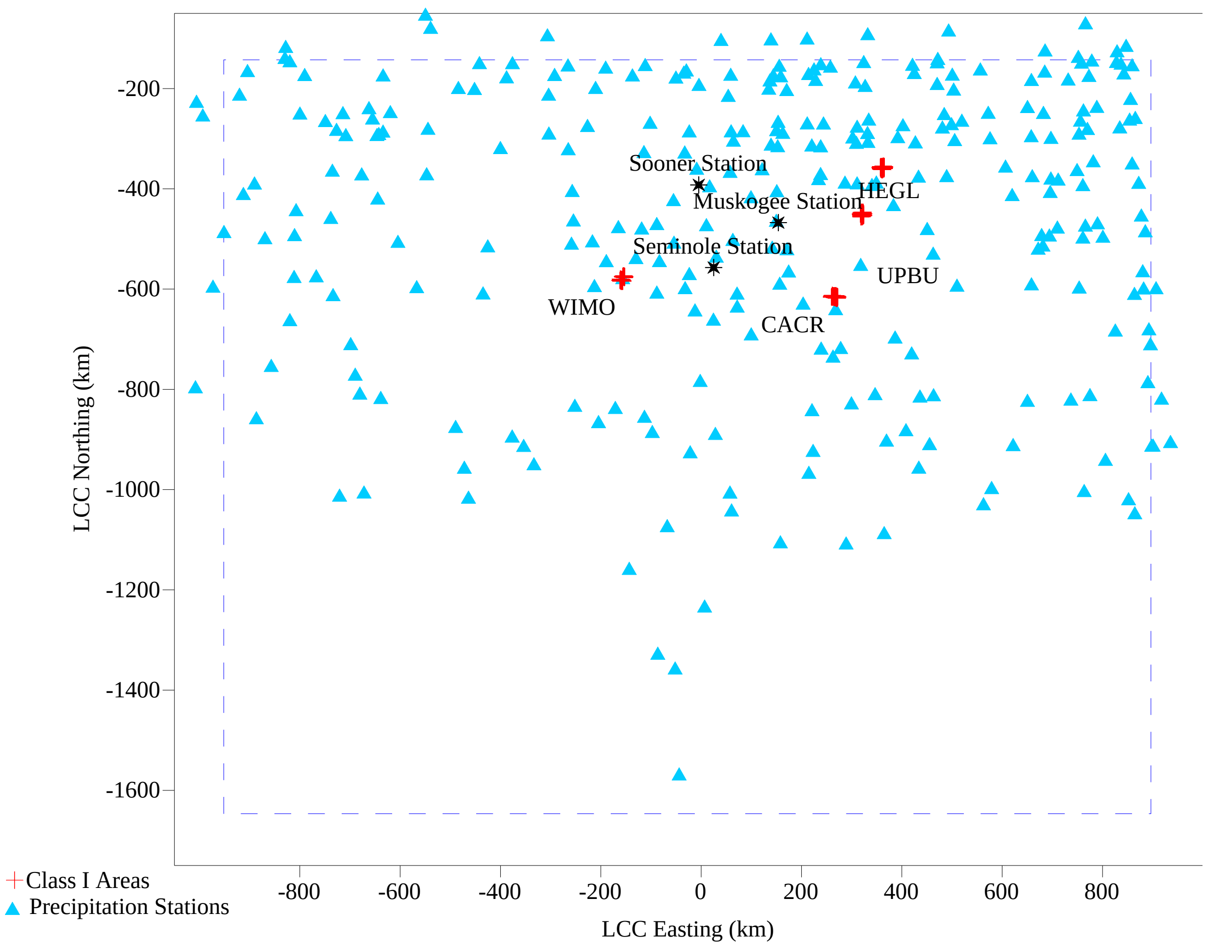
FIGURE 3-4. PLOT OF UPPER AIR STATIONS LOCATIONS



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.

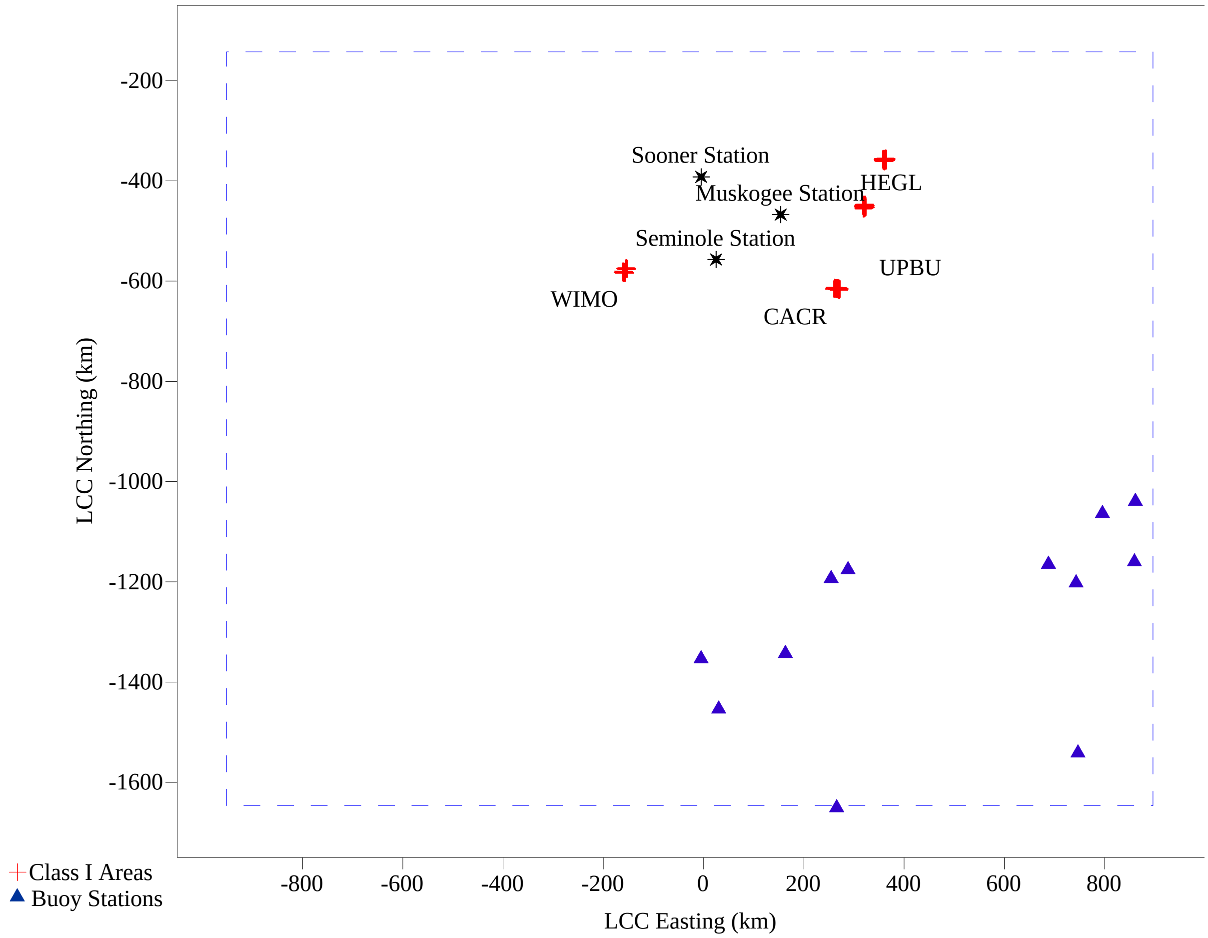
FIGURE 3-5. PLOT OF PRECIPITATION METEOROLOGICAL STATIONS



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

Appendix B provides a sample CALMET input file used in OG&E's modeling analysis. A few details of the CALMET model setup for sensitive parameters are also 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.

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
83	KTCS	72271	-952.353	-695.469	96.9888	39.9937

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
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
127	KEHR	72423	812.573	-199.695	97.0096	39.9982
128	KEVV	93817	822.929	-172.715	97.0097	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
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
38	SAGU	57337	-790.269	-176.061	96.9907	39.9984

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
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
78	COLU	141740	220.541	-316.555	97.0026	39.9971

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
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
118	PADU	156110	753.185	-293.024	97.0089	39.9974

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
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
158	MCES	235415	471.737	-143.942	97.0056	39.9987

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
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
198	ROY	297638	-644.735	-422.422	96.9924	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
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
238	TULS	348992	99.361	-419.873	97.0012	39.9962

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
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
278	NAVA	416210	28.358	-892.028	97.0003	39.9919

Number	Station Acronym	Station ID	LCC East (km)	LCC North (km)	Long	Lat
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

APPENDIX D

CEMS DATA FROM CAMD FOR 2001 TO 2003 AND 2009 TO 2011

Unit ID	Date	SO2 (tons)	Heat Input (MMBtu)
1	1/5/2001	1.427	26,054
1	1/6/2001	42.883	149,330
1	1/7/2001	68.245	194,455
1	1/8/2001	63.914	182,770
1	1/9/2001	67.859	204,772
1	1/10/2001	65.955	190,485
1	1/11/2001	70.031	202,920
1	1/12/2001	56.743	187,273
1	1/13/2001	64.013	207,805
1	1/14/2001	48.542	144,623
1	1/15/2001	67.075	192,264
1	1/16/2001	57.886	185,487
1	1/17/2001	68.777	198,849
1	1/18/2001	62.858	188,091
1	1/19/2001	58.119	185,976
1	1/20/2001	66.6	191,109
1	1/21/2001	69.856	206,742
1	1/22/2001	65.144	190,490
1	1/23/2001	64.994	194,193
1	1/24/2001	56.804	182,694
1	1/25/2001	63.27	202,127
1	1/26/2001	55.296	171,617
1	4/3/2001	0.547	6,873
1	4/4/2001	1.055	8,573
1	4/5/2001	1.546	10,088
1	4/6/2001	8.967	38,007
1	4/7/2001	6.478	26,784
1	4/9/2001	5.976	26,103
1	4/10/2001	24.207	93,161
1	4/11/2001	55.76	174,874
1	4/12/2001	59.522	173,490
1	4/13/2001	54.427	165,840
1	4/14/2001	58.422	171,216
1	4/15/2001	24.188	72,680
1	4/16/2001	2.533	10,525
1	4/17/2001	56.651	164,701
1	4/18/2001	64.409	164,695
1	4/19/2001	61.953	160,949
1	4/20/2001	63.59	173,481
1	4/21/2001	31.694	94,929
1	4/22/2001	59.626	164,679
1	4/23/2001	43.525	120,867
1	4/24/2001	9.105	28,862
1	4/25/2001	62.678	180,855
1	4/26/2001	49.349	140,127

1	4/27/2001	62.261	187,109
1	4/28/2001	62.59	179,852
1	4/29/2001	52.9	155,338
1	4/30/2001	69.128	180,489
1	5/1/2001	49.114	136,478
1	5/2/2001	63.29	182,498
1	5/3/2001	62.078	184,546
1	5/4/2001	63.607	185,637
1	5/5/2001	60.206	174,287
1	5/6/2001	55.887	164,969
1	5/7/2001	66.414	181,665
1	5/8/2001	66.104	187,835
1	5/9/2001	61.648	183,461
1	5/10/2001	61.171	181,272
1	5/11/2001	57.942	172,097
1	5/12/2001	5.656	17,561
1	5/13/2001	0.609	3,950
1	5/14/2001	55.397	159,810
1	5/15/2001	64.475	183,212
1	5/16/2001	63.77	181,857
1	5/17/2001	59.676	176,776
1	5/18/2001	61.378	176,568
1	5/19/2001	64.114	180,838
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1	5/21/2001	50.906	148,628
1	5/22/2001	52.519	154,556
1	5/23/2001	58.172	170,287
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1	5/26/2001	60.789	175,004
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1	5/28/2001	64.869	174,922
1	5/29/2001	60.546	180,550
1	5/30/2001	59.685	173,119
1	5/31/2001	55.194	161,952
1	6/1/2001	56.076	161,968
1	6/2/2001	62.356	179,767
1	6/3/2001	62.691	187,445
1	6/4/2001	69.826	195,288
1	6/5/2001	65.276	187,650
1	6/6/2001	62.966	184,410
1	6/7/2001	62.048	178,041
1	6/8/2001	70.887	192,530
1	6/9/2001	59.876	178,409
1	6/10/2001	58.98	177,831
1	6/11/2001	61.296	185,722
1	6/12/2001	68.818	196,712

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1	6/15/2001	72.149	202,380
1	6/16/2001	69.886	199,793
1	6/17/2001	71.396	201,210
1	6/18/2001	75.678	217,184
1	6/19/2001	69.793	203,565
1	6/20/2001	70.83	204,866
1	6/21/2001	69.739	203,174
1	6/22/2001	69.941	208,054
1	6/23/2001	67.056	193,075
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1	6/25/2001	62.686	186,522
1	6/26/2001	68.046	197,197
1	6/27/2001	59.758	173,545
1	6/28/2001	69.789	201,036
1	6/29/2001	71.015	199,606
1	6/30/2001	67.63	196,607
1	7/1/2001	64.938	190,313
1	7/2/2001	67.968	201,234
1	7/3/2001	74.092	198,062
1	7/4/2001	68.436	197,642
1	7/5/2001	67.987	196,138
1	7/6/2001	65.934	200,553
1	7/7/2001	67.562	194,432
1	7/8/2001	61.583	219,889
1	7/9/2001	59.883	204,470
1	7/10/2001	83.794	215,984
1	7/11/2001	67.369	194,599
1	7/12/2001	64.477	189,174
1	7/13/2001	7.831	34,051
1	7/14/2001	68.11	194,471
1	7/15/2001	69.282	181,728
1	7/16/2001	70.182	195,428
1	7/17/2001	56.916	200,084
1	7/18/2001	67.033	211,803
1	7/19/2001	67.091	201,315
1	7/20/2001	79.587	213,335
1	7/21/2001	67.74	202,185
1	7/22/2001	70.121	207,400
1	7/23/2001	58.683	178,725
1	7/24/2001	57.098	206,917
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1	7/26/2001	70.82	217,541
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1	8/7/2001	57.665	191,653
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1	8/9/2001	47.023	193,280
1	8/10/2001	58.4	208,250
1	8/11/2001	48.012	184,435
1	8/12/2001	60.14	189,596
1	8/13/2001	57.645	181,656
1	8/14/2001	58.304	186,898
1	8/15/2001	58.225	180,890
1	8/16/2001	71.981	214,532
1	8/17/2001	64.94	198,444
1	8/18/2001	67.218	203,643
1	8/19/2001	67.619	192,562
1	8/20/2001	65.533	194,140
1	8/21/2001	62.648	196,979
1	8/22/2001	68.512	199,137
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1	9/14/2001	65.662	199,431

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1	9/20/2001	59.628	188,047
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1	9/25/2001	58.935	173,197
1	9/26/2001	58.448	172,509
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1	12/27/2001	64.214	194,709
1	12/28/2001	64.287	192,369
1	12/29/2001	61.542	192,964
1	12/30/2001	65.491	212,269
1	12/31/2001	47.421	191,796
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1	1/7/2002	62.917	197,310
1	1/8/2002	54.84	171,604
1	1/9/2002	53.326	171,734
1	1/10/2002	63.441	195,374
1	1/11/2002	62.568	188,959
1	1/12/2002	68.436	202,097
1	1/13/2002	63.656	186,189
1	1/14/2002	74.083	201,801
1	1/15/2002	66.62	197,855
1	1/16/2002	73.726	214,133
1	1/17/2002	64.49	192,439
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1	1/22/2002	55.559	176,106
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1	1/24/2002	50.749	160,297
1	1/25/2002	61.775	193,282
1	1/26/2002	61.535	197,676
1	1/27/2002	56.132	180,536
1	1/28/2002	64.414	181,611
1	1/29/2002	64.231	189,953
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1	2/9/2002	66.066	207,388

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1	2/27/2002	64.448	206,536
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1	3/4/2002	62.583	191,590
1	3/5/2002	70.861	214,707
1	3/6/2002	64.212	203,299
1	3/7/2002	70.486	214,514
1	3/8/2002	61.141	186,812
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1	4/15/2002	57.024	166,491
1	4/16/2002	53.047	171,720
1	4/17/2002	53.468	175,834
1	4/18/2002	43.8	166,016
1	4/19/2002	48.83	175,977
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1	4/22/2002	38.239	113,983
1	4/23/2002	68.634	190,260
1	4/24/2002	63.012	191,729
1	4/25/2002	63.787	197,983
1	4/26/2002	59.158	185,084
1	4/27/2002	69.829	199,244
1	4/28/2002	69.214	186,436
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1	5/9/2002	66.113	182,139
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1	5/11/2002	35.014	116,084
1	5/12/2002	54.48	161,097
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1	5/15/2002	67.13	216,015
1	5/16/2002	61.757	191,148
1	5/19/2002	19.888	74,291
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1	5/22/2002	64.735	186,565
1	5/23/2002	58.363	168,141
1	5/24/2002	68	192,062
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1	5/26/2002	65.7	186,889
1	5/27/2002	68.492	186,964
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1	5/29/2002	66.227	185,455
1	5/30/2002	68.742	196,710
1	5/31/2002	64.839	187,781
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1	6/4/2002	70.507	189,222
1	6/5/2002	78.176	213,694
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1	6/7/2002	67.76	201,030
1	6/8/2002	65.933	190,291
1	6/9/2002	66.485	191,411
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1	6/12/2002	65.373	188,944
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1	6/15/2002	64.898	184,036
1	6/16/2002	56.896	167,608
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1	6/18/2002	63.102	186,073
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1	6/20/2002	79.393	189,472
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1	6/29/2002	68.421	186,719
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1	7/3/2002	67.705	216,727
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1	7/8/2002	59.271	194,915
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1	7/17/2002	67.856	189,957
1	7/18/2002	72.426	186,966
1	7/19/2002	73.675	189,888
1	7/20/2002	69.983	185,830
1	7/21/2002	76.773	205,421
1	7/22/2002	68.664	191,286
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1	7/28/2002	69.506	215,790
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1	8/12/2002	62.398	172,804
1	8/13/2002	68.958	187,693
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1	8/15/2002	70.911	202,259
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1	8/17/2002	75.284	205,494
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1	8/22/2002	66.974	195,545
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1	8/29/2002	72.557	207,110
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1	9/9/2002	62.599	188,709
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1	9/27/2002	62.503	181,676
1	9/28/2002	77.516	198,966
1	9/29/2002	68.433	180,931
1	9/30/2002	71.244	201,058
1	10/1/2002	64.037	177,954
1	10/2/2002	72.814	198,480
1	10/3/2002	68.824	180,764
1	10/4/2002	74.934	200,236
1	10/5/2002	66.208	182,168
1	10/6/2002	65.293	206,104
1	10/7/2002	57.704	184,131
1	10/8/2002	70.366	165,991
1	10/9/2002	68.841	174,546
1	10/10/2002	72.823	205,605
1	10/11/2002	62.789	196,835
1	10/12/2002	67.896	219,518
1	10/13/2002	64.469	192,609
1	10/14/2002	76.585	209,355
1	10/15/2002	61.276	184,644
1	10/16/2002	63.876	190,268
1	10/17/2002	63.739	178,031
1	10/18/2002	71.555	196,906
1	10/19/2002	65.951	179,201
1	10/20/2002	69.229	184,225
1	10/21/2002	67.223	172,452
1	10/22/2002	68.757	200,912
1	10/23/2002	66.493	181,742
1	10/24/2002	77.876	197,936
1	10/25/2002	66.975	188,079
1	10/26/2002	72.399	203,780
1	10/27/2002	23.99	74,983
1	10/28/2002	54.183	149,783
1	10/29/2002	62.737	145,898
1	10/30/2002	50.869	128,978
1	10/31/2002	70.349	186,719
1	11/1/2002	67.923	185,442
1	11/2/2002	59.053	158,260
1	11/3/2002	63.912	177,005
1	11/4/2002	67.24	179,065
1	11/5/2002	74.584	200,208
1	11/6/2002	59.928	179,634
1	11/7/2002	72.689	196,407
1	11/8/2002	67.716	178,329
1	11/9/2002	77.283	191,726

1	11/10/2002	63.848	171,424
1	11/11/2002	72.94	193,090
1	11/12/2002	61.283	167,255
1	11/13/2002	69.047	188,017
1	11/14/2002	65.669	178,330
1	11/15/2002	73.693	194,656
1	11/16/2002	66.131	172,077
1	11/17/2002	69.205	194,371
1	11/18/2002	63.507	172,577
1	11/19/2002	71.279	187,306
1	11/20/2002	57.233	149,545
1	11/22/2002	0.285	2,467
1	11/23/2002	43.397	119,570
1	11/24/2002	70.071	193,889
1	11/25/2002	65.963	178,921
1	11/26/2002	65.652	192,450
1	11/27/2002	70.457	162,879
1	11/28/2002	64.064	161,891
1	11/29/2002	46.986	123,508
1	11/30/2002	64.959	169,536
1	12/1/2002	66.605	169,543
1	12/2/2002	73.74	192,490
1	12/3/2002	70.465	178,915
1	12/4/2002	76.84	197,882
1	12/5/2002	66.449	167,574
1	12/6/2002	72.172	176,674
1	12/7/2002	62.203	168,865
1	12/8/2002	65.528	190,748
1	12/9/2002	61.204	179,392
1	12/10/2002	73.699	186,035
1	12/11/2002	67.461	170,849
1	12/12/2002	75.376	194,554
1	12/13/2002	59.989	153,460
1	12/14/2002	68.99	177,279
1	12/15/2002	68.305	160,456
1	12/16/2002	76.191	180,966
1	12/17/2002	73.332	173,618
1	12/18/2002	76.888	195,180
1	12/19/2002	71.893	176,889
1	12/20/2002	67.569	170,932
1	12/21/2002	62.678	166,491
1	12/22/2002	70.113	179,450
1	12/23/2002	71.766	183,176
1	12/24/2002	70.094	183,058
1	12/25/2002	68.993	179,073
1	12/26/2002	72.084	190,734
1	12/27/2002	66.248	171,995

1	12/28/2002	71.41	188,655
1	12/29/2002	60.327	170,084
1	12/30/2002	60.528	169,080
1	12/31/2002	54.642	149,739
1	1/1/2003	73.915	190,490
1	1/2/2003	78.753	194,372
1	1/3/2003	64.163	174,996
1	1/4/2003	74.148	202,634
1	1/5/2003	66.118	176,220
1	1/6/2003	73.507	201,538
1	1/7/2003	61.691	170,119
1	1/8/2003	53.155	190,141
1	1/9/2003	51.59	150,755
1	1/10/2003	54.815	148,813
1	1/11/2003	67.307	178,120
1	1/12/2003	79.089	196,635
1	1/13/2003	60.962	167,295
1	1/14/2003	63.486	199,432
1	1/15/2003	57.585	174,044
1	1/16/2003	62.495	194,099
1	1/17/2003	31.403	95,315
1	1/18/2003	65.728	183,717
1	1/19/2003	60.339	163,905
1	1/20/2003	61.16	165,939
1	1/21/2003	55.715	164,810
1	1/22/2003	59.21	182,170
1	1/23/2003	55.487	186,596
1	1/24/2003	62.545	198,856
1	1/25/2003	62.512	178,918
1	1/26/2003	66.7	191,266
1	1/27/2003	61.967	169,600
1	1/28/2003	67.579	195,026
1	1/29/2003	61.284	173,870
1	1/30/2003	61.872	198,309
1	1/31/2003	58.385	171,516
1	2/1/2003	75.945	197,489
1	2/2/2003	66.362	168,728
1	2/3/2003	65.998	184,364
1	2/4/2003	68.644	176,414
1	2/5/2003	90.467	196,322
1	2/6/2003	58.866	171,981
1	2/7/2003	78.827	199,612
1	2/8/2003	63.091	174,303
1	2/9/2003	63.7	187,172
1	2/10/2003	48.019	168,271
1	2/11/2003	55.823	169,313
1	2/12/2003	62.516	159,288

1	2/13/2003	61.421	174,121
1	2/14/2003	62.005	158,766
1	2/15/2003	78.969	200,801
1	2/16/2003	72.08	184,036
1	2/17/2003	69.689	202,163
1	2/18/2003	62.206	163,617
1	2/19/2003	68.896	180,477
1	2/20/2003	64.623	173,881
1	2/21/2003	67.163	183,845
1	2/22/2003	57.606	157,110
1	2/23/2003	69.672	192,959
1	2/24/2003	57.34	194,459
1	2/25/2003	55.535	183,066
1	2/26/2003	62.888	185,446
1	2/27/2003	47.595	156,992
1	2/28/2003	51.073	147,424
1	3/1/2003	40.516	108,627
1	3/2/2003	52.253	144,424
1	3/3/2003	48.089	173,987
1	3/4/2003	49.411	152,776
1	3/5/2003	48.333	158,937
1	3/6/2003	58.036	202,330
1	3/7/2003	46.863	145,062
1	3/8/2003	49.793	175,267
1	3/9/2003	70.656	170,559
1	3/10/2003	62.434	202,802
1	3/11/2003	57.399	184,481
1	3/12/2003	45.609	164,665
1	3/13/2003	37.658	145,800
1	3/14/2003	58.95	199,236
1	3/15/2003	61.202	187,834
1	3/16/2003	53.613	170,221
1	3/17/2003	59.39	175,018
1	3/18/2003	78.889	209,616
1	3/19/2003	71.377	186,412
1	3/20/2003	86.469	198,170
1	3/21/2003	75.59	185,082
1	3/22/2003	91.133	212,229
1	3/23/2003	89.95	183,040
1	3/24/2003	68.44	199,438
1	3/25/2003	66.328	167,699
1	3/26/2003	87.734	208,448
1	3/27/2003	62.384	171,469
1	4/1/2003	77.815	192,159
1	4/2/2003	75.176	180,236
1	4/3/2003	66.211	194,903
1	4/4/2003	36.75	175,240

1	4/5/2003	62.096	198,466
1	4/6/2003	68.474	174,682
1	4/7/2003	71.167	204,526
1	4/8/2003	73.012	203,697
1	4/9/2003	76.151	202,733
1	4/10/2003	68.052	175,982
1	4/11/2003	75.146	191,851
1	4/12/2003	70.72	186,941
1	4/13/2003	58.355	150,660
1	4/14/2003	69.968	192,204
1	4/15/2003	57.581	162,914
1	4/16/2003	68.308	187,283
1	4/17/2003	69.638	194,059
1	4/18/2003	47.058	137,341
1	4/19/2003	40.801	138,266
1	4/20/2003	69.525	184,518
1	4/21/2003	63.383	195,627
1	4/22/2003	46.951	156,554
1	4/23/2003	53.949	166,751
1	4/24/2003	57.137	173,637
1	4/25/2003	67.083	198,800
1	4/26/2003	65.889	178,524
1	4/27/2003	63.961	184,933
1	4/28/2003	56.091	164,029
1	5/14/2003	0.049	15,011
1	5/15/2003	15.377	77,551
1	5/16/2003	68.357	191,499
1	5/17/2003	64.285	195,408
1	5/18/2003	18.734	103,256
1	5/19/2003	31.395	95,092
1	5/20/2003	22.936	92,627
1	5/21/2003	28.402	89,420
1	5/22/2003	41.112	124,468
1	5/23/2003	59.486	174,644
1	5/24/2003	54.912	160,872
1	5/25/2003	56.33	165,561
1	5/26/2003	58.981	169,606
1	5/27/2003	63.996	182,690
1	5/28/2003	63.645	171,811
1	5/29/2003	60.784	184,084
1	5/30/2003	54.991	184,091
1	5/31/2003	75.624	209,565
1	6/1/2003	60.852	182,601
1	6/2/2003	63.49	206,040
1	6/3/2003	60.287	183,880
1	6/4/2003	67.308	202,062
1	6/5/2003	60.479	181,552

1	6/6/2003	55.256	192,138
1	6/7/2003	60.258	186,045
1	6/8/2003	65.11	194,271
1	6/9/2003	57.75	176,036
1	6/10/2003	62.436	203,259
1	6/11/2003	66.898	189,842
1	6/12/2003	70.574	207,990
1	6/13/2003	56.696	175,684
1	6/14/2003	71.951	215,265
1	6/15/2003	58.017	186,958
1	6/16/2003	59.332	195,251
1	6/17/2003	50.246	162,323
1	6/18/2003	72.322	208,449
1	6/19/2003	64.908	188,054
1	6/20/2003	67.928	206,650
1	6/21/2003	62.11	190,843
1	6/22/2003	66.638	201,823
1	6/23/2003	64.963	195,499
1	6/24/2003	68.687	206,961
1	6/25/2003	60.499	189,095
1	6/26/2003	72.145	210,390
1	6/27/2003	64.627	187,355
1	6/28/2003	67.706	208,435
1	6/29/2003	67.217	187,558
1	6/30/2003	65.28	203,057
1	7/1/2003	65.351	190,432
1	7/2/2003	69.546	199,595
1	7/3/2003	64.51	190,141
1	7/4/2003	69.444	199,252
1	7/5/2003	63.391	186,550
1	7/6/2003	68.122	194,179
1	7/7/2003	64.627	194,081
1	7/8/2003	70.035	216,937
1	7/9/2003	67.854	192,724
1	7/10/2003	75.468	212,229
1	7/11/2003	40.227	119,467
1	7/12/2003	43.857	177,807
1	7/13/2003	64.739	190,585
1	7/14/2003	75.933	214,321
1	7/15/2003	65.332	189,958
1	7/16/2003	79.905	210,593
1	7/17/2003	66.713	185,541
1	7/18/2003	74.769	200,491
1	7/19/2003	63.41	179,781
1	7/20/2003	64.059	187,000
1	7/21/2003	64.143	182,203
1	7/22/2003	69.373	208,488

1	7/23/2003	61.926	187,284
1	7/24/2003	65.816	188,519
1	7/25/2003	68.838	192,488
1	7/26/2003	75.838	208,652
1	7/27/2003	81.805	189,342
1	7/28/2003	77.288	202,758
1	7/29/2003	64.397	181,305
1	7/30/2003	74.549	207,311
1	7/31/2003	60.462	178,377
1	8/1/2003	79.776	207,621
1	8/2/2003	74.712	190,328
1	8/3/2003	73.136	185,354
1	8/4/2003	69.243	182,655
1	8/5/2003	74.251	202,146
1	8/6/2003	68.204	180,048
1	8/7/2003	81.741	211,571
1	8/8/2003	75.561	180,633
1	8/9/2003	86.654	208,892
1	8/10/2003	72.31	183,393
1	8/11/2003	74.953	181,523
1	8/12/2003	69.09	171,808
1	8/13/2003	86.837	203,211
1	8/14/2003	73.976	186,090
1	8/15/2003	73.209	203,578
1	8/16/2003	67.895	181,561
1	8/17/2003	93.162	196,475
1	8/18/2003	72.154	174,771
1	8/19/2003	74.077	193,269
1	8/20/2003	73.109	175,428
1	8/21/2003	77.381	201,428
1	8/22/2003	70.2	182,433
1	8/23/2003	91.532	202,832
1	8/24/2003	65.128	177,111
1	8/25/2003	73.702	201,739
1	8/26/2003	84.332	190,904
1	8/27/2003	79.137	210,683
1	8/28/2003	78.61	181,626
1	8/29/2003	86.346	205,609
1	8/30/2003	68.113	169,092
1	8/31/2003	60.59	164,527
1	9/1/2003	80.553	183,088
1	9/2/2003	66.713	192,087
1	9/3/2003	84.924	200,176
1	9/4/2003	82.67	203,396
1	9/5/2003	64.663	170,245
1	9/6/2003	71.003	180,289
1	9/7/2003	68.442	188,070

1	9/8/2003	72.396	200,412
1	9/9/2003	52.094	186,675
1	9/10/2003	51.619	204,556
1	9/11/2003	60.897	188,556
1	9/12/2003	77.23	215,322
1	9/13/2003	70.109	191,303
1	9/14/2003	67.612	198,122
1	9/15/2003	50.225	144,245
1	9/16/2003	61.598	186,390
1	9/17/2003	47.096	176,742
1	9/18/2003	73.404	201,265
1	9/19/2003	78.07	183,382
1	9/20/2003	67.711	190,857
1	9/21/2003	50.187	147,848
1	9/22/2003	72.89	209,098
1	9/23/2003	63.921	188,354
1	9/24/2003	72.307	209,389
1	9/25/2003	68.655	189,550
1	9/26/2003	74.139	217,294
1	9/27/2003	62.645	192,418
1	9/28/2003	65.072	196,056
1	9/29/2003	51.733	150,167
1	9/30/2003	75.945	179,170
1	10/1/2003	75.132	191,347
1	10/2/2003	77.766	193,514
1	10/3/2003	70.78	180,580
1	10/4/2003	77.717	197,639
1	10/5/2003	63.532	169,279
1	10/6/2003	74.317	196,516
1	10/7/2003	69.527	176,009
1	10/8/2003	46.857	187,470
1	10/9/2003	59.214	164,025
1	10/10/2003	76.928	183,433
1	10/11/2003	61.462	167,840
1	10/12/2003	67.021	157,181
1	10/13/2003	58.332	149,366
1	10/14/2003	54.619	152,338
1	10/15/2003	67.231	162,497
1	10/16/2003	51.32	139,546
1	10/17/2003	25.108	97,924
1	10/18/2003	31.745	97,235
1	10/19/2003	28.424	115,530
1	10/20/2003	71.574	172,790
1	10/21/2003	58.697	161,902
1	10/22/2003	51.816	140,425
1	10/23/2003	45.927	130,821
1	10/24/2003	62.545	161,974

1	10/25/2003	39.379	114,413
1	10/26/2003	44.288	142,423
1	10/27/2003	70.436	193,057
1	10/28/2003	89.193	215,641
1	10/29/2003	73.661	193,136
1	10/30/2003	74.113	208,511
1	10/31/2003	79.092	190,986
1	11/1/2003	83.82	210,706
1	11/2/2003	76.881	193,170
1	11/3/2003	88.042	215,517
1	11/4/2003	73.123	188,981
1	11/5/2003	83.25	215,410
1	11/6/2003	68.31	193,683
1	11/7/2003	78.174	205,225
1	11/8/2003	68.221	184,594
1	11/9/2003	76.211	207,142
1	11/10/2003	74.678	182,625
1	11/11/2003	62.183	147,918
1	11/12/2003	40.936	112,803
1	11/13/2003	59.962	147,031
1	11/14/2003	69.853	179,370
1	11/15/2003	58.64	199,238
1	11/16/2003	65.906	217,826
1	11/17/2003	66.262	198,597
1	11/18/2003	67.264	209,841
1	11/19/2003	66.151	196,649
1	11/20/2003	1.077	3,432
1	11/23/2003	25.616	89,769
1	11/24/2003	83.178	210,402
1	11/25/2003	47.086	130,602
1	11/26/2003	71.232	211,313
1	11/27/2003	70.576	186,143
1	11/28/2003	81.882	205,139
1	11/29/2003	57.244	183,532
1	11/30/2003	59.679	201,943
1	12/1/2003	58.438	186,624
1	12/2/2003	70.331	210,820
1	12/3/2003	28.762	118,238
1	12/7/2003	6.674	27,268
1	12/8/2003	67.963	191,589
1	12/9/2003	58.688	192,922
1	12/10/2003	71.468	201,157
1	12/11/2003	68.585	188,687
1	12/12/2003	65.425	196,780
1	12/13/2003	67.233	188,328
1	12/14/2003	79.576	195,868
1	12/15/2003	58.623	162,122

1	12/16/2003	60.004	170,922
1	12/17/2003	75.008	205,815
1	12/18/2003	73.319	179,105
1	12/19/2003	78.713	207,009
1	12/20/2003	42.448	140,551
1	12/21/2003	42.35	150,557
1	12/22/2003	69.795	203,348
1	12/23/2003	47.569	192,196
1	12/24/2003	45.567	177,562
1	12/25/2003	53.871	201,360
1	12/26/2003	49.882	194,279
1	12/27/2003	42.371	205,291
1	12/28/2003	38.072	181,144
1	12/29/2003	44.555	203,197
1	12/30/2003	38.917	189,748
1	12/31/2003	40.608	202,584
	Max (tpd) -->	**93.162**	
	Max (lb/hr) -->	**7763.5**	

Note: Dates with no operation/emissions not shown

Unit ID	Date	SO2 (tons)	Heat Input (MMBtu)
2	1/10/2001	0.754	33,637
2	1/11/2001	48.572	155,023
2	1/12/2001	69.767	223,001
2	1/13/2001	63.279	199,585
2	1/14/2001	70.944	196,874
2	1/15/2001	70.445	196,066
2	1/16/2001	71.084	214,936
2	1/17/2001	73.798	206,033
2	1/18/2001	80.818	228,270
2	1/19/2001	65.111	199,193
2	1/20/2001	82.298	228,161
2	1/21/2001	67.036	191,946
2	1/22/2001	82.267	231,789
2	1/23/2001	69.272	202,867
2	1/24/2001	67.477	203,133
2	1/25/2001	65.347	208,993
2	1/26/2001	72.167	221,736
2	1/27/2001	62.866	198,308
2	1/28/2001	64.123	208,264
2	1/29/2001	57.277	185,626
2	1/30/2001	71.366	213,747
2	1/31/2001	64.4	192,322
2	2/1/2001	74.805	220,513
2	2/2/2001	65.668	199,773
2	2/3/2001	76.063	219,848
2	2/4/2001	66.935	184,402
2	2/5/2001	73.809	217,446
2	2/6/2001	60.475	165,070
2	2/7/2001	59.292	172,471
2	2/8/2001	58.984	185,584
2	2/9/2001	51.92	154,356
2	2/10/2001	77.024	216,492
2	2/11/2001	59.475	187,862
2	2/12/2001	67.554	213,302
2	2/13/2001	59.31	183,263
2	2/14/2001	73.915	216,849
2	2/15/2001	56.155	185,480
2	2/16/2001	60.275	200,034
2	2/17/2001	60.896	185,447
2	2/18/2001	68.563	210,910
2	2/19/2001	63.536	192,921
2	2/20/2001	67.91	198,402
2	2/21/2001	65.391	193,429
2	2/22/2001	75.288	224,203
2	2/23/2001	66.278	200,474

2	2/24/2001	58.537	179,453
2	2/25/2001	59.957	181,189
2	2/26/2001	67.115	195,041
2	2/27/2001	60.745	174,238
2	2/28/2001	65.639	197,401
2	3/1/2001	62.668	184,455
2	3/2/2001	68.041	191,218
2	3/3/2001	57.07	171,070
2	3/4/2001	54.392	173,991
2	3/5/2001	65.951	197,817
2	3/6/2001	58.349	193,610
2	3/7/2001	78.118	223,725
2	3/8/2001	66.484	208,325
2	3/9/2001	69.273	191,776
2	3/10/2001	71.556	207,104
2	3/11/2001	56.766	160,681
2	3/12/2001	65.797	189,519
2	3/13/2001	63.754	186,465
2	3/14/2001	66.415	190,865
2	3/15/2001	63.324	185,756
2	3/16/2001	63.264	199,374
2	3/17/2001	60.518	184,595
2	3/18/2001	60.969	197,853
2	3/19/2001	66.76	197,346
2	3/20/2001	72.834	214,610
2	3/21/2001	61.998	188,273
2	3/22/2001	67.614	199,344
2	3/23/2001	60.426	186,547
2	3/24/2001	64.326	199,333
2	3/25/2001	53.746	174,018
2	3/26/2001	64.952	205,578
2	3/27/2001	64.971	193,287
2	3/28/2001	62.664	200,393
2	3/29/2001	59.724	185,695
2	3/30/2001	58.081	178,069
2	3/31/2001	68.646	191,096
2	4/1/2001	65.108	187,792
2	4/2/2001	57.317	202,604
2	4/3/2001	61.401	187,272
2	4/4/2001	58.343	194,899
2	4/5/2001	62.93	184,590
2	4/6/2001	59.78	191,757
2	4/7/2001	56.841	184,682
2	4/8/2001	69.676	190,946
2	4/9/2001	70.81	185,970
2	4/10/2001	54.723	197,849
2	4/11/2001	54.058	166,491

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2	5/4/2001	70.899	214,110
2	5/5/2001	71.413	211,101
2	5/6/2001	63.354	193,817
2	5/7/2001	73.029	205,431
2	5/8/2001	68.396	200,902
2	5/9/2001	70.645	217,872
2	5/10/2001	67.923	208,187
2	5/11/2001	71.207	215,447
2	5/12/2001	62.622	180,366
2	5/13/2001	58.775	182,784
2	5/14/2001	68.965	197,405
2	5/15/2001	74.064	215,433
2	5/16/2001	66.586	197,138
2	5/17/2001	71.711	217,359
2	5/18/2001	70.055	206,643
2	5/19/2001	77.958	226,785
2	5/20/2001	68.772	204,157
2	5/21/2001	76.383	227,471
2	5/22/2001	58.712	177,827
2	5/23/2001	65.708	196,638
2	5/24/2001	63.432	189,095
2	5/25/2001	70.807	206,448
2	5/26/2001	65.271	193,677
2	5/27/2001	64.151	192,107
2	5/28/2001	52.023	150,016
2	5/29/2001	67.867	204,749
2	5/30/2001	67.63	199,560
2	5/31/2001	55.825	168,511
2	6/1/2001	62.407	184,927
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2	6/3/2001	67.295	208,569
2	6/4/2001	72.126	208,934
2	6/5/2001	73.841	217,607
2	6/6/2001	67.472	203,457
2	6/7/2001	69.52	206,278
2	6/8/2001	72.702	200,918
2	6/9/2001	71.159	210,583
2	6/10/2001	61.293	186,716
2	6/11/2001	65.811	203,227
2	6/12/2001	73.256	216,533
2	6/13/2001	76.688	225,531
2	6/14/2001	73.748	213,698
2	6/15/2001	73.415	210,730
2	6/16/2001	66.115	195,508
2	6/17/2001	69.267	201,585

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2	6/21/2001	74.099	214,438
2	6/22/2001	65.397	195,042
2	6/23/2001	71.333	204,508
2	6/24/2001	62.279	184,534
2	6/25/2001	69.734	206,170
2	6/26/2001	66.976	190,843
2	6/27/2001	66.883	201,570
2	6/28/2001	66.285	203,199
2	6/29/2001	72.059	202,362
2	6/30/2001	65.79	190,828
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2	7/2/2001	65.055	192,992
2	7/3/2001	77.963	205,510
2	7/4/2001	68.741	197,931
2	7/5/2001	68.553	197,585
2	7/6/2001	65.11	198,174
2	7/7/2001	74.56	213,383
2	7/8/2001	57.577	200,508
2	7/9/2001	62.687	223,282
2	7/10/2001	80.286	204,301
2	7/11/2001	80.159	221,400
2	7/12/2001	67.158	198,449
2	7/13/2001	80.201	221,335
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2	7/15/2001	68.191	179,878
2	7/16/2001	64.455	184,835
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2	7/19/2001	70.542	213,198
2	7/20/2001	78.579	212,660
2	7/21/2001	71.753	217,047
2	7/22/2001	67.675	202,953
2	7/23/2001	68.944	210,570
2	7/24/2001	55.819	209,676
2	7/25/2001	62.294	230,575
2	7/26/2001	65.226	205,030
2	7/27/2001	68.019	202,340
2	7/28/2001	26.181	74,905
2	7/31/2001	15.582	46,223
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2	8/5/2001	75.123	223,639

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2	8/8/2001	68.328	233,054
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2	8/11/2001	57.198	219,172
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2	8/13/2001	65.699	210,656
2	8/14/2001	61.753	203,483
2	8/15/2001	62.701	199,017
2	8/16/2001	68.982	213,177
2	8/17/2001	72.722	228,291
2	8/18/2001	66.308	208,089
2	8/19/2001	71.842	211,722
2	8/20/2001	66.222	203,776
2	8/21/2001	41.063	134,558
2	8/22/2001	73.13	219,632
2	8/23/2001	75.166	230,730
2	8/24/2001	69.238	218,750
2	8/25/2001	60.076	199,470
2	8/26/2001	65.824	205,122
2	8/27/2001	67.93	205,057
2	8/28/2001	66.653	207,979
2	8/29/2001	69.296	207,352
2	8/30/2001	71.494	227,618
2	8/31/2001	66.864	214,649
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2	9/3/2001	58.511	203,589
2	9/4/2001	53.648	217,219
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2	9/6/2001	68.612	213,826
2	9/7/2001	76.503	226,878
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2	9/9/2001	66.574	193,595
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2	9/11/2001	72.633	230,033
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2	9/13/2001	73.934	227,204
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2	9/15/2001	59.653	186,297
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2	9/18/2001	68.244	205,911
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2	9/21/2001	56.879	205,070

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2	9/26/2001	63.043	186,581
2	9/27/2001	66.482	200,156
2	9/28/2001	63.309	196,213
2	9/29/2001	62.67	194,975
2	9/30/2001	52.489	167,163
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2	10/3/2001	62.915	218,269
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2	10/7/2001	62.748	204,980
2	10/8/2001	67.948	216,413
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2	10/10/2001	73.355	229,679
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2	10/16/2001	70.195	216,177
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2	10/18/2001	63.541	201,395
2	10/19/2001	57.453	184,769
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2	10/22/2001	66.245	208,530
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2	11/18/2001	35.186	123,443
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2	11/21/2001	55.149	181,063
2	11/22/2001	36.993	125,983
2	11/23/2001	38.869	125,294
2	11/24/2001	45.988	144,401
2	11/25/2001	43.804	151,134
2	11/26/2001	54.635	176,780
2	11/27/2001	62.528	200,430
2	11/28/2001	70.364	229,371

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2	11/30/2001	57.485	170,671
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2	12/2/2001	42.317	133,471
2	12/3/2001	59.164	200,205
2	12/4/2001	64.828	204,270
2	12/5/2001	68.503	212,388
2	12/6/2001	62.011	193,322
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2	12/8/2001	55.142	197,931
2	12/9/2001	57.054	188,726
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2	12/11/2001	74.844	226,565
2	12/12/2001	66.64	207,128
2	12/13/2001	67.535	207,164
2	12/14/2001	66.079	209,182
2	12/15/2001	66.339	235,036
2	12/16/2001	58.733	194,882
2	12/17/2001	64.843	211,213
2	12/18/2001	61.79	194,774
2	12/19/2001	64.132	202,373
2	12/20/2001	61.942	193,031
2	12/21/2001	68.826	222,563
2	12/22/2001	58.313	189,778
2	12/23/2001	53.796	190,558
2	12/24/2001	58.919	192,729
2	12/25/2001	52.663	176,095
2	12/26/2001	61.802	201,052
2	12/27/2001	71.321	223,889
2	12/28/2001	61.129	193,331
2	12/29/2001	69.055	224,118
2	12/30/2001	65.647	219,707
2	12/31/2001	52.399	227,640
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2	1/3/2002	75.864	245,312
2	1/4/2002	70.449	221,367
2	1/5/2002	73.951	237,679
2	1/6/2002	63.773	208,778
2	1/7/2002	67.44	226,227
2	1/8/2002	46.998	159,482
2	1/9/2002	62.622	212,629
2	1/10/2002	61.763	204,240
2	1/11/2002	62.735	204,685
2	1/12/2002	58.128	189,070
2	1/13/2002	63.343	205,872
2	1/14/2002	39.41	120,321

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2	1/21/2002	72.29	230,019
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2	1/23/2002	61.568	197,176
2	1/24/2002	55.53	184,772
2	1/25/2002	58.035	191,601
2	1/26/2002	51.602	174,901
2	1/27/2002	52.553	178,355
2	1/28/2002	50.679	152,352
2	1/29/2002	60.533	187,478
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2	2/4/2002	66.661	210,080
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2	2/6/2002	70.912	222,089
2	2/7/2002	61.621	194,478
2	2/8/2002	62.479	199,087
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2	2/12/2002	61.278	200,113
2	2/13/2002	62.493	200,276
2	2/14/2002	53.959	211,516
2	2/15/2002	51.148	204,465
2	2/16/2002	68.171	218,723
2	2/17/2002	50.575	171,532
2	2/18/2002	59.098	204,245
2	2/19/2002	50.629	166,054
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2	2/23/2002	18.532	70,454
2	2/24/2002	52.372	189,719
2	2/25/2002	65.295	201,438
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2	3/8/2002	67.506	216,459

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2	3/13/2002	56.569	190,646
2	3/14/2002	56.669	230,970
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2	4/4/2002	71.24	213,172
2	4/5/2002	64.366	196,330
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2	4/8/2002	67.72	207,416
2	4/9/2002	64.94	196,108
2	4/10/2002	66.561	211,263
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2	4/12/2002	66.671	201,828
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2	4/15/2002	69.001	209,466
2	4/16/2002	60.639	205,080
2	4/17/2002	61.127	199,518
2	4/18/2002	54.461	206,262
2	4/19/2002	62.814	211,213
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2	4/23/2002	68.627	202,654
2	4/24/2002	69.78	213,992
2	4/25/2002	63.821	199,226
2	4/26/2002	66.662	207,529
2	4/27/2002	67.558	197,847
2	4/28/2002	78.7	217,106
2	4/29/2002	69.386	198,134
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2	7/20/2002	38.357	117,244
2	7/21/2002	38.988	118,885
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2	7/23/2002	42.915	131,892
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2	7/30/2002	42.387	132,270
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2	8/3/2002	42.239	132,488
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2	8/8/2002	43.569	128,427
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2	8/13/2002	45.872	130,659
2	8/14/2002	41.298	122,162
2	8/15/2002	42.519	129,385
2	8/16/2002	40.682	131,262
2	8/17/2002	42.923	125,941
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2	8/19/2002	36.749	117,565
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2	9/8/2002	43.014	125,865
2	9/9/2002	42.505	134,267
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2	9/11/2002	46.077	134,731
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2	9/21/2002	42.757	132,226
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2	9/25/2002	43.73	129,196
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2	10/5/2002	46.533	132,296
2	10/6/2002	37.951	129,378
2	10/7/2002	37.966	134,015
2	10/8/2002	52.868	131,411
2	10/9/2002	48.696	130,423
2	10/10/2002	42.076	126,447
2	10/11/2002	43.721	132,825
2	10/12/2002	40.764	133,441
2	10/13/2002	41.794	131,590
2	10/14/2002	43.046	124,950
2	10/15/2002	42.015	131,725
2	10/16/2002	41.245	130,847
2	10/17/2002	42.07	125,099
2	10/18/2002	42.819	125,107
2	10/19/2002	45.384	132,512

2	10/20/2002	41.747	122,107
2	10/21/2002	46.708	127,818
2	10/22/2002	39.902	124,298
2	10/23/2002	46.263	131,562
2	10/24/2002	47.766	131,047
2	10/25/2002	41.849	124,779
2	10/26/2002	41.564	123,656
2	10/27/2002	43.533	129,717
2	10/28/2002	43.741	130,411
2	10/29/2002	51.355	131,682
2	10/30/2002	45.219	125,490
2	10/31/2002	44.394	127,462
2	11/1/2002	44.205	129,628
2	11/2/2002	44.643	129,261
2	11/3/2002	40.96	123,745
2	11/4/2002	44.925	129,527
2	11/5/2002	44.343	129,860
2	11/6/2002	39.085	128,247
2	11/7/2002	39.211	116,214
2	11/8/2002	0.112	713
2	11/9/2002	30.216	89,527
2	11/10/2002	42.778	132,346
2	11/11/2002	45.237	135,241
2	11/12/2002	42.721	133,800
2	11/13/2002	40.472	126,955
2	11/14/2002	43.795	134,896
2	11/15/2002	43.198	131,216
2	11/16/2002	45.042	131,855
2	11/17/2002	38.768	124,964
2	11/18/2002	45.241	134,505
2	11/19/2002	43.17	128,974
2	11/20/2002	44.857	133,926
2	11/21/2002	34.507	124,369
2	11/22/2002	40.563	134,614
2	11/23/2002	41.97	126,004
2	11/24/2002	42.291	130,382
2	11/25/2002	41.495	124,334
2	11/26/2002	37.269	124,510
2	11/27/2002	49.643	130,574
2	11/28/2002	39.346	117,870
2	11/29/2002	36.85	112,104
2	11/30/2002	38.929	116,062
2	12/1/2002	43.494	125,327
2	12/2/2002	43.673	128,968
2	12/3/2002	44.758	128,720
2	12/4/2002	40.619	120,228
2	12/5/2002	44.174	123,841

2	12/6/2002	45.294	122,380
2	12/7/2002	44.022	130,355
2	12/8/2002	39.016	125,323
2	12/9/2002	39.942	128,946
2	12/10/2002	45.545	129,204
2	12/11/2002	46.137	129,573
2	12/12/2002	42.167	122,406
2	12/13/2002	43.991	125,979
2	12/14/2002	42.538	122,758
2	12/15/2002	44.708	118,376
2	12/16/2002	44.316	119,716
2	12/17/2002	50.162	133,839
2	12/18/2002	46.255	134,021
2	12/19/2002	45.517	126,790
2	12/20/2002	40.965	115,263
2	12/21/2002	41.574	121,203
2	12/22/2002	39.851	114,174
2	12/23/2002	46.372	130,222
2	12/24/2002	42.257	121,970
2	12/25/2002	43.695	124,949
2	12/26/2002	45.922	131,297
2	12/27/2002	42.103	126,936
2	12/28/2002	41.979	125,825
2	12/29/2002	41.407	130,355
2	12/30/2002	39.035	125,098
2	12/31/2002	33.961	106,812
2	1/1/2003	0.341	1,291
2	1/2/2003	24.871	75,015
2	1/3/2003	43.488	131,086
2	1/4/2003	44.772	133,140
2	1/5/2003	43.777	127,572
2	1/6/2003	41.851	127,057
2	1/7/2003	43.265	129,584
2	1/8/2003	33.494	135,839
2	1/9/2003	34.51	117,031
2	1/10/2003	32.859	105,555
2	1/11/2003	45.679	133,252
2	1/12/2003	47.269	131,567
2	1/13/2003	43.467	131,756
2	1/14/2003	34.278	121,976
2	1/15/2003	37.056	126,788
2	1/16/2003	35.639	124,641
2	1/17/2003	40.614	126,291
2	1/18/2003	27.459	85,135
2	1/19/2003	17.771	59,166
2	1/20/2003	35.263	109,848
2	1/21/2003	35.953	123,177

2	1/22/2003	37.714	131,248
2	1/23/2003	35.122	129,180
2	1/24/2003	36.233	127,447
2	1/25/2003	39.378	127,484
2	1/26/2003	40.25	132,336
2	1/27/2003	40.483	128,508
2	1/28/2003	37.561	124,953
2	1/29/2003	38.808	128,100
2	1/30/2003	35.494	130,346
2	1/31/2003	38.757	133,533
2	2/1/2003	41.725	127,852
2	2/2/2003	40.329	120,575
2	2/3/2003	42.013	132,787
2	2/4/2003	43.945	124,794
2	2/5/2003	51.338	123,725
2	2/6/2003	41.152	131,622
2	2/7/2003	45.95	131,172
2	2/8/2003	43.205	130,678
2	2/9/2003	36.771	121,808
2	2/10/2003	33.438	126,701
2	2/11/2003	35.582	123,701
2	2/12/2003	47.622	134,658
2	2/13/2003	38.8	124,207
2	2/14/2003	44.771	131,396
2	2/15/2003	46.803	134,435
2	2/16/2003	45.905	132,770
2	2/17/2003	41.288	133,121
2	2/18/2003	45.265	131,622
2	2/19/2003	42.955	126,106
2	2/20/2003	43.088	128,814
2	2/21/2003	38.065	117,061
2	2/22/2003	24.402	77,292
2	2/23/2003	29.682	90,028
2	2/24/2003	40.007	131,088
2	2/25/2003	38.767	126,340
2	2/26/2003	36.996	121,711
2	2/27/2003	35.323	129,456
2	2/28/2003	38.09	123,264
2	3/1/2003	40.001	116,912
2	3/2/2003	40.728	125,999
2	3/3/2003	33.138	132,172
2	3/4/2003	20.669	79,737
2	3/5/2003	36.366	137,002
2	3/6/2003	34.559	126,821
2	3/7/2003	33.253	114,835
2	4/22/2003	0.024	2,455
2	4/23/2003	0.57	6,409

2	4/24/2003	0.346	4,998
2	4/25/2003	1.653	19,701
2	4/26/2003	1.182	11,608
2	4/27/2003	1.331	10,900
2	4/28/2003	27.687	97,392
2	4/29/2003	23.224	72,650
2	5/4/2003	0.227	2,424
2	5/5/2003	17.06	57,849
2	5/6/2003	30.047	78,658
2	5/7/2003	46.492	142,062
2	5/8/2003	72.41	213,935
2	5/9/2003	68.937	207,975
2	5/10/2003	74.992	230,885
2	5/11/2003	67.38	200,812
2	5/12/2003	70.581	210,656
2	5/13/2003	57.171	171,045
2	5/14/2003	70.563	200,534
2	5/15/2003	70.167	202,730
2	5/16/2003	72.346	205,881
2	5/17/2003	58.061	185,961
2	5/18/2003	19.448	115,299
2	5/19/2003	31.077	101,821
2	5/20/2003	22.744	99,360
2	5/21/2003	25.872	89,078
2	5/22/2003	36.635	120,936
2	5/23/2003	48.567	147,872
2	5/24/2003	52.07	156,613
2	5/25/2003	46.489	143,001
2	5/26/2003	58.979	174,641
2	5/27/2003	55.063	161,496
2	5/28/2003	65.86	179,119
2	5/29/2003	55.553	174,322
2	5/30/2003	60.648	208,039
2	5/31/2003	71.727	198,338
2	6/1/2003	70.761	212,833
2	6/2/2003	61.365	203,050
2	6/3/2003	68.958	210,743
2	6/4/2003	62.461	182,842
2	6/5/2003	62.573	183,088
2	6/6/2003	34.208	115,096
2	6/7/2003	65.11	197,511
2	6/8/2003	62.324	181,844
2	6/9/2003	63.884	191,746
2	6/10/2003	63.19	201,659
2	6/11/2003	72.437	206,864
2	6/12/2003	58.341	175,572
2	6/13/2003	56.284	179,098

2	6/14/2003	61.374	193,446
2	6/15/2003	57.086	189,912
2	6/16/2003	55.164	189,091
2	6/17/2003	62.629	196,250
2	6/18/2003	64.786	189,691
2	6/19/2003	73.637	211,207
2	6/20/2003	63.431	197,470
2	6/21/2003	63.918	197,410
2	6/22/2003	64.29	198,094
2	6/23/2003	75.428	227,341
2	6/24/2003	66.436	202,040
2	6/25/2003	72.313	226,759
2	6/26/2003	66.525	197,524
2	6/27/2003	68.121	197,548
2	6/28/2003	63.802	200,025
2	6/29/2003	77.756	220,554
2	6/30/2003	52.714	170,043
2	7/1/2003	71.656	214,756
2	7/2/2003	63.08	186,501
2	7/3/2003	73.932	215,785
2	7/4/2003	60.631	178,823
2	7/5/2003	68.874	205,836
2	7/6/2003	61.564	178,612
2	7/7/2003	74.013	223,042
2	7/8/2003	67.694	208,792
2	7/9/2003	76.708	221,622
2	7/10/2003	68.181	197,469
2	7/11/2003	66.898	195,582
2	7/12/2003	59.027	207,695
2	7/13/2003	75.38	218,117
2	7/14/2003	69.033	203,421
2	7/15/2003	78.388	230,380
2	7/16/2003	74.257	203,521
2	7/17/2003	75.934	217,919
2	7/18/2003	68.109	191,966
2	7/19/2003	72.846	207,656
2	7/20/2003	61.14	178,396
2	7/21/2003	78.679	230,258
2	7/22/2003	62.621	195,532
2	7/23/2003	65.829	203,912
2	7/24/2003	60.599	178,711
2	7/25/2003	73.576	210,531
2	7/26/2003	70.157	197,491
2	7/27/2003	90.528	215,849
2	7/28/2003	68.841	191,139
2	7/29/2003	70.723	204,797
2	7/30/2003	67.712	197,828

2	7/31/2003	66.125	202,486
2	8/1/2003	71.541	196,492
2	8/2/2003	80.742	214,317
2	8/3/2003	61.329	168,613
2	8/4/2003	68.92	195,435
2	8/5/2003	61.499	178,308
2	8/6/2003	73.18	207,756
2	8/7/2003	69.856	190,980
2	8/8/2003	77.228	187,873
2	8/9/2003	72.809	191,248
2	8/10/2003	75.267	200,240
2	8/11/2003	60.618	154,754
2	8/12/2003	63.981	167,678
2	8/13/2003	74.526	186,716
2	8/14/2003	82.677	219,956
2	8/15/2003	69.953	198,724
2	8/16/2003	78.945	219,751
2	8/17/2003	84.556	185,941
2	8/18/2003	87.543	217,540
2	8/19/2003	74.519	199,463
2	8/20/2003	88.865	221,338
2	8/21/2003	70.209	187,889
2	8/22/2003	81.354	217,865
2	8/23/2003	77.177	179,597
2	8/24/2003	62.13	172,445
2	8/25/2003	68.592	194,288
2	8/26/2003	87.919	203,448
2	8/27/2003	80.932	216,513
2	8/28/2003	82.687	197,918
2	8/29/2003	82.208	202,540
2	8/30/2003	83.364	211,336
2	8/31/2003	65.314	183,922
2	9/1/2003	93.901	216,245
2	9/2/2003	67.103	195,437
2	9/3/2003	87.882	211,604
2	9/4/2003	73.831	185,708
2	9/5/2003	62.172	169,129
2	9/6/2003	69.933	172,549
2	9/7/2003	71.082	186,768
2	9/8/2003	67.777	194,007
2	9/9/2003	59.869	208,235
2	9/10/2003	47.297	191,134
2	9/11/2003	70.439	214,754
2	9/12/2003	68.502	194,246
2	9/13/2003	77.372	212,995
2	9/14/2003	62.285	185,112
2	9/15/2003	62.138	181,443

2	9/16/2003	54.365	159,836
2	9/17/2003	44.087	170,662
2	9/18/2003	64.266	179,510
2	9/19/2003	84.561	198,395
2	9/20/2003	61.237	175,201
2	9/21/2003	45.248	135,969
2	9/22/2003	64.048	184,563
2	9/23/2003	72.375	210,158
2	9/24/2003	67.512	190,162
2	9/25/2003	82.877	216,409
2	9/26/2003	66.416	195,764
2	9/27/2003	71.255	214,105
2	9/28/2003	48.564	144,440
2	10/1/2003	0.739	5,350
2	10/2/2003	33.504	91,269
2	10/3/2003	69.337	173,240
2	10/4/2003	70.961	181,775
2	10/5/2003	78.203	208,329
2	10/6/2003	75.187	201,250
2	10/7/2003	89.169	220,542
2	10/8/2003	49.203	193,751
2	10/9/2003	67.662	186,810
2	10/10/2003	79.918	191,964
2	10/11/2003	77.311	208,470
2	10/12/2003	55.02	133,243
2	10/13/2003	57.783	146,579
2	10/14/2003	57.2	158,381
2	10/15/2003	70.099	163,846
2	10/16/2003	39.172	119,677
2	10/17/2003	22.491	110,018
2	10/18/2003	28.818	111,833
2	10/19/2003	26.99	97,703
2	10/20/2003	47.314	136,379
2	10/21/2003	58.792	171,856
2	10/22/2003	44.082	123,176
2	10/23/2003	38.065	108,419
2	10/24/2003	46.912	121,940
2	10/25/2003	40.834	121,636
2	10/26/2003	41.361	134,381
2	10/27/2003	77.893	217,120
2	10/28/2003	81.213	189,818
2	10/29/2003	88.045	219,499
2	10/30/2003	69.841	189,813
2	10/31/2003	88.683	217,110
2	11/1/2003	73.396	187,086
2	11/2/2003	83.102	204,959
2	11/3/2003	78.948	190,234

2	11/4/2003	82.853	207,766
2	11/5/2003	80.004	205,747
2	11/6/2003	72.8	209,571
2	11/7/2003	68.317	179,234
2	11/8/2003	78.886	216,308
2	11/9/2003	66.667	184,689
2	11/10/2003	78.976	195,905
2	11/11/2003	52.075	130,022
2	11/12/2003	41.692	117,091
2	11/13/2003	11.611	36,258
2	11/17/2003	0.17	2,225
2	11/18/2003	38.966	117,867
2	11/19/2003	65.18	198,434
2	11/20/2003	71.803	194,782
2	11/21/2003	83.116	211,544
2	11/22/2003	70.553	193,300
2	11/23/2003	74.376	201,621
2	11/24/2003	77.352	199,592
2	11/25/2003	80.788	215,593
2	11/26/2003	63.023	192,250
2	11/27/2003	63.937	183,110
2	11/28/2003	68.873	184,297
2	11/29/2003	66.042	216,610
2	11/30/2003	46.244	167,797
2	12/1/2003	57.318	183,858
2	12/2/2003	63.35	181,812
2	12/3/2003	56.658	195,654
2	12/4/2003	65.813	180,092
2	12/5/2003	58.821	198,595
2	12/6/2003	54.429	201,880
2	12/7/2003	87.118	207,001
2	12/8/2003	61.162	166,563
2	12/9/2003	65.51	208,456
2	12/10/2003	73.371	197,599
2	12/11/2003	81.449	210,498
2	12/12/2003	60.767	176,633
2	12/13/2003	75.382	202,675
2	12/14/2003	68.046	166,486
2	12/15/2003	76.107	200,848
2	12/16/2003	59.007	163,400
2	12/17/2003	74.676	202,708
2	12/18/2003	80.577	193,320
2	12/19/2003	71.731	183,867
2	12/20/2003	71.602	216,101
2	12/21/2003	57.933	178,546
2	12/22/2003	56.158	161,064
2	12/23/2003	47.942	181,785

2	12/24/2003	56.125	196,775
2	12/25/2003	51.062	177,009
2	12/26/2003	54.125	196,221
2	12/27/2003	40.469	186,754
2	12/28/2003	41.98	191,214
2	12/29/2003	40.674	182,939
2	12/30/2003	44.935	209,032
2	12/31/2003	42.973	185,415
	Max (tpd) -->	**93.901**	
	Max (lb/hr) -->	**7825.1**	

Note: Dates with no operation/emissions not shown

Unit ID	Date	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)
1	1/1/2009	0.2417	22.557	185,974
1	1/2/2009	0.229	21.102	183,955
1	1/3/2009	0.2418	21.9	178,066
1	1/4/2009	0.3366	29.789	180,075
1	1/5/2009	0.3364	31.511	187,206
1	1/6/2009	0.3416	32.861	192,024
1	1/7/2009	0.3303	31.933	193,023
1	1/8/2009	0.3044	29.676	194,965
1	1/9/2009	0.2255	20.636	182,247
1	1/10/2009	0.2662	18.387	144,944
1	1/11/2009	0.2362	20.178	172,039
1	1/12/2009	0.2348	22.039	186,247
1	1/13/2009	0.2088	16.731	158,242
1	1/14/2009	0.172	11.413	132,759
1	1/15/2009	0.1951	12.023	120,430
1	1/16/2009	0.2145	13.936	129,923
1	1/17/2009	0.1877	1.053	8,769
1	1/19/2009	0.0508	0.224	6,180
1	1/20/2009	0.2751	22.771	172,042
1	1/21/2009	0.2678	27.201	203,889
1	1/22/2009	0.2832	28.739	202,984
1	1/23/2009	0.2964	29.004	195,578
1	1/24/2009	0.2543	22.006	181,460
1	1/25/2009	0.2193	21.944	199,901
1	1/26/2009	0.2823	27.765	196,432
1	1/27/2009	0.2893	23.969	166,298
1	1/28/2009	0.2787	21.49	156,515
1	1/29/2009	0.2604	22.952	175,543
1	1/30/2009	0.2155	16.605	153,462
1	1/31/2009	0.2364	14.627	124,976
1	2/1/2009	0.252	20.969	166,864
1	2/2/2009	0.2503	19.149	155,816
1	2/3/2009	0.2304	21.501	187,220
1	2/4/2009	0.2326	21.196	182,571
1	2/5/2009	0.2295	18.233	156,315
1	2/6/2009	0.2191	21.27	194,417
1	2/7/2009	0.2425	22.265	187,834
1	2/8/2009	0.2223	22.37	201,308
1	2/9/2009	0.2375	23.27	195,674
1	2/10/2009	0.2649	24.645	185,718
1	2/11/2009	0.2936	26.569	180,885
1	2/12/2009	0.2832	27.88	197,109
1	2/13/2009	0.2948	29.084	197,610
1	2/14/2009	0.2948	23.967	165,802
1	2/15/2009	0.2688	25.925	193,017

1	2/16/2009	0.2419	22.894	189,774
1	2/17/2009	0.2365	22.752	193,112
1	2/18/2009	0.2326	20.909	179,771
1	2/19/2009	0.2327	16.466	129,297
1	2/20/2009	0.2777	24.159	173,092
1	2/21/2009	0.3317	28.161	172,865
1	2/22/2009	0.2971	26.247	177,509
1	2/23/2009	0.2568	24.565	191,481
1	2/24/2009	0.2597	24.822	190,964
1	2/25/2009	0.2659	23.68	178,208
1	2/26/2009	0.2962	26.941	181,698
1	2/27/2009	0.2946	25.36	175,220
1	2/28/2009	0.2531	21.377	170,065
1	3/1/2009	0.2629	25.952	197,521
1	3/2/2009	0.2688	26.674	198,445
1	3/3/2009	0.2677	26.519	198,236
1	3/4/2009	0.2792	26.801	190,996
1	3/5/2009	0.2172	20.312	186,838
1	3/6/2009	0.2316	23.537	202,821
1	3/7/2009	0.2378	18.594	157,394
1	3/8/2009	0.2346	21.958	187,077
1	3/9/2009	0.2279	20.968	181,867
1	3/10/2009	0.2394	23.077	190,866
1	3/11/2009	0.2459	24.583	200,550
1	3/12/2009	0.2488	22.693	182,849
1	3/13/2009	0.226	22.412	198,704
1	3/14/2009	0.2755	25.641	188,369
1	3/15/2009	0.242	23.083	191,574
1	3/16/2009	0.2407	23.256	193,804
1	3/17/2009	0.2453	23.086	189,229
1	3/18/2009	0.2315	23.342	201,601
1	3/19/2009	0.2322	22.393	192,481
1	3/20/2009	0.2223	21.275	190,261
1	3/21/2009	0.2848	25.606	182,647
1	3/22/2009	0.2231	20.163	180,672
1	3/23/2009	0.2219	20.184	182,865
1	3/24/2009	0.227	20.394	179,816
1	3/25/2009	0.2252	17.466	155,017
1	3/26/2009	0.3166	22.005	139,523
1	3/27/2009	0.2665	20.626	159,139
1	3/28/2009	0.2748	22.249	163,292
1	3/29/2009	0.2876	24.313	169,540
1	3/30/2009	0.2566	18.694	147,977
1	3/31/2009	0.2418	20.157	170,786
1	4/1/2009	0.2425	20.385	169,170
1	4/2/2009	0.2625	23.178	175,663
1	4/3/2009	0.2749	7.911	59,243

1	5/28/2009	0.0287	0.083	6,885
1	5/29/2009	0.0786	1.378	19,230
1	5/30/2009	0.2526	10.539	85,244
1	5/31/2009	0.0899	1.982	20,766
1	6/1/2009	0.26	15.038	122,900
1	6/3/2009	0.1327	7.661	62,957
1	6/4/2009	0.2477	16.053	138,038
1	6/5/2009	0.199	14.148	144,774
1	6/6/2009	0.2236	16.432	157,342
1	6/7/2009	0.2445	21.247	168,616
1	6/8/2009	0.2495	21.429	171,595
1	6/9/2009	0.2165	18.829	176,195
1	6/10/2009	0.2166	19.84	182,888
1	6/11/2009	0.2525	19.041	152,239
1	6/12/2009	0.2261	15.507	129,907
1	6/13/2009	0.229	16.4	148,419
1	6/14/2009	0.2191	15.878	147,645
1	6/15/2009	0.2167	19.406	175,677
1	6/16/2009	0.2202	18.626	167,794
1	6/17/2009	0.2194	20.474	186,024
1	6/18/2009	0.224	19.253	172,835
1	6/19/2009	0.227	20.813	184,848
1	6/20/2009	0.2731	24.007	177,114
1	6/21/2009	0.2538	24.095	191,110
1	6/22/2009	0.2253	21.912	194,107
1	6/23/2009	0.2313	22.821	197,316
1	6/24/2009	0.2539	24.536	192,962
1	6/25/2009	0.27	25.93	192,250
1	6/26/2009	0.2407	22.151	183,922
1	6/27/2009	0.2341	23.052	196,801
1	6/28/2009	0.2227	18.801	169,557
1	6/29/2009	0.214	16.968	157,727
1	6/30/2009	0.2357	16.931	140,820
1	7/1/2009	0.2701	21.895	161,488
1	7/2/2009	0.2266	19.26	169,047
1	7/3/2009	0.2322	21.273	183,230
1	7/4/2009	0.2604	19.154	152,742
1	7/5/2009	0.2276	17.629	153,938
1	7/6/2009	0.2195	18.51	168,092
1	7/7/2009	0.2192	20.064	182,222
1	7/8/2009	0.2178	19.794	180,994
1	7/9/2009	0.2311	21.53	185,874
1	7/10/2009	0.2643	23.126	180,863
1	7/11/2009	0.231	21.777	187,959
1	7/12/2009	0.2395	22.676	188,909
1	7/13/2009	0.2328	22.305	191,569
1	7/14/2009	0.2259	19.839	174,964

1	7/15/2009	0.2104	18.974	178,437
1	7/16/2009	0.279	24.991	178,594
1	7/17/2009	0.268	22.174	163,644
1	7/18/2009	0.3062	21.149	139,841
1	7/19/2009	0.2583	15.447	131,234
1	7/20/2009	0.2221	17.685	157,902
1	7/21/2009	0.2088	17.162	162,416
1	7/22/2009	0.2248	18.977	168,446
1	7/23/2009	0.2218	21.006	189,176
1	7/24/2009	0.2592	22.812	174,486
1	7/25/2009	0.2445	19.792	172,882
1	7/26/2009	0.2194	19.74	178,570
1	7/27/2009	0.2739	25.05	184,085
1	7/28/2009	0.2653	23.752	178,477
1	7/29/2009	0.259	22.421	173,100
1	7/30/2009	0.2096	14.423	137,320
1	8/1/2009	0.1339	5.494	51,274
1	8/2/2009	0.2293	20.221	176,461
1	8/3/2009	0.218	21.863	200,576
1	8/4/2009	0.2283	22.657	198,572
1	8/5/2009	0.2138	20.259	189,372
1	8/6/2009	0.217	19.174	176,305
1	8/7/2009	0.2181	20.147	184,761
1	8/8/2009	0.2771	24.472	177,359
1	8/9/2009	0.2812	27.31	193,766
1	8/10/2009	0.2857	28.233	197,731
1	8/11/2009	0.2744	26.897	196,156
1	8/12/2009	0.2698	24.817	182,817
1	8/13/2009	0.269	24.551	181,456
1	8/14/2009	0.2743	26.741	195,153
1	8/15/2009	0.2836	24.237	174,577
1	8/16/2009	0.2333	22.542	193,038
1	8/17/2009	0.272	26.42	194,019
1	8/18/2009	0.2321	21.397	184,088
1	8/19/2009	0.2271	20.926	183,818
1	8/20/2009	0.236	20.698	175,508
1	8/21/2009	0.2556	21.222	164,035
1	8/22/2009	0.2527	20.179	166,278
1	8/23/2009	0.288	22.807	161,085
1	8/24/2009	0.2919	24.46	167,101
1	8/25/2009	0.2717	23.916	175,933
1	8/26/2009	0.2889	25.766	177,843
1	8/27/2009	0.2782	25.141	180,206
1	8/28/2009	0.2753	26.642	193,609
1	8/29/2009	0.2828	23.682	169,967
1	8/30/2009	0.2709	22.767	171,656
1	8/31/2009	0.2385	20.603	172,786

1	9/1/2009	0.2895	23.532	165,149
1	9/2/2009	0.2393	20.326	171,089
1	9/3/2009	0.2754	25.441	182,556
1	9/4/2009	0.2936	28.943	197,227
1	9/5/2009	0.2339	19.971	172,357
1	9/6/2009	0.2321	20.473	176,563
1	9/7/2009	0.2785	23.08	166,814
1	9/8/2009	0.2849	26.244	182,516
1	9/9/2009	0.2972	29.066	195,567
1	9/10/2009	0.3008	29.164	193,968
1	9/11/2009	0.2925	27.837	190,060
1	9/12/2009	0.309	25.17	164,710
1	9/13/2009	0.2767	22.257	159,705
1	9/14/2009	0.2844	26.049	182,422
1	9/15/2009	0.2845	27.594	193,972
1	9/16/2009	0.2789	26.122	187,725
1	9/17/2009	0.2723	26.244	192,695
1	9/18/2009	0.2669	25.69	192,762
1	9/19/2009	0.2603	21.785	172,989
1	9/20/2009	0.2673	24.945	185,873
1	9/21/2009	0.2783	27.284	196,072
1	9/22/2009	0.2793	24.525	174,692
1	9/23/2009	0.2764	25.169	181,883
1	9/24/2009	0.2818	23.014	163,024
1	9/25/2009	0.254	22.424	176,232
1	9/26/2009	0.3217	25.439	164,445
1	9/27/2009	0.2624	22.396	171,350
1	9/28/2009	0.244	21.716	178,652
1	9/29/2009	0.2477	20.784	169,790
1	9/30/2009	0.2524	20.863	169,604
1	10/1/2009	0.2411	22.513	186,683
1	10/2/2009	0.2325	20.856	179,414
1	10/3/2009	0.1313	0.598	6,060
1	10/7/2009	0.0181	0.035	3,276
1	10/8/2009	0.103	2.601	27,845
1	10/9/2009	0.2059	18.142	175,119
1	10/10/2009	0.2194	20.806	190,259
1	10/11/2009	0.2098	19.8	188,683
1	10/12/2009	0.2499	24.099	192,840
1	10/13/2009	0.2572	24.66	191,558
1	10/14/2009	0.217	19.215	177,612
1	10/15/2009	0.2197	20.66	188,342
1	10/16/2009	0.2181	16.934	146,061
1	10/17/2009	0.2859	26.442	184,801
1	10/18/2009	0.2393	18.891	157,944
1	10/19/2009	0.2471	22.67	183,876
1	10/20/2009	0.2434	23.219	190,813

1	10/21/2009	0.2457	22.037	178,846
1	10/22/2009	0.2437	23.546	193,233
1	10/23/2009	0.2342	21.505	183,381
1	10/24/2009	0.2778	21.986	164,660
1	10/25/2009	0.261	23.63	180,733
1	10/26/2009	0.282	25.897	181,600
1	10/27/2009	0.2388	22.245	186,229
1	10/28/2009	0.2646	23.03	173,453
1	10/29/2009	0.2612	25.197	192,993
1	10/30/2009	0.2969	25.771	173,152
1	10/31/2009	0.275	20.524	155,484
1	11/1/2009	0.24	20.422	170,338
1	11/2/2009	0.2407	21.915	181,037
1	11/3/2009	0.2439	23.658	193,988
1	11/4/2009	0.2441	24.191	198,227
1	11/5/2009	0.2408	23.14	192,201
1	11/6/2009	0.239	23.424	195,972
1	11/7/2009	0.3008	26.77	179,558
1	11/8/2009	0.2839	27.824	196,035
1	11/9/2009	0.2309	22.044	191,074
1	11/10/2009	0.2232	21.629	193,791
1	11/11/2009	0.2322	21.276	183,505
1	11/12/2009	0.2323	21.877	188,405
1	11/13/2009	0.2235	21.093	188,761
1	11/14/2009	0.2407	19.833	169,629
1	11/15/2009	0.2398	21.074	178,440
1	11/16/2009	0.2416	22.088	182,498
1	11/17/2009	0.2444	22.727	185,298
1	11/18/2009	0.2675	25.5	190,795
1	11/19/2009	0.2644	24.905	187,826
1	11/20/2009	0.2558	25.076	196,091
1	11/21/2009	0.2614	25.879	198,002
1	11/22/2009	0.2866	25.585	180,892
1	11/23/2009	0.2669	25.978	194,669
1	11/24/2009	0.2643	25.777	195,036
1	11/25/2009	0.2674	26.216	196,066
1	11/26/2009	0.2421	22.007	181,702
1	11/27/2009	0.2024	19.373	191,302
1	11/28/2009	0.2262	19.388	176,586
1	11/29/2009	0.2126	21.011	197,657
1	11/30/2009	0.2246	21.342	191,357
1	12/1/2009	0.235	22.887	194,779
1	12/2/2009	0.2278	21.908	192,199
1	12/3/2009	0.2326	23.514	202,177
1	12/4/2009	0.2377	23.785	200,205
1	12/5/2009	0.2578	21.824	175,921
1	12/6/2009	0.2358	22.975	194,875

1	12/7/2009	0.2438	22.599	185,385
1	12/8/2009	0.2312	22.272	192,772
1	12/9/2009	0.2334	22.255	191,311
1	12/10/2009	0.2236	22.199	198,546
1	12/11/2009	0.2138	20.299	190,078
1	12/12/2009	0.2895	23.82	168,420
1	12/13/2009	0.2328	18.793	164,736
1	12/14/2009	0.217	20.137	184,394
1	12/15/2009	0.2241	21.809	194,862
1	12/16/2009	0.2255	21.731	192,781
1	12/17/2009	0.2121	20.822	196,522
1	12/18/2009	0.224	20.335	181,966
1	12/19/2009	0.2375	20.414	175,193
1	12/20/2009	0.2233	21.12	189,243
1	12/21/2009	0.2246	21.168	188,467
1	12/22/2009	0.2485	23.497	188,998
1	12/23/2009	0.2691	26.104	194,235
1	12/24/2009	0.2794	14.639	114,166
1	12/25/2009	0.0621	0.925	15,502
1	12/26/2009	0.2232	20.471	182,723
1	12/27/2009	0.2245	21.517	191,879
1	12/28/2009	0.217	20.65	190,240
1	12/29/2009	0.2149	21.123	196,616
1	12/30/2009	0.2244	21.379	190,648
1	12/31/2009	0.2446	22.456	183,231
1	1/1/2010	0.2255	21.167	187,682
1	1/2/2010	0.2472	21.08	175,457
1	1/3/2010	0.2242	21.432	191,270
1	1/4/2010	0.2109	20.432	193,792
1	1/5/2010	0.2211	21.426	193,808
1	1/6/2010	0.2386	18.882	165,099
1	1/7/2010	0.221	19.644	176,462
1	1/8/2010	0.2114	17.623	163,427
1	1/9/2010	0.2193	20.508	187,241
1	1/10/2010	0.2208	20.749	187,960
1	1/11/2010	0.2365	22.163	187,485
1	1/12/2010	0.2453	23.306	189,615
1	1/13/2010	0.297	28.967	194,558
1	1/14/2010	0.2842	27.53	193,543
1	1/15/2010	0.2856	28.326	198,336
1	1/16/2010	0.2991	25.997	177,113
1	1/17/2010	0.2743	25.113	182,520
1	1/18/2010	0.279	24.438	174,657
1	1/19/2010	0.2733	24.846	181,325
1	1/20/2010	0.2664	23.481	175,532
1	1/21/2010	0.274	24.503	177,916
1	1/22/2010	0.2829	26.412	186,815

1	1/23/2010	0.243	19.837	165,166
1	1/24/2010	0.2338	20.511	175,806
1	1/25/2010	0.2278	22.615	198,554
1	1/26/2010	0.2249	22.198	197,377
1	1/27/2010	0.2165	19.971	184,713
1	1/28/2010	0.2849	27.012	189,575
1	1/29/2010	0.2828	25.113	176,670
1	1/30/2010	0.2876	22.229	154,818
1	1/31/2010	0.2515	22.09	148,725
1	2/1/2010	0.2703	25.648	176,129
1	2/2/2010	0.2992	27.251	182,544
1	2/3/2010	0.275	27.686	201,338
1	2/4/2010	0.2721	27.138	199,542
1	2/5/2010	0.2478	23.519	190,047
1	2/6/2010	0.2328	20.58	182,706
1	2/7/2010	0.224	20.72	187,002
1	2/8/2010	0.2207	21.21	192,460
1	2/9/2010	0.2625	22.6	170,525
1	2/10/2010	0.2496	24.191	193,793
1	2/11/2010	0.2535	24.713	195,079
1	2/12/2010	0.2606	25.127	192,890
1	2/13/2010	0.2875	24.965	175,028
1	2/14/2010	0.2655	25.665	193,162
1	2/15/2010	0.2664	26.05	195,651
1	2/16/2010	0.2698	26.075	193,291
1	2/17/2010	0.2835	27.085	191,050
1	2/18/2010	0.2786	25.657	184,026
1	2/19/2010	0.2704	24.66	184,949
1	2/20/2010	0.105	0.977	10,224
1	3/21/2010	0.0201	0.083	7,244
1	3/22/2010	0.1987	7.368	66,506
1	3/23/2010	0.1843	16.561	181,217
1	3/24/2010	0.1821	18.207	199,792
1	3/25/2010	0.194	18.609	193,014
1	3/26/2010	0.2142	21.415	199,711
1	3/27/2010	0.1965	17.51	184,033
1	3/28/2010	0.1796	17.291	193,052
1	3/29/2010	0.1676	16.833	200,835
1	3/30/2010	0.1735	16.877	195,738
1	3/31/2010	0.1718	17.426	202,869
1	4/1/2010	0.1728	16.812	195,291
1	4/2/2010	0.1737	16.811	194,109
1	4/3/2010	0.1388	4.837	42,477
1	4/4/2010	0.1594	11.931	134,220
1	4/5/2010	0.1843	18.174	197,060
1	4/6/2010	0.1902	19.021	199,982
1	4/7/2010	0.1808	17.778	196,771

1	4/8/2010	0.1835	17.509	191,422
1	4/9/2010	0.1862	17.693	190,318
1	4/10/2010	0.228	19.36	174,659
1	4/11/2010	0.2044	19.104	188,655
1	4/12/2010	0.19	18.486	195,273
1	4/13/2010	0.2028	18.624	187,867
1	4/14/2010	0.2214	22.472	202,716
1	4/15/2010	0.2516	24.652	196,234
1	4/16/2010	0.2648	25.092	189,530
1	4/17/2010	0.2157	17.869	171,836
1	4/18/2010	0.2518	22.823	180,405
1	4/19/2010	0.259	23.98	185,074
1	4/20/2010	0.2578	24.199	187,740
1	4/21/2010	0.2654	25.315	190,730
1	4/22/2010	0.2631	25.777	195,921
1	4/23/2010	0.2647	25.062	189,340
1	4/24/2010	0.2699	21.67	162,829
1	4/25/2010	0.2553	23.076	180,663
1	4/26/2010	0.2689	25.284	187,997
1	4/27/2010	0.2529	24.266	192,112
1	4/28/2010	0.2435	24.092	197,625
1	4/29/2010	0.2153	20.848	193,827
1	4/30/2010	0.2161	21.827	202,101
1	5/1/2010	0.2627	23.583	181,531
1	5/2/2010	0.2089	21.664	207,393
1	5/3/2010	0.25	25.62	205,100
1	5/4/2010	0.2575	25.729	199,527
1	5/5/2010	0.2416	23.278	191,991
1	5/6/2010	0.2315	23.214	200,811
1	5/7/2010	0.2694	27.233	202,258
1	5/8/2010	0.2733	25.744	190,707
1	5/9/2010	0.2963	27.154	184,815
1	5/10/2010	0.2247	22.817	203,258
1	5/11/2010	0.2684	26.112	199,306
1	5/12/2010	0.2552	26.633	208,659
1	5/13/2010	0.2555	25.429	199,001
1	5/14/2010	0.2523	26.851	212,840
1	5/15/2010	0.25	23.115	188,487
1	5/16/2010	0.2388	24.284	203,473
1	5/17/2010	0.2402	24.465	203,525
1	5/18/2010	0.2502	25.344	202,638
1	5/19/2010	0.2603	26.042	199,883
1	5/20/2010	0.2413	24.035	199,037
1	5/21/2010	0.2449	24.816	202,660
1	5/22/2010	0.2607	23.546	184,935
1	5/23/2010	0.2441	26.169	214,435
1	5/24/2010	0.2526	26.032	205,992

1	5/25/2010	0.2518	25.772	204,656
1	5/26/2010	0.2464	24.331	196,980
1	5/27/2010	0.2496	25.909	207,626
1	5/28/2010	0.2353	22.017	185,447
1	5/29/2010	0.2644	23.718	180,639
1	5/30/2010	0.2595	23.648	182,486
1	5/31/2010	0.2593	25.021	191,134
1	6/1/2010	0.2641	27.579	207,957
1	6/2/2010	0.2546	27.177	213,484
1	6/3/2010	0.2455	23.534	189,871
1	6/6/2010	0.1503	11.423	95,868
1	6/7/2010	0.2485	25.341	203,099
1	6/8/2010	0.2484	26.455	212,998
1	6/9/2010	0.2488	25.949	208,623
1	6/10/2010	0.275	29.23	212,646
1	6/11/2010	0.2842	29.996	210,952
1	6/12/2010	0.2451	23.58	192,764
1	6/13/2010	0.2509	26.557	211,620
1	6/14/2010	0.24	25.088	209,081
1	6/15/2010	0.2763	28.133	203,272
1	6/16/2010	0.275	28.614	208,149
1	6/17/2010	0.266	27.845	209,373
1	6/18/2010	0.2703	28.041	207,522
1	6/19/2010	0.2934	27.652	189,156
1	6/20/2010	0.2922	30.563	209,187
1	6/21/2010	0.2885	30.561	211,832
1	6/22/2010	0.2844	28.471	199,716
1	6/23/2010	0.2758	27.324	197,144
1	6/24/2010	0.27	28.11	208,190
1	6/25/2010	0.2548	26.307	206,529
1	6/26/2010	0.2746	25.234	186,579
1	6/27/2010	0.259	26.651	205,554
1	6/28/2010	0.2641	27.109	205,362
1	6/29/2010	0.2663	27.287	205,077
1	6/30/2010	0.2635	27.147	206,030
1	7/1/2010	0.2596	26.917	207,354
1	7/2/2010	0.2391	24.64	206,221
1	7/3/2010	0.2528	22.579	183,539
1	7/4/2010	0.2474	25.063	202,228
1	7/5/2010	0.2432	24.872	204,498
1	7/6/2010	0.282	28.964	205,475
1	7/7/2010	0.2782	28.761	206,738
1	7/8/2010	0.279	29.277	209,878
1	7/9/2010	0.2808	29.026	206,709
1	7/10/2010	0.3021	28.47	188,958
1	7/11/2010	0.2915	29.614	203,030
1	7/12/2010	0.2835	28.878	203,711

1	7/13/2010	0.255	23.689	183,736
1	7/14/2010	0.2803	28.11	200,418
1	7/15/2010	0.2795	28.962	207,259
1	7/16/2010	0.2609	25.521	195,534
1	7/17/2010	0.28	25.098	180,246
1	7/18/2010	0.2653	25.887	194,004
1	7/19/2010	0.2645	26.17	197,810
1	7/20/2010	0.2578	24.882	192,669
1	7/21/2010	0.2676	26.094	194,914
1	7/22/2010	0.2393	22.75	188,229
1	7/23/2010	0.2103	20.808	197,760
1	7/24/2010	0.2269	18.969	175,143
1	7/25/2010	0.2214	21.322	194,389
1	7/26/2010	0.2356	24.52	207,912
1	7/27/2010	0.2179	20.532	187,760
1	7/28/2010	0.2498	22.324	176,755
1	7/29/2010	0.256	25.736	200,983
1	7/30/2010	0.2568	25.573	198,910
1	7/31/2010	0.311	29.639	191,293
1	8/1/2010	0.2794	28.948	207,134
1	8/2/2010	0.2789	28.839	206,544
1	8/3/2010	0.2832	30.087	212,590
1	8/4/2010	0.2669	28.321	212,274
1	8/5/2010	0.2843	28.321	199,293
1	8/6/2010	0.3009	30.435	201,985
1	8/7/2010	0.2324	21.7	188,963
1	8/8/2010	0.2139	21.677	203,123
1	8/9/2010	0.2075	18.951	182,041
1	8/10/2010	0.2226	22.429	201,886
1	8/11/2010	0.2355	19.065	162,431
1	8/12/2010	0.2611	25.678	195,833
1	8/13/2010	0.2678	23.715	180,693
1	8/14/2010	0.2618	20.084	155,737
1	8/15/2010	0.2574	23.858	182,175
1	8/16/2010	0.2257	17.033	148,284
1	8/17/2010	0.2456	22.964	186,131
1	8/18/2010	0.222	18.659	167,918
1	8/19/2010	0.2218	21.829	196,812
1	8/20/2010	0.2172	20.633	189,236
1	8/21/2010	0.2232	20.823	190,519
1	8/22/2010	0.2424	25.208	207,480
1	8/23/2010	0.2075	20.834	200,692
1	8/24/2010	0.2227	22.663	203,579
1	8/25/2010	0.2298	22.997	199,797
1	8/26/2010	0.2856	29.761	208,340
1	8/27/2010	0.2811	29.603	210,589
1	8/28/2010	0.2958	28.791	196,519

1	8/29/2010	0.2801	28.725	205,089
1	8/30/2010	0.2704	28.33	209,586
1	8/31/2010	0.2646	27.699	209,384
1	9/1/2010	0.2722	28.265	207,699
1	9/2/2010	0.2639	27.717	210,090
1	9/3/2010	0.2751	28.493	207,171
1	9/4/2010	0.229	20.452	181,873
1	9/5/2010	0.2362	18.821	166,586
1	9/6/2010	0.2136	19.503	180,968
1	9/7/2010	0.2181	22.5	206,398
1	9/8/2010	0.219	22.125	202,297
1	9/9/2010	0.2172	21.891	201,643
1	9/10/2010	0.2271	23.876	210,145
1	9/11/2010	0.2981	29.211	194,520
1	9/12/2010	0.3042	30.691	201,350
1	9/13/2010	0.2831	27.855	196,057
1	9/14/2010	0.2443	23.41	192,607
1	9/15/2010	0.2952	28.846	193,737
1	9/16/2010	0.2925	30.161	206,219
1	9/17/2010	0.2794	28.594	204,671
1	9/18/2010	0.2954	27.328	189,977
1	9/19/2010	0.2806	27.332	194,854
1	9/20/2010	0.2732	27.685	202,718
1	9/21/2010	0.2832	29.207	206,223
1	9/22/2010	0.2922	30.047	205,699
1	9/23/2010	0.2785	28.874	207,392
1	9/24/2010	0.2737	28.257	206,512
1	9/25/2010	0.294	27.525	188,132
1	9/26/2010	0.2893	27.046	186,762
1	9/27/2010	0.25	22.598	183,103
1	9/28/2010	0.2439	23.748	195,172
1	9/29/2010	0.2505	22.465	185,011
1	9/30/2010	0.2404	21.511	183,748
1	10/1/2010	0.2294	23.508	205,060
1	10/2/2010	0.2288	21.437	188,776
1	10/3/2010	0.2259	21.641	192,327
1	10/4/2010	0.2856	27.984	195,610
1	10/5/2010	0.2834	29.092	205,354
1	10/6/2010	0.2862	28.692	200,593
1	10/7/2010	0.2824	28.298	200,537
1	10/8/2010	0.2802	29.073	207,529
1	10/9/2010	0.292	27.867	190,877
1	10/10/2010	0.2769	28.683	207,054
1	10/11/2010	0.2459	24.448	199,999
1	10/12/2010	0.2136	20.95	195,506
1	10/13/2010	0.2154	21.868	202,773
1	10/14/2010	0.2196	21.985	200,529

1	10/15/2010	0.2204	21.505	195,926
1	10/16/2010	0.2917	27.461	188,175
1	10/17/2010	0.2618	23.545	183,396
1	10/18/2010	0.2446	25.17	205,989
1	10/19/2010	0.2188	20.826	191,391
1	10/20/2010	0.224	22.764	203,360
1	10/21/2010	0.2309	23.088	201,067
1	10/22/2010	0.2318	23.651	204,159
1	10/23/2010	0.235	21.697	186,421
1	10/24/2010	0.24	23.459	196,188
1	10/25/2010	0.2665	22.188	169,915
1	10/26/2010	0.2359	19.292	165,852
1	10/27/2010	0.2318	20.855	180,684
1	10/28/2010	0.2406	22.741	189,539
1	10/29/2010	0.2455	23.099	188,395
1	10/30/2010	0.2967	27.207	185,547
1	10/31/2010	0.2561	21.88	175,138
1	11/1/2010	0.2347	22.033	189,015
1	11/2/2010	0.277	26.873	194,078
1	11/3/2010	0.285	28.206	198,065
1	11/4/2010	0.3434	20.56	124,880
1	11/5/2010	0.241	21.14	172,918
1	11/6/2010	0.2381	21.488	184,218
1	11/7/2010	0.2274	20.738	183,946
1	11/8/2010	0.2383	23.397	196,588
1	11/9/2010	0.2398	22.365	187,077
1	11/10/2010	0.2361	21.876	186,398
1	11/11/2010	0.2535	19.769	154,191
1	11/12/2010	0.2768	27.724	200,178
1	11/13/2010	0.2898	24.397	171,689
1	11/14/2010	0.2768	26.116	188,681
1	11/15/2010	0.2703	25.702	189,586
1	11/16/2010	0.2877	21.164	149,409
1	11/17/2010	0.1694	5.503	55,507
1	11/18/2010	0.2278	20.195	177,298
1	11/19/2010	0.2353	21.078	180,626
1	11/20/2010	0.2288	20.684	183,259
1	11/21/2010	0.2258	21.767	193,751
1	11/22/2010	0.2905	27.242	188,178
1	11/23/2010	0.3445	13.456	80,656
1	11/24/2010	0.2676	8.61	65,010
1	11/25/2010	0.2434	18.831	157,963
1	11/26/2010	0.2239	19.222	170,019
1	11/27/2010	0.2383	21.741	183,949
1	11/28/2010	0.2398	20.67	173,911
1	11/29/2010	0.2239	21.048	187,884
1	11/30/2010	0.2323	22.708	194,543

1	12/1/2010	0.2416	24.592	203,637
1	12/2/2010	0.2433	22.339	184,162
1	12/3/2010	0.2371	24.03	202,866
1	12/4/2010	0.2331	23.785	204,109
1	12/5/2010	0.2478	22.067	184,403
1	12/6/2010	0.2543	26.265	206,875
1	12/7/2010	0.2663	25.039	187,245
1	12/8/2010	0.293	28.38	194,102
1	12/9/2010	0.2817	26.434	183,511
1	12/10/2010	0.2875	27.647	191,913
1	12/11/2010	0.256	22.286	177,015
1	12/12/2010	0.2492	24.616	197,914
1	12/13/2010	0.2475	24.822	200,824
1	12/14/2010	0.2296	19.921	171,815
1	12/15/2010	0.285	27.567	193,842
1	12/16/2010	0.2455	20.802	170,358
1	12/17/2010	0.2324	21.843	190,273
1	12/18/2010	0.2613	21.366	170,576
1	12/19/2010	0.2424	22.605	186,984
1	12/20/2010	0.2312	22.482	194,653
1	12/21/2010	0.23	21.245	185,043
1	12/22/2010	0.2856	25.944	181,207
1	12/23/2010	0.2844	27.014	190,152
1	12/24/2010	0.2795	24.808	177,347
1	12/25/2010	0.2407	19.198	164,425
1	12/26/2010	0.2235	21.217	190,308
1	12/27/2010	0.2313	20.666	179,642
1	12/28/2010	0.2375	21.652	182,546
1	12/29/2010	0.2645	25.449	190,736
1	12/30/2010	0.277	23.855	171,533
1	12/31/2010	0.3026	26.151	173,570
1	1/1/2011	0.2744	21.536	156,218
1	1/2/2011	0.2672	23.105	172,336
1	1/3/2011	0.2753	27	196,242
1	1/4/2011	0.2806	26.048	185,438
1	1/5/2011	0.2575	23.648	183,496
1	1/6/2011	0.2365	22.322	189,487
1	1/7/2011	0.2353	22.8	194,000
1	1/8/2011	0.2947	27.576	186,016
1	1/9/2011	0.3177	31.251	196,676
1	1/10/2011	0.3198	31.702	198,103
1	1/11/2011	0.3328	30.367	182,314
1	1/12/2011	0.3181	32.243	203,185
1	1/13/2011	0.2867	27.99	194,900
1	1/14/2011	0.2786	24.58	173,679
1	1/15/2011	0.327	30.171	187,100
1	1/16/2011	0.3086	30.303	196,273

1	1/17/2011	0.256	26.117	204,260
1	1/18/2011	0.2441	23.742	194,861
1	1/19/2011	0.2426	25.2	207,769
1	1/20/2011	0.2318	24.361	210,154
1	1/21/2011	0.2457	25.702	209,251
1	1/22/2011	0.2451	20.654	171,748
1	1/23/2011	0.2604	24.549	188,781
1	1/24/2011	0.227	21.365	189,609
1	1/25/2011	0.2405	24.748	205,811
1	1/26/2011	0.2602	25.822	198,511
1	1/27/2011	0.2867	25.786	179,872
1	1/28/2011	0.2598	26.364	202,981
1	1/29/2011	0.2598	22.796	176,057
1	1/30/2011	0.2678	24.491	184,992
1	1/31/2011	0.2594	25.458	196,838
1	2/1/2011	0.248	24.14	194,921
1	2/2/2011	0.256	24.036	186,626
1	2/3/2011	0.2923	6.742	50,057
1	2/7/2011	0.0326	0.119	6,602
1	2/8/2011	0.258	14.579	114,382
1	2/9/2011	0.2642	23.684	178,339
1	2/10/2011	0.2757	23.783	172,219
1	2/11/2011	0.2694	25.17	187,353
1	2/12/2011	0.2474	20.674	169,900
1	2/13/2011	0.262	22.12	171,222
1	2/14/2011	0.2597	20.397	158,752
1	2/15/2011	0.2999	22.772	152,588
1	2/16/2011	0.3121	18.583	119,114
1	2/17/2011	0.2927	16.883	117,158
1	2/18/2011	0.2941	19.895	140,530
1	2/19/2011	0.2715	23.768	176,567
1	2/20/2011	0.2998	29.001	191,782
1	2/21/2011	0.3223	29.897	187,466
1	2/22/2011	0.3201	31.697	197,027
1	2/23/2011	0.3143	32.46	206,620
1	2/24/2011	0.3074	31.299	203,713
1	2/25/2011	0.289	28.713	201,221
1	2/26/2011	0.366	0.42	2,297
1	3/11/2011	0.0187	0.06	6,279
1	3/12/2011	0.1579	10.754	90,201
1	3/13/2011	0.2883	29.341	203,713
1	3/14/2011	0.2793	29.347	210,151
1	3/15/2011	0.2819	29.423	208,766
1	3/16/2011	0.2881	29.67	205,998
1	3/17/2011	0.2551	25.673	201,221
1	3/18/2011	0.2693	27.686	205,444
1	3/19/2011	0.2478	24.946	202,814

1	3/20/2011	0.2425	25.152	207,659
1	3/21/2011	0.2491	25.753	206,897
1	3/22/2011	0.2512	25.491	202,952
1	3/23/2011	0.3294	32.169	197,040
1	3/24/2011	0.3284	28.585	171,004
1	3/25/2011	0.3242	33.688	207,489
1	3/26/2011	0.3377	35.203	208,540
1	3/27/2011	0.3066	28.918	191,333
1	3/28/2011	0.2696	25.198	186,586
1	3/29/2011	0.2587	23.697	184,101
1	3/30/2011	0.2491	24.75	199,260
1	3/31/2011	0.2541	24.441	192,974
1	4/1/2011	0.2089	18.767	156,848
1	4/2/2011	0.3048	26.807	177,289
1	4/3/2011	0.3077	30.696	198,991
1	4/4/2011	0.2943	28.607	191,457
1	4/5/2011	0.2855	25.756	177,800
1	4/6/2011	0.251	25.47	203,163
1	4/7/2011	0.2511	25.93	206,684
1	4/8/2011	0.2607	27.166	209,541
1	4/9/2011	0.2617	27.56	210,651
1	4/10/2011	0.3235	30.564	193,483
1	4/11/2011	0.3025	24.518	162,199
1	4/12/2011	0.3081	18.537	120,044
1	4/13/2011	0.3173	26.756	169,180
1	4/14/2011	0.2785	29.024	208,382
1	4/15/2011	0.3225	21.052	135,124
1	4/16/2011	0.3033	23.975	159,188
1	4/17/2011	0.3225	21.95	140,316
1	4/18/2011	0.2923	28.136	193,723
1	4/19/2011	0.2926	27.145	187,623
1	4/20/2011	0.2662	26.325	199,464
1	4/21/2011	0.3068	25.387	166,261
1	4/22/2011	0.3052	27.694	180,982
1	4/23/2011	0.1818	13.913	96,641
1	4/24/2011	0.2565	21.49	146,069
1	4/25/2011	0.3061	25.211	167,085
1	4/26/2011	0.2926	28.505	194,483
1	4/27/2011	0.3103	29.212	187,361
1	4/28/2011	0.3153	33.476	212,167
1	4/29/2011	0.3142	32	202,245
1	4/30/2011	0.3348	31.344	193,614
1	5/1/2011	0.3035	31.286	205,693
1	5/2/2011	0.3157	29.217	188,517
1	5/3/2011	0.2953	30.087	203,771
1	5/4/2011	0.2882	30.358	210,564
1	5/5/2011	0.3253	33.008	203,050

1	5/6/2011	0.3303	32.479	197,656
1	5/7/2011	0.335	31.433	190,510
1	5/8/2011	0.3232	32.219	197,485
1	5/9/2011	0.3485	33.531	190,878
1	5/10/2011	0.3502	36.017	205,098
1	5/11/2011	0.3198	30.162	187,118
1	5/12/2011	0.3328	34.496	206,860
1	5/13/2011	0.3	25.255	166,465
1	5/14/2011	0.2685	22.316	166,620
1	5/15/2011	0.2583	20.237	156,706
1	5/16/2011	0.2401	23.336	195,978
1	5/17/2011	0.245	20.526	167,790
1	5/18/2011	0.3041	29.025	188,581
1	5/19/2011	0.3013	28.953	192,586
1	5/20/2011	0.2849	24.003	174,209
1	5/21/2011	0.3387	19.749	119,185
1	5/22/2011	0.3179	26.546	167,128
1	5/23/2011	0.2817	19.462	138,655
1	5/24/2011	0.2652	12.27	94,238
1	5/25/2011	0.3277	14.403	88,399
1	5/26/2011	0.3134	11.742	75,516
1	5/27/2011	0.2824	18.587	132,303
1	5/28/2011	0.2844	17.518	128,124
1	5/29/2011	0.2762	21.743	158,702
1	5/30/2011	0.2673	25.753	194,432
1	5/31/2011	0.2588	27.233	212,989
1	6/1/2011	0.2501	25.855	209,164
1	6/2/2011	0.2549	26.463	207,806
1	6/3/2011	0.304	33.777	222,247
1	6/4/2011	0.2468	23.901	201,577
1	6/5/2011	0.2215	23.022	194,071
1	6/6/2011	0.2938	17.844	123,104
1	6/7/2011	0.2529	22.972	180,960
1	6/8/2011	0.289	28.385	192,998
1	6/9/2011	0.2639	26.331	198,818
1	6/10/2011	0.2426	22.745	185,207
1	6/11/2011	0.2614	21.274	165,344
1	6/12/2011	0.285	21.684	162,833
1	6/13/2011	0.2448	23.68	192,365
1	6/14/2011	0.2439	24.562	200,470
1	6/15/2011	0.2418	26.31	217,535
1	6/16/2011	0.3014	29.69	196,018
1	6/17/2011	0.3077	31.325	202,696
1	6/18/2011	0.2494	21.733	176,490
1	6/19/2011	0.2443	19.919	162,985
1	6/20/2011	0.2401	17.898	148,992
1	6/21/2011	0.2552	26.63	208,883

1	6/22/2011	0.3066	30.557	198,190
1	6/23/2011	0.2923	27.879	190,172
1	6/24/2011	0.2943	28.55	193,016
1	6/25/2011	0.2772	25.397	190,278
1	6/26/2011	0.2567	26.21	206,105
1	6/27/2011	0.2488	27.561	221,597
1	6/28/2011	0.2837	27.863	194,319
1	6/29/2011	0.2798	26.347	187,317
1	6/30/2011	0.2873	30.244	210,121
1	7/1/2011	0.2909	30.598	210,254
1	7/2/2011	0.2971	32.532	218,892
1	7/3/2011	0.2991	27.738	188,972
1	7/4/2011	0.2654	22.959	174,073
1	7/5/2011	0.2439	23.389	190,364
1	7/6/2011	0.2513	26.535	211,123
1	7/7/2011	0.2504	26.951	215,346
1	7/8/2011	0.2533	27.767	219,197
1	7/9/2011	0.239	24.282	205,122
1	7/10/2011	0.2417	26.837	222,145
1	7/11/2011	0.2405	26.62	221,393
1	7/12/2011	0.2691	28.291	209,935
1	7/13/2011	0.2866	31.379	218,780
1	7/14/2011	0.2852	30.975	217,155
1	7/15/2011	0.2978	32.598	218,739
1	7/16/2011	0.303	30.545	202,319
1	7/17/2011	0.2943	31.621	214,289
1	7/18/2011	0.2935	32.197	219,095
1	7/19/2011	0.2508	26.214	209,355
1	7/20/2011	0.2438	26.822	220,143
1	7/21/2011	0.2373	26.004	219,243
1	7/22/2011	0.2316	25.712	221,899
1	7/23/2011	0.2612	26.251	207,145
1	7/24/2011	0.2442	26.09	214,034
1	7/25/2011	0.2436	25.395	208,556
1	7/26/2011	0.2933	31.12	210,499
1	7/27/2011	0.3134	10.128	66,037
1	7/29/2011	0.089	2.118	20,420
1	7/30/2011	0.2457	19.261	158,945
1	7/31/2011	0.2636	25.89	198,165
1	8/1/2011	0.2543	27.118	215,177
1	8/2/2011	0.2931	30.617	209,369
1	8/3/2011	0.2884	30.395	210,149
1	8/4/2011	0.3111	34.653	222,817
1	8/5/2011	0.3055	33.391	218,715
1	8/6/2011	0.2476	24.84	204,489
1	8/7/2011	0.2378	25.849	217,528
1	8/8/2011	0.24	26.288	219,150

1	8/9/2011	0.2348	25.06	213,851
1	8/10/2011	0.2389	25.277	212,023
1	8/11/2011	0.2506	24.41	196,750
1	8/12/2011	0.2346	24.911	213,060
1	8/13/2011	0.2855	27.835	194,252
1	8/14/2011	0.2836	29.626	207,997
1	8/15/2011	0.2905	28.901	196,583
1	8/16/2011	0.2593	26.475	205,376
1	8/17/2011	0.242	26.494	218,994
1	8/18/2011	0.2462	26.264	213,453
1	8/19/2011	0.246	26.58	216,304
1	8/20/2011	0.3125	31.158	202,466
1	8/21/2011	0.2984	31.718	212,613
1	8/22/2011	0.3041	32.923	216,539
1	8/23/2011	0.3016	32.883	218,035
1	8/24/2011	0.3044	29.698	194,978
1	8/25/2011	0.297	30.825	207,837
1	8/26/2011	0.2936	29.115	198,020
1	8/27/2011	0.3214	30.116	190,500
1	8/28/2011	0.2824	27.764	198,603
1	8/29/2011	0.2455	25.407	207,435
1	8/30/2011	0.3029	31.871	210,147
1	8/31/2011	0.3024	33.783	223,442
1	9/1/2011	0.2995	28.429	188,503
1	9/2/2011	0.275	27.589	198,660
1	9/3/2011	0.2956	29.259	200,164
1	9/4/2011	0.294	30.918	210,336
1	9/5/2011	0.335	28.566	171,987
1	9/6/2011	0.3073	22.283	157,653
1	9/7/2011	0.2566	22.851	181,872
1	9/8/2011	0.2522	23.43	187,528
1	9/9/2011	0.2672	24.381	186,087
1	9/10/2011	0.2612	24.521	192,639
1	9/11/2011	0.2345	24.68	211,851
1	9/12/2011	0.2929	15.006	102,976
1	9/13/2011	0.3017	11.17	75,172
1	9/15/2011	0.0121	0.031	3,566
1	9/16/2011	0.2529	22.791	169,360
1	9/17/2011	0.2808	29.152	208,051
1	9/18/2011	0.2764	28.756	207,730
1	9/19/2011	0.2666	28.215	211,593
1	9/20/2011	0.269	28.224	209,369
1	9/21/2011	0.2565	27.649	215,740
1	9/22/2011	0.2566	27.998	218,256
1	9/23/2011	0.265	26.895	203,117
1	9/24/2011	0.2555	23.691	185,965
1	9/25/2011	0.2568	25.174	195,549

1	9/26/2011	0.2658	26.646	200,705
1	9/27/2011	0.2838	29.077	204,780
1	9/28/2011	0.2901	30.027	207,673
1	9/29/2011	0.3062	27.442	179,335
1	9/30/2011	0.2993	24.304	165,646
1	10/1/2011	0.3272	28.377	172,370
1	10/2/2011	0.332	27.139	167,584
1	10/3/2011	0.299	27.784	185,830
1	10/4/2011	0.2973	26.108	185,301
1	10/5/2011	0.2848	28.83	202,563
1	10/6/2011	0.2912	29.672	203,710
1	10/7/2011	0.2583	20.305	158,190
1	12/1/2011	0.0344	0.276	12,257
1	12/2/2011	0.1488	2.584	19,245
1	12/3/2011	0.2449	7.913	67,100
1	12/4/2011	0.0213	0.064	5,278
1	12/5/2011	0.2395	3.643	27,954
1	12/6/2011	0.1552	11.391	97,526
1	12/7/2011	0.1832	6.469	54,040
1	12/8/2011	0.0355	0.24	12,053
1	12/9/2011	0.1425	4.276	35,345
1	12/10/2011	0.2094	18.036	166,221
1	12/11/2011	0.2645	26.706	201,593
1	12/12/2011	0.3437	27.04	159,061
1	12/13/2011	0.3433	21.816	130,345
1	12/14/2011	0.3019	21.065	140,785
1	12/15/2011	0.2904	22.341	156,132
1	12/16/2011	0.2785	25.628	184,586
1	12/17/2011	0.3318	25.227	154,770
1	12/18/2011	0.2967	26.504	178,319
1	12/19/2011	0.3098	25.612	164,932
1	12/20/2011	0.2955	26.485	178,182
1	12/21/2011	0.2774	23.53	176,338
1	12/22/2011	0.2623	19.466	151,302
1	12/23/2011	0.2683	20.937	163,070
1	12/24/2011	0.2581	18.565	145,510
1	12/25/2011	0.2963	17.234	117,109
1	12/26/2011	0.2589	19.485	156,074
1	12/27/2011	0.2525	18.381	147,026
1	12/28/2011	0.2361	18.315	157,262
1	12/29/2011	0.267	19.695	146,980
1	12/30/2011	0.2305	17.172	148,630
1	12/31/2011	0.2204	15.742	146,090
		Max (tpd) -->	**36.017**	
		Max (lb/hr) -->	**3001.4**	

Note: Dates with no operation/emissions not shown

Unit ID	Date	Avg. NOx Rate (lb/MMBtu)	NOx (tons)	Heat Input (MMBtu)
2	1/1/2009	0.0261	0.091	5,640
2	1/2/2009	0.2909	18.42	127,323
2	1/3/2009	0.2318	13.585	119,933
2	1/8/2009	0.0775	1.118	12,624
2	1/9/2009	0.2739	23.517	171,068
2	1/10/2009	0.2507	20.168	162,382
2	1/11/2009	0.2739	22.223	163,644
2	1/12/2009	0.2975	29.043	193,510
2	1/13/2009	0.2893	26.767	181,728
2	1/14/2009	0.3188	32.754	205,116
2	1/15/2009	0.31	28.395	180,371
2	1/16/2009	0.3048	27.868	176,283
2	1/17/2009	0.2602	25.026	191,525
2	1/18/2009	0.2593	23.665	180,663
2	1/19/2009	0.3101	30.405	194,800
2	1/20/2009	0.3551	35.611	201,033
2	1/21/2009	0.3343	34.302	205,302
2	1/22/2009	0.3221	32.896	204,164
2	1/23/2009	0.3216	31.966	198,290
2	1/24/2009	0.2958	27.507	183,605
2	1/25/2009	0.3155	28.282	178,578
2	1/26/2009	0.2993	28.875	192,705
2	1/27/2009	0.3009	25.29	166,495
2	1/28/2009	0.2567	21.379	167,368
2	1/29/2009	0.2704	22.598	164,099
2	1/30/2009	0.2523	18.045	142,425
2	1/31/2009	0.2298	15.086	129,124
2	2/1/2009	0.2836	22.647	158,168
2	2/2/2009	0.3019	25.355	166,649
2	2/3/2009	0.2946	28.553	193,402
2	2/4/2009	0.2917	27.911	191,143
2	2/5/2009	0.278	24.888	178,569
2	2/6/2009	0.2869	24.119	169,541
2	3/10/2009	0.0153	0.055	5,142
2	3/11/2009	0.0995	2.116	27,663
2	3/12/2009	0.2269	11.877	105,805
2	3/13/2009	0.224	12.707	116,628
2	3/14/2009	0.278	24.624	174,313
2	3/15/2009	0.2862	28.461	198,920
2	3/16/2009	0.2786	23.489	162,301
2	3/17/2009	0.2813	28.246	200,711
2	3/18/2009	0.2543	24.712	192,237
2	3/19/2009	0.2388	22.403	186,664
2	3/20/2009	0.2793	26.931	192,324
2	3/21/2009	0.2939	28.949	196,639

2	3/22/2009	0.3368	25.926	160,754
2	3/23/2009	0.2891	27.445	185,615
2	3/24/2009	0.28	26.217	183,347
2	3/25/2009	0.2845	26.316	183,498
2	3/26/2009	0.2292	17.558	154,379
2	3/27/2009	0.2301	19.644	169,547
2	3/28/2009	0.2328	20.618	174,851
2	3/29/2009	0.2912	22.947	161,137
2	3/30/2009	0.2319	18.375	157,407
2	3/31/2009	0.2632	21.662	165,761
2	4/1/2009	0.2305	19.969	173,539
2	4/2/2009	0.2834	26.598	185,888
2	4/3/2009	0.2948	25.478	178,791
2	4/4/2009	0.2834	26.519	187,224
2	4/5/2009	0.2995	22.771	158,096
2	4/6/2009	0.2886	24.795	170,003
2	4/7/2009	0.2774	22.94	165,933
2	4/8/2009	0.2798	27.927	199,584
2	4/9/2009	0.2935	28.35	192,328
2	4/10/2009	0.2943	29.188	197,666
2	4/11/2009	0.2406	21.521	178,271
2	4/12/2009	0.2444	20.202	170,894
2	4/13/2009	0.2386	23.46	196,569
2	4/14/2009	0.235	21.614	183,468
2	4/15/2009	0.2654	25.425	189,209
2	4/16/2009	0.2962	29.264	197,585
2	4/17/2009	0.3001	29.528	196,034
2	4/18/2009	0.2917	26.649	181,591
2	4/19/2009	0.2607	20.281	163,877
2	4/20/2009	0.2765	20.982	151,331
2	4/21/2009	0.2872	18.688	134,224
2	4/22/2009	0.2946	19.749	140,507
2	4/23/2009	0.2872	20.909	147,977
2	4/24/2009	0.2655	21.91	165,115
2	4/25/2009	0.2919	26.843	185,377
2	4/26/2009	0.3163	26.158	174,199
2	4/27/2009	0.2764	27.239	196,737
2	4/28/2009	0.2998	26.418	179,218
2	4/29/2009	0.2612	25.324	193,188
2	4/30/2009	0.2669	24.279	182,477
2	5/1/2009	0.2713	26.87	197,305
2	5/2/2009	0.2759	25.246	182,506
2	5/3/2009	0.3023	24.906	169,518
2	5/4/2009	0.2453	24.406	199,418
2	5/5/2009	0.2289	22.984	200,712
2	5/6/2009	0.2312	24.118	208,634
2	5/7/2009	0.2237	21.628	192,131

2	5/8/2009	0.2238	20.322	184,264
2	5/10/2009	0.0475	0.316	6,652
2	5/13/2009	0.0345	0.095	5,089
2	5/14/2009	0.2212	15.754	144,287
2	5/15/2009	0.2099	19.947	188,515
2	5/16/2009	0.2342	22.483	192,186
2	5/17/2009	0.2663	17.789	143,453
2	5/18/2009	0.3109	16.009	119,022
2	5/19/2009	0.3356	23.757	148,024
2	5/20/2009	0.3431	27.769	172,398
2	5/21/2009	0.2713	25.308	187,292
2	5/22/2009	0.271	25.287	186,142
2	5/23/2009	0.2786	24.6	177,111
2	5/24/2009	0.2987	22.044	149,976
2	5/25/2009	0.3122	28.598	182,290
2	5/26/2009	0.2694	25.161	187,188
2	5/27/2009	0.2783	27.584	198,031
2	5/28/2009	0.2693	25.369	188,054
2	5/29/2009	0.2698	26.267	194,221
2	5/30/2009	0.2825	23.995	174,613
2	5/31/2009	0.3342	28.272	172,557
2	6/1/2009	0.266	23.483	178,127
2	6/2/2009	0.2611	25.715	196,721
2	6/3/2009	0.2533	22.715	179,806
2	6/4/2009	0.271	20.851	158,037
2	6/5/2009	0.2674	22.602	171,796
2	6/6/2009	0.2957	22.743	162,591
2	6/7/2009	0.2636	21.407	170,189
2	6/8/2009	0.2481	22.267	181,947
2	6/9/2009	0.2329	22.017	189,044
2	6/10/2009	0.2265	21.733	191,665
2	6/11/2009	0.2374	18.931	162,381
2	6/12/2009	0.2573	19.877	155,848
2	6/13/2009	0.2581	21.896	170,331
2	6/14/2009	0.2747	19.471	147,429
2	6/15/2009	0.2846	26.277	182,258
2	6/16/2009	0.2907	25.986	178,046
2	6/17/2009	0.3072	29.88	194,039
2	6/18/2009	0.2996	28.044	186,931
2	6/21/2009	0.1197	4.959	46,582
2	6/22/2009	0.2236	22.416	200,395
2	6/23/2009	0.2248	22.535	200,333
2	6/24/2009	0.2741	27.504	199,998
2	6/25/2009	0.3138	31.309	199,188
2	6/26/2009	0.2556	23.784	184,452
2	6/27/2009	0.2583	24.851	162,343
2	6/28/2009	0.2903	28.691	197,646

2	6/29/2009	0.263	22.635	171,126
2	6/30/2009	0.2483	19.334	151,681
2	7/1/2009	0.2656	23.073	169,900
2	7/2/2009	0.2575	23.22	177,500
2	7/3/2009	0.2675	22.222	166,394
2	7/4/2009	0.273	24.728	179,753
2	7/5/2009	0.2543	20.745	159,592
2	7/6/2009	0.2562	23.265	178,252
2	7/7/2009	0.2721	26.092	190,572
2	7/8/2009	0.3048	29.026	189,384
2	7/9/2009	0.3118	30.494	195,328
2	7/10/2009	0.3191	32.415	202,918
2	7/11/2009	0.3213	30.604	188,437
2	7/12/2009	0.3187	28.733	176,910
2	7/13/2009	0.3282	32.729	199,236
2	7/14/2009	0.2708	25.07	184,893
2	7/15/2009	0.2813	26.429	186,932
2	7/16/2009	0.2845	27.408	191,498
2	7/17/2009	0.2359	19.018	162,426
2	7/18/2009	0.2425	20.145	164,577
2	7/19/2009	0.2653	19.508	155,821
2	7/20/2009	0.236	21.72	184,119
2	7/21/2009	0.22	20.124	183,440
2	7/22/2009	0.274	24.392	173,242
2	7/23/2009	0.3088	30.97	200,132
2	7/24/2009	0.286	26.564	184,917
2	7/25/2009	0.2697	24.839	184,894
2	7/26/2009	0.2895	19.872	142,800
2	7/27/2009	0.2409	19.605	163,263
2	7/28/2009	0.246	20.557	164,855
2	7/29/2009	0.2853	23.79	166,403
2	7/30/2009	0.291	24.573	167,059
2	7/31/2009	0.3055	31.279	204,690
2	8/1/2009	0.2828	25.528	179,649
2	8/2/2009	0.2508	19.842	161,155
2	8/3/2009	0.245	24.245	198,288
2	8/4/2009	0.2352	23.658	201,238
2	8/5/2009	0.2216	20.975	188,904
2	8/6/2009	0.2191	20.001	182,055
2	8/7/2009	0.2285	22.092	192,540
2	8/8/2009	0.2277	23.152	203,064
2	8/9/2009	0.2445	22.201	182,293
2	8/10/2009	0.2472	25.346	204,973
2	8/11/2009	0.2256	22.964	203,497
2	8/12/2009	0.2961	29.01	192,204
2	8/13/2009	0.2277	21.492	188,631
2	8/14/2009	0.2335	23.534	201,382

2	8/15/2009	0.2299	21.944	191,080
2	8/16/2009	0.2366	20.663	179,765
2	8/17/2009	0.2187	21.87	200,005
2	8/18/2009	0.2978	28.635	191,809
2	8/19/2009	0.2924	27.803	189,161
2	8/20/2009	0.2888	26.9	185,739
2	8/21/2009	0.2437	21.693	178,823
2	8/22/2009	0.2332	21.642	186,341
2	8/23/2009	0.2612	19.258	159,475
2	8/24/2009	0.2303	20.179	176,997
2	8/25/2009	0.3071	28.576	186,272
2	8/26/2009	0.2597	24.244	186,079
2	8/27/2009	0.3139	30.067	190,691
2	8/28/2009	0.3126	31.529	201,669
2	8/29/2009	0.3215	31.495	195,088
2	8/30/2009	0.3267	27.579	169,222
2	8/31/2009	0.3178	29.264	183,648
2	9/1/2009	0.3099	27.268	175,096
2	9/2/2009	0.3059	28.038	181,422
2	9/3/2009	0.3375	32.789	193,031
2	9/4/2009	0.3618	36.842	203,599
2	9/5/2009	0.3384	33.023	194,479
2	9/6/2009	0.3513	29.848	169,190
2	9/7/2009	0.3366	29.943	172,742
2	9/8/2009	0.3393	32.53	188,604
2	9/9/2009	0.3634	36.179	198,949
2	9/10/2009	0.3643	36.752	201,548
2	9/11/2009	0.3347	32.879	196,345
2	9/12/2009	0.3207	30.37	188,358
2	9/13/2009	0.3158	25.212	157,901
2	9/14/2009	0.3433	32.589	189,217
2	9/15/2009	0.3474	35.384	203,659
2	9/16/2009	0.3135	30.582	195,154
2	9/17/2009	0.278	28.479	205,009
2	9/18/2009	0.2556	26.107	204,203
2	9/19/2009	0.2477	24.919	200,940
2	9/20/2009	0.24	20.354	179,055
2	9/21/2009	0.2965	29.334	197,473
2	9/22/2009	0.2865	24.363	169,762
2	9/23/2009	0.3193	31.254	194,834
2	9/24/2009	0.2957	29.356	198,015
2	9/25/2009	0.3429	32.891	190,096
2	9/26/2009	0.2707	24.502	181,353
2	9/27/2009	0.3319	29.016	173,398
2	9/28/2009	0.3338	31.934	190,619
2	9/29/2009	0.3264	30.063	181,892
2	9/30/2009	0.3341	31.157	185,729

2	10/1/2009	0.337	33.527	198,295
2	10/2/2009	0.3071	29.155	189,928
2	10/3/2009	0.3392	34.386	202,442
2	10/4/2009	0.3227	28.311	174,891
2	10/5/2009	0.3143	30.416	192,620
2	10/6/2009	0.2634	26.18	198,787
2	10/7/2009	0.2722	27.582	202,631
2	10/8/2009	0.2904	30.102	207,317
2	10/9/2009	0.3225	32.316	200,214
2	10/10/2009	0.3102	31.064	200,417
2	10/11/2009	0.2866	25.449	179,828
2	10/12/2009	0.3364	34.524	205,186
2	10/13/2009	0.3295	33.467	202,938
2	10/14/2009	0.2984	28.168	188,546
2	10/15/2009	0.3007	30.132	200,178
2	10/16/2009	0.2585	24.37	189,105
2	10/17/2009	0.2405	23.248	193,325
2	10/18/2009	0.2327	19.852	172,447
2	10/19/2009	0.2583	21.54	176,853
2	10/20/2009	0.3089	30.936	200,414
2	10/21/2009	0.331	31.573	189,942
2	10/22/2009	0.3215	32.427	201,492
2	10/23/2009	0.3254	31.777	195,004
2	10/24/2009	0.3237	30.929	190,847
2	10/25/2009	0.3014	24.939	173,417
2	10/26/2009	0.2904	28.241	193,625
2	10/27/2009	0.2895	27.138	187,182
2	10/28/2009	0.2762	25.385	183,112
2	10/29/2009	0.3016	24.228	149,851
2	10/30/2009	0.276	24.937	179,381
2	10/31/2009	0.3163	29.015	183,175
2	11/1/2009	0.3	24.027	160,652
2	11/2/2009	0.2995	28.419	189,147
2	11/3/2009	0.2779	26.764	191,721
2	11/4/2009	0.3273	32.177	196,367
2	11/5/2009	0.3008	28.209	187,854
2	11/6/2009	0.2773	26.957	194,014
2	11/7/2009	0.239	24.316	203,639
2	11/8/2009	0.2415	20.624	179,056
2	11/9/2009	0.2334	22.196	191,275
2	11/10/2009	0.274	25.86	188,887
2	11/11/2009	0.2899	25.937	177,459
2	11/12/2009	0.2822	26.204	185,163
2	11/13/2009	0.3457	33.076	191,030
2	11/14/2009	0.308	26.008	167,792
2	11/15/2009	0.2969	22.156	154,028
2	11/16/2009	0.303	28.564	186,117

2	11/17/2009	0.2463	21.708	176,444
2	11/18/2009	0.2287	20.859	182,735
2	11/19/2009	0.257	23.372	182,126
2	11/20/2009	0.3081	29.036	188,264
2	11/21/2009	0.3112	31.302	200,799
2	11/22/2009	0.2751	24.259	182,490
2	11/23/2009	0.2678	25.736	190,654
2	11/24/2009	0.283	23.623	176,602
2	11/25/2009	0.2725	27.097	198,807
2	11/26/2009	0.2737	25.751	186,850
2	11/27/2009	0.2691	24.821	182,788
2	11/28/2009	0.2781	27.448	197,275
2	11/29/2009	0.2995	26.176	176,650
2	11/30/2009	0.2893	27.559	188,729
2	12/1/2009	0.263	25.754	195,438
2	12/2/2009	0.2288	22.158	193,764
2	12/3/2009	0.2292	22.967	200,612
2	12/4/2009	0.2789	28.516	204,516
2	12/5/2009	0.3279	33.185	202,289
2	12/6/2009	0.3362	30.336	181,762
2	12/7/2009	0.2911	23.975	163,918
2	12/8/2009	0.3119	13.806	89,495
2	12/12/2009	0.1133	2.242	17,812
2	12/13/2009	0.3005	9.515	64,247
2	12/15/2009	0.0715	0.495	7,631
2	12/16/2009	0.3058	13.259	87,248
2	12/17/2009	0.2774	24.817	179,647
2	12/18/2009	0.2795	23.795	170,154
2	12/19/2009	0.2925	26.9	183,803
2	12/20/2009	0.3163	26.804	169,918
2	12/21/2009	0.3035	27.058	176,287
2	12/22/2009	0.3173	29.349	183,895
2	12/23/2009	0.3085	28.641	184,277
2	12/24/2009	0.3026	23.362	151,431
2	12/25/2009	0.2614	20.029	138,839
2	12/26/2009	0.2884	26.201	181,269
2	12/27/2009	0.3037	25.434	172,918
2	12/28/2009	0.2686	25.538	190,783
2	12/29/2009	0.2632	24.618	187,058
2	12/30/2009	0.2595	24.177	185,973
2	12/31/2009	0.2488	20.416	164,415
2	1/1/2010	0.2521	21.984	175,045
2	1/2/2010	0.2541	25.184	198,140
2	1/3/2010	0.2991	26.232	177,269
2	1/4/2010	0.3008	29.406	195,488
2	1/5/2010	0.3034	29.976	197,637
2	1/6/2010	0.2983	23.951	161,388

2	1/7/2010	0.2696	23.191	171,608
2	1/8/2010	0.267	27.171	203,605
2	1/9/2010	0.259	24.768	190,624
2	1/10/2010	0.28	23.223	174,232
2	1/11/2010	0.2847	26.609	186,798
2	1/12/2010	0.2849	12.514	87,786
2	1/13/2010	0.0186	0.024	2,204
2	1/14/2010	0.2851	23.986	147,505
2	1/15/2010	0.3113	31.803	204,470
2	1/16/2010	0.2878	28.004	194,510
2	1/17/2010	0.3285	26.02	158,205
2	1/18/2010	0.3239	28.176	173,134
2	1/19/2010	0.3114	27.115	171,179
2	1/20/2010	0.2508	20.844	166,137
2	1/21/2010	0.2464	21.427	175,286
2	1/22/2010	0.2232	19.947	179,534
2	1/23/2010	0.2739	23.923	172,387
2	1/24/2010	0.2533	19.566	159,630
2	1/25/2010	0.23	21.699	188,704
2	1/26/2010	0.2524	24.197	190,859
2	1/27/2010	0.2611	22.576	171,951
2	1/28/2010	0.3136	26.415	167,979
2	1/29/2010	0.274	23.494	171,604
2	1/30/2010	0.2962	26.224	177,073
2	1/31/2010	0.2905	22.917	157,574
2	2/1/2010	0.3446	29.991	172,425
2	2/2/2010	0.3399	27.803	162,876
2	2/3/2010	0.3475	32.646	187,540
2	2/4/2010	0.366	34.608	189,024
2	2/5/2010	0.3118	26.923	172,586
2	2/6/2010	0.3215	31.463	195,644
2	2/7/2010	0.2856	23.847	171,558
2	2/8/2010	0.2714	26.051	191,688
2	2/9/2010	0.2904	22.913	161,523
2	2/10/2010	0.274	25.86	188,792
2	2/11/2010	0.3164	29.867	187,058
2	2/12/2010	0.3386	32.637	192,683
2	2/13/2010	0.3157	29.228	184,452
2	2/14/2010	0.3246	27.164	168,702
2	2/15/2010	0.3329	33.142	199,022
2	2/16/2010	0.3281	30.89	187,869
2	2/17/2010	0.3458	32.105	184,900
2	2/18/2010	0.3348	30.135	178,528
2	2/19/2010	0.2944	26.965	181,186
2	2/20/2010	0.2753	26.523	192,646
2	2/21/2010	0.2781	22.728	167,967
2	2/22/2010	0.3088	26.762	171,561

2	2/23/2010	0.2846	25.187	176,544
2	2/24/2010	0.2874	25.997	180,771
2	2/25/2010	0.2931	26.44	180,272
2	2/26/2010	0.2967	27.438	184,193
2	2/27/2010	0.289	27.136	187,376
2	2/28/2010	0.3167	25.16	164,061
2	3/1/2010	0.299	22.904	157,411
2	3/2/2010	0.314	30.757	195,772
2	3/3/2010	0.3001	26.325	174,761
2	3/4/2010	0.368	32.709	176,014
2	3/5/2010	0.375	34.798	184,149
2	3/6/2010	0.3696	34.14	183,305
2	3/7/2010	0.3727	34.272	182,926
2	3/8/2010	0.3644	35.184	192,521
2	3/9/2010	0.3495	33.952	193,746
2	3/10/2010	0.3603	36.566	202,397
2	3/11/2010	0.3514	34.602	196,089
2	3/12/2010	0.3642	34.605	189,238
2	3/13/2010	0.3768	35.512	187,053
2	3/14/2010	0.3635	31.076	171,359
2	3/15/2010	0.3218	29.648	183,534
2	3/16/2010	0.3101	28.696	184,617
2	3/17/2010	0.3079	29.313	190,207
2	3/18/2010	0.3283	32.476	197,363
2	3/19/2010	0.3117	30.682	196,351
2	3/20/2010	0.302	26.599	176,023
2	3/21/2010	0.3317	29.287	179,193
2	3/22/2010	0.3054	28.434	185,702
2	3/23/2010	0.2925	24.976	170,091
2	3/24/2010	0.3304	32.319	193,083
2	3/25/2010	0.3379	32.485	189,060
2	3/26/2010	0.3578	35.405	197,427
2	3/27/2010	0.373	37.857	203,107
2	3/28/2010	0.3594	31.488	175,683
2	3/29/2010	0.3452	33.909	196,164
2	3/30/2010	0.3747	36.331	193,829
2	3/31/2010	0.335	32.242	191,293
2	4/1/2010	0.3479	33.54	191,858
2	4/2/2010	0.3054	25.083	164,350
2	4/21/2010	0.0104	0.009	1,248
2	4/22/2010	0.1424	5.172	47,139
2	4/23/2010	0.2579	23.589	182,271
2	4/24/2010	0.2622	23.872	182,387
2	4/25/2010	0.3231	23.56	154,666
2	4/26/2010	0.306	29.095	190,300
2	4/27/2010	0.3617	33.912	187,710
2	4/28/2010	0.3753	34.644	183,603

2	4/29/2010	0.3645	32.248	176,285
2	4/30/2010	0.3723	36.861	197,950
2	5/1/2010	0.367	37.547	204,578
2	5/2/2010	0.3828	35.725	187,772
2	5/3/2010	0.3332	33.052	198,238
2	5/4/2010	0.3265	30.152	183,692
2	5/5/2010	0.2584	22.273	172,845
2	5/6/2010	0.2874	26.371	183,523
2	5/7/2010	0.3903	40.035	205,043
2	5/8/2010	0.4003	39.405	198,799
2	5/9/2010	0.4328	35.521	170,135
2	5/10/2010	0.3978	39.861	200,328
2	5/11/2010	0.3931	40.6	206,565
2	5/12/2010	0.388	40.227	207,331
2	5/13/2010	0.4002	41.74	208,549
2	5/14/2010	0.4039	42.329	209,606
2	5/15/2010	0.4003	41.404	206,779
2	5/16/2010	0.3858	34.968	181,387
2	5/17/2010	0.359	35.109	194,245
2	5/18/2010	0.3375	32.519	191,826
2	5/19/2010	0.3555	32.992	184,593
2	5/20/2010	0.3539	23.745	141,069
2	5/21/2010	0.266	24.74	185,979
2	5/22/2010	0.2758	24.289	177,848
2	5/23/2010	0.3413	30.208	175,857
2	5/24/2010	0.3102	28.437	182,297
2	5/25/2010	0.3129	28.355	181,153
2	5/26/2010	0.309	26.721	173,220
2	5/27/2010	0.307	29.872	193,938
2	5/28/2010	0.2945	25.802	172,520
2	5/29/2010	0.2803	24.142	174,728
2	5/30/2010	0.3133	24.148	162,494
2	5/31/2010	0.3765	34.825	186,096
2	6/1/2010	0.3768	37.764	199,921
2	6/2/2010	0.373	38.857	208,101
2	6/3/2010	0.3377	33.463	197,657
2	6/4/2010	0.3548	37.292	210,092
2	6/5/2010	0.3643	37.882	207,525
2	6/6/2010	0.3784	36.735	190,765
2	6/7/2010	0.3485	33.179	186,705
2	6/8/2010	0.392	40.222	205,035
2	6/9/2010	0.3822	38.475	200,887
2	6/10/2010	0.3068	30.981	200,751
2	6/11/2010	0.2801	28.255	201,667
2	6/12/2010	0.2662	26.587	199,525
2	6/13/2010	0.2632	23.522	178,654
2	6/14/2010	0.3279	31.576	192,221

2	6/15/2010	0.4133	41.545	200,266
2	6/16/2010	0.4036	41.298	204,473
2	6/17/2010	0.3988	40.592	203,371
2	6/18/2010	0.3715	37.442	201,230
2	6/19/2010	0.3702	37.421	201,635
2	6/20/2010	0.3685	34.684	181,864
2	6/21/2010	0.3697	38.138	206,264
2	6/22/2010	0.3138	29.065	182,869
2	6/23/2010	0.3401	32.751	191,169
2	6/24/2010	0.354	35.952	203,054
2	6/25/2010	0.362	36.045	198,253
2	6/26/2010	0.3605	35.497	195,790
2	6/27/2010	0.358	31.223	173,774
2	6/28/2010	0.3546	35.884	202,169
2	6/29/2010	0.346	33.691	193,606
2	6/30/2010	0.3413	33.914	197,055
2	7/1/2010	0.3533	36.572	206,953
2	7/2/2010	0.3557	36.588	205,608
2	7/3/2010	0.3384	32.9	192,412
2	7/4/2010	0.3551	14.261	80,752
2	7/6/2010	0.1452	5.573	49,282
2	7/7/2010	0.2467	17.715	140,569
2	7/10/2010	0.108	3.371	35,086
2	7/11/2010	0.235	22.931	194,447
2	7/12/2010	0.2325	22.063	188,786
2	7/13/2010	0.2195	19.448	175,188
2	7/14/2010	0.2428	23.049	188,608
2	7/15/2010	0.3083	30.652	198,278
2	7/16/2010	0.326	30.626	187,183
2	7/17/2010	0.3212	29.628	182,888
2	7/18/2010	0.3038	25.898	168,068
2	7/19/2010	0.2688	25.087	186,290
2	7/20/2010	0.279	25.228	179,195
2	7/21/2010	0.2851	26.858	187,148
2	7/22/2010	0.2703	25.008	182,559
2	7/23/2010	0.2768	26.549	190,507
2	7/24/2010	0.2814	26.978	189,979
2	7/25/2010	0.3176	27.256	170,903
2	7/26/2010	0.3116	31.933	204,884
2	7/27/2010	0.2922	26.244	177,889
2	7/28/2010	0.3106	26.435	168,005
2	7/29/2010	0.3374	32.237	190,341
2	7/30/2010	0.3345	32.409	192,843
2	7/31/2010	0.3568	35.895	200,721
2	8/1/2010	0.3287	30	181,805
2	8/2/2010	0.3021	27.242	165,631
2	8/3/2010	0.0843	3.155	34,642

2	8/4/2010	0.2788	23.472	165,844
2	8/5/2010	0.288	24.484	169,998
2	8/6/2010	0.3184	30.386	188,776
2	8/7/2010	0.3336	33.039	197,750
2	8/8/2010	0.3155	29.241	181,162
2	8/9/2010	0.2735	24.581	173,678
2	8/10/2010	0.2764	26.072	187,917
2	8/11/2010	0.292	21.984	148,836
2	8/12/2010	0.2346	21.782	184,976
2	8/13/2010	0.2312	21.354	183,762
2	8/14/2010	0.2738	25.002	180,481
2	8/15/2010	0.3087	28.549	181,951
2	8/16/2010	0.268	23.016	166,550
2	8/17/2010	0.2336	19.862	168,430
2	8/18/2010	0.2405	20.847	170,012
2	8/19/2010	0.2278	21.202	184,826
2	8/20/2010	0.2172	19.364	177,073
2	8/21/2010	0.2313	20.219	175,695
2	8/22/2010	0.3024	22.011	151,000
2	8/23/2010	0.3017	23.994	162,738
2	8/24/2010	0.3201	29.647	183,312
2	8/25/2010	0.3027	29.621	194,079
2	8/26/2010	0.2993	13.546	93,683
2	8/28/2010	0.0992	1.178	9,671
2	8/29/2010	0.2742	25.988	187,043
2	8/30/2010	0.3024	31.544	208,567
2	8/31/2010	0.2914	29.6	202,961
2	9/1/2010	0.3032	31.274	206,243
2	9/2/2010	0.2655	26.697	200,547
2	9/3/2010	0.2697	25.059	186,800
2	9/4/2010	0.2585	22.862	176,069
2	9/5/2010	0.331	26.176	157,180
2	9/6/2010	0.312	28.411	175,000
2	9/7/2010	0.3131	31.378	200,025
2	9/8/2010	0.3125	30.693	195,640
2	9/9/2010	0.3145	30.443	192,209
2	9/10/2010	0.3163	31.898	201,819
2	9/11/2010	0.2995	31.21	208,424
2	9/12/2010	0.2738	24.756	180,088
2	9/13/2010	0.2593	23.663	180,788
2	9/14/2010	0.2643	24.632	183,553
2	9/15/2010	0.2785	26.015	184,117
2	9/16/2010	0.2548	24.886	194,499
2	9/17/2010	0.2407	23.854	197,457
2	9/18/2010	0.2501	24.501	195,124
2	9/19/2010	0.2547	20.716	165,500
2	9/20/2010	0.28	26.703	189,739

2	9/21/2010	0.3073	30.549	197,237
2	9/22/2010	0.3044	31.192	204,795
2	9/23/2010	0.2878	29.327	203,673
2	9/24/2010	0.2917	29.842	204,519
2	9/25/2010	0.3368	34.531	205,023
2	9/26/2010	0.3225	25.374	157,556
2	9/27/2010	0.343	30.288	174,395
2	9/28/2010	0.3529	33.819	189,660
2	9/29/2010	0.337	31.985	188,700
2	9/30/2010	0.3067	29.497	190,706
2	10/1/2010	0.3061	26.78	173,646
2	12/1/2010	0.045	0.104	4,636
2	12/2/2010	0.0236	0.135	9,467
2	12/3/2010	0.0877	1.465	18,170
2	12/4/2010	0.104	2.504	23,515
2	12/5/2010	0.2113	6.47	69,803
2	12/6/2010	0.0967	2.243	20,772
2	12/7/2010	0.2328	19.758	169,934
2	12/8/2010	0.2653	22.339	170,105
2	12/9/2010	0.2912	26.479	182,383
2	12/10/2010	0.3654	33.078	180,526
2	12/11/2010	0.3696	32.651	175,081
2	12/12/2010	0.3963	34.441	175,418
2	12/13/2010	0.399	37.477	187,689
2	12/14/2010	0.3696	35.364	191,113
2	12/15/2010	0.336	30.552	177,027
2	12/16/2010	0.3313	29.197	173,761
2	12/17/2010	0.2907	26.929	186,977
2	12/18/2010	0.2787	24.665	179,379
2	12/19/2010	0.3178	26.705	168,255
2	12/20/2010	0.349	33.694	192,951
2	12/21/2010	0.3601	32.432	178,474
2	12/22/2010	0.3515	30.947	175,259
2	12/23/2010	0.351	32.509	184,333
2	12/24/2010	0.2968	22.214	134,210
2	12/25/2010	0.3695	28.806	155,197
2	12/26/2010	0.3838	31.738	167,463
2	12/27/2010	0.3962	33.913	172,104
2	12/28/2010	0.3877	32.717	169,848
2	12/29/2010	0.374	32.493	175,121
2	12/30/2010	0.3763	17.001	92,260
2	1/1/2011	0.1571	10.258	72,888
2	1/2/2011	0.3065	24.754	159,372
2	1/3/2011	0.3377	31.976	188,868
2	1/4/2011	0.3243	29	178,447
2	1/5/2011	0.3359	31.322	186,552
2	1/6/2011	0.3528	32.887	186,140

2	1/7/2011	0.3586	33.09	184,333
2	1/8/2011	0.3365	31.695	188,497
2	1/9/2011	0.3695	32.573	178,845
2	1/10/2011	0.3815	37.065	194,270
2	1/11/2011	0.322	27.342	169,244
2	1/12/2011	0.2904	26.611	182,779
2	1/13/2011	0.329	28.225	171,284
2	1/14/2011	0.3639	29.033	157,835
2	1/15/2011	0.3727	34.019	182,470
2	1/16/2011	0.3495	29.224	167,817
2	1/17/2011	0.3616	35.227	194,763
2	1/18/2011	0.3418	31.47	183,364
2	1/19/2011	0.3505	34.12	194,647
2	1/20/2011	0.362	35.962	198,712
2	1/21/2011	0.409	38.632	188,608
2	1/22/2011	0.3447	29.003	166,832
2	1/23/2011	0.2647	20.198	156,556
2	1/24/2011	0.3425	31.143	178,516
2	1/25/2011	0.3683	35.628	193,152
2	1/26/2011	0.3587	34.163	189,917
2	1/27/2011	0.327	28.503	172,541
2	1/28/2011	0.3474	33.637	193,289
2	1/29/2011	0.2487	21.766	175,190
2	1/30/2011	0.2694	21.502	162,375
2	1/31/2011	0.2805	26.358	187,686
2	2/1/2011	0.2641	25.027	189,268
2	2/2/2011	0.2776	24.727	179,526
2	2/3/2011	0.2923	28.113	191,589
2	2/4/2011	0.3581	36.424	203,281
2	2/5/2011	0.3545	32.365	181,344
2	2/6/2011	0.3216	26.366	162,975
2	2/7/2011	0.3342	32.138	191,591
2	2/8/2011	0.3262	29.09	176,917
2	2/9/2011	0.329	27.564	167,571
2	2/10/2011	0.3225	25.494	157,562
2	2/11/2011	0.3317	29.545	176,463
2	2/12/2011	0.3191	27.466	169,020
2	2/13/2011	0.2287	16.557	134,415
2	2/14/2011	0.2986	22.494	148,370
2	2/15/2011	0.2849	19.686	139,767
2	2/16/2011	0.2948	15.505	106,012
2	2/17/2011	0.2732	14.729	111,337
2	2/18/2011	0.2881	19.392	135,793
2	2/19/2011	0.331	26.26	162,383
2	2/20/2011	0.3196	28.728	179,729
2	2/21/2011	0.3105	29.272	185,021
2	2/22/2011	0.3304	29.663	177,386

2	2/23/2011	0.3506	35.712	203,253
2	2/24/2011	0.3146	31.055	194,571
2	2/25/2011	0.2811	28.443	202,408
2	2/26/2011	0.2765	28.378	205,295
2	2/27/2011	0.2891	27.658	189,608
2	2/28/2011	0.3297	34.86	211,352
2	3/1/2011	0.3283	33.836	206,093
2	3/2/2011	0.331	34.265	206,423
2	3/3/2011	0.3394	35.523	209,307
2	3/4/2011	0.3215	30.34	188,099
2	3/5/2011	0.3319	29.637	178,607
2	3/6/2011	0.3313	27.632	169,866
2	3/7/2011	0.3144	32.563	206,953
2	3/8/2011	0.3067	32.381	211,010
2	3/9/2011	0.3152	31.182	197,610
2	3/10/2011	0.3255	30.724	188,717
2	3/11/2011	0.3295	34.078	206,650
2	3/12/2011	0.3235	34.456	213,036
2	3/13/2011	0.3058	24.608	162,616
2	3/14/2011	0.3025	30.474	199,841
2	3/15/2011	0.2844	26.545	185,436
2	3/16/2011	0.2795	25.471	181,160
2	3/17/2011	0.2815	22.485	158,614
2	3/18/2011	0.292	28.045	192,123
2	3/19/2011	0.3094	32.343	208,308
2	3/20/2011	0.3246	30.831	189,882
2	3/21/2011	0.3083	30.126	194,306
2	3/22/2011	0.3078	28.047	181,559
2	3/23/2011	0.3182	31.24	196,293
2	3/24/2011	0.3351	32.411	192,495
2	3/25/2011	0.3134	25.287	161,512
2	4/22/2011	0.0154	0.032	3,347
2	4/23/2011	0.0797	0.905	10,938
2	4/24/2011	0.2057	6.768	47,080
2	4/25/2011	0.4353	14.765	67,630
2	4/26/2011	0.4074	17.319	90,046
2	4/27/2011	0.3159	26.349	167,264
2	4/28/2011	0.3023	29.551	195,195
2	4/29/2011	0.2912	27.205	187,004
2	4/30/2011	0.2893	27.584	190,167
2	5/1/2011	0.2915	27.14	191,320
2	5/2/2011	0.3033	26.229	174,501
2	5/3/2011	0.2965	28.338	190,403
2	5/4/2011	0.2855	27.677	193,587
2	5/5/2011	0.3054	25.994	175,667
2	5/6/2011	0.3395	20.327	131,417
2	5/7/2011	0.2989	26.32	176,429

2	5/8/2011	0.2846	26.157	181,568
2	5/9/2011	0.2891	24.19	166,892
2	5/10/2011	0.297	27.609	184,996
2	5/11/2011	0.2976	24.67	165,855
2	5/12/2011	0.3067	30.139	195,742
2	5/13/2011	0.2613	18.901	143,927
2	5/14/2011	0.276	21.857	158,210
2	5/15/2011	0.2631	18.014	139,159
2	5/16/2011	0.2928	27.122	183,308
2	5/17/2011	0.2739	22.106	158,795
2	5/18/2011	0.2705	23.72	174,718
2	5/19/2011	0.2911	26.385	179,383
2	5/20/2011	0.2539	20.339	159,868
2	5/21/2011	0.2578	12.945	101,852
2	5/22/2011	0.2976	21.231	144,917
2	5/23/2011	0.2485	14.69	118,399
2	5/24/2011	0.3088	12.364	80,878
2	5/25/2011	0.2932	11.129	76,148
2	5/26/2011	0.3034	10.596	69,987
2	5/27/2011	0.2583	14.89	120,281
2	5/28/2011	0.32	16.437	111,238
2	5/29/2011	0.2447	15.595	130,302
2	5/30/2011	0.2413	20.953	170,818
2	5/31/2011	0.2467	24.483	196,530
2	6/1/2011	0.2744	27.395	196,527
2	6/2/2011	0.2744	26.665	192,143
2	6/3/2011	0.2734	28.35	206,952
2	6/4/2011	0.2702	27.107	199,470
2	6/5/2011	0.2429	14.817	122,241
2	6/6/2011	0.2496	13.002	107,680
2	6/7/2011	0.2536	21.797	167,955
2	6/8/2011	0.268	25.231	184,359
2	6/9/2011	0.2729	26.915	194,932
2	6/10/2011	0.3011	29.11	190,674
2	6/11/2011	0.2943	27.653	184,465
2	6/12/2011	0.2657	19.515	156,987
2	6/13/2011	0.2168	19.877	183,027
2	6/14/2011	0.2618	24.78	185,435
2	6/15/2011	0.2891	29.903	206,659
2	6/16/2011	0.2811	27.153	191,163
2	6/17/2011	0.2731	25.534	185,428
2	6/18/2011	0.2508	22.435	175,735
2	6/19/2011	0.2364	15.654	134,013
2	6/20/2011	0.2294	14.844	130,187
2	6/21/2011	0.2589	25.915	199,965
2	6/22/2011	0.2662	24.749	183,686
2	6/23/2011	0.261	22.766	173,460

2	6/24/2011	0.2989	27.056	177,380
2	6/25/2011	0.3237	30.516	185,524
2	6/26/2011	0.3334	30.913	182,575
2	6/27/2011	0.3429	35.861	208,930
2	6/28/2011	0.294	25.958	174,332
2	6/29/2011	0.2607	22.085	171,964
2	6/30/2011	0.2809	27.622	195,290
2	7/1/2011	0.288	28.731	198,248
2	7/2/2011	0.1999	9.025	61,606
2	7/3/2011	0.2851	28.029	195,550
2	7/4/2011	0.268	21.373	157,070
2	7/5/2011	0.288	25.499	176,014
2	7/6/2011	0.235	23.654	200,501
2	7/7/2011	0.3074	31.39	203,619
2	7/8/2011	0.3149	31.906	200,271
2	7/9/2011	0.3007	27.847	178,256
2	7/10/2011	0.3209	27.654	169,295
2	7/11/2011	0.3645	31.83	178,807
2	7/12/2011	0.2723	24.976	181,806
2	7/13/2011	0.3083	31.829	205,909
2	7/14/2011	0.2963	30.862	208,357
2	7/15/2011	0.3132	32.633	207,754
2	7/16/2011	0.3098	32.203	207,288
2	7/17/2011	0.301	28.777	190,890
2	7/18/2011	0.3318	34.52	207,540
2	7/19/2011	0.3313	33.476	198,487
2	7/20/2011	0.3009	30.804	204,046
2	7/21/2011	0.3122	31.825	202,267
2	7/22/2011	0.3216	33.074	205,062
2	7/23/2011	0.2972	30.875	207,394
2	7/24/2011	0.3365	31.384	186,061
2	7/25/2011	0.3251	31.846	193,676
2	7/26/2011	0.3286	32.634	196,129
2	7/27/2011	0.3365	34.355	201,593
2	7/28/2011	0.3529	37.867	214,033
2	7/29/2011	0.2943	26.439	174,026
2	7/30/2011	0.3167	29.456	178,259
2	7/31/2011	0.3233	30.134	183,246
2	8/1/2011	0.3192	32.162	199,254
2	8/2/2011	0.2609	25.231	192,635
2	8/3/2011	0.2618	25.831	194,914
2	8/4/2011	0.2329	24.194	207,737
2	8/5/2011	0.2261	23.17	204,342
2	8/6/2011	0.2253	23.26	206,213
2	8/7/2011	0.2264	21.331	188,936
2	8/8/2011	0.2853	29.578	206,554
2	8/9/2011	0.2811	28.673	202,776

2	8/10/2011	0.2896	29.131	199,345
2	8/11/2011	0.252	22.855	179,447
2	8/12/2011	0.2611	26.332	200,232
2	8/13/2011	0.2598	25.658	197,416
2	8/14/2011	0.2565	22.782	178,243
2	8/15/2011	0.2477	22.743	183,781
2	8/16/2011	0.2086	19.929	190,837
2	8/17/2011	0.2208	23.255	210,147
2	8/18/2011	0.2521	25.62	202,877
2	8/19/2011	0.2647	27.012	204,403
2	8/20/2011	0.2563	26.25	204,545
2	8/21/2011	0.2664	24.956	186,682
2	8/22/2011	0.2675	27.336	203,535
2	8/23/2011	0.2676	27.43	203,865
2	8/24/2011	0.2668	23.601	178,100
2	8/25/2011	0.2871	28.338	196,837
2	8/26/2011	0.2703	24.915	185,898
2	8/27/2011	0.2457	23.195	189,383
2	8/28/2011	0.2696	22.77	176,413
2	8/29/2011	0.2583	25.34	196,451
2	8/30/2011	0.2771	27.346	197,920
2	8/31/2011	0.2656	28.467	214,333
2	9/1/2011	0.2654	23.516	175,562
2	9/2/2011	0.2482	23.565	187,428
2	9/3/2011	0.2916	30.884	211,687
2	9/4/2011	0.2594	24.55	189,483
2	9/5/2011	0.2502	20.05	161,186
2	9/6/2011	0.2585	20.204	155,925
2	9/7/2011	0.2793	23.578	172,454
2	9/8/2011	0.2599	23.223	178,486
2	9/9/2011	0.2633	22.618	175,494
2	9/10/2011	0.2599	24.196	186,193
2	9/11/2011	0.2642	24.619	187,124
2	9/12/2011	0.247	22.818	184,261
2	9/13/2011	0.246	21.46	174,038
2	9/14/2011	0.2328	19.757	169,212
2	9/15/2011	0.2435	23.005	188,691
2	9/16/2011	0.2602	24.435	186,465
2	9/17/2011	0.2682	26.451	196,960
2	9/18/2011	0.3064	28.174	184,043
2	9/19/2011	0.2624	7.302	55,153
2	9/22/2011	0.134	5.352	44,509
2	9/23/2011	0.3209	31.305	192,018
2	9/24/2011	0.304	28.682	184,634
2	9/25/2011	0.3203	28.745	174,812
2	9/26/2011	0.3344	32.405	192,834
2	9/27/2011	0.3165	31.052	194,835

2	9/28/2011	0.3546	35.064	196,437
2	9/29/2011	0.3133	26.285	165,518
2	9/30/2011	0.3222	25.44	156,812
2	10/1/2011	0.318	26.529	163,164
2	10/2/2011	0.3493	26.624	153,355
2	10/3/2011	0.3246	28.623	174,058
2	10/4/2011	0.3429	29.855	177,266
2	10/5/2011	0.3263	31.736	193,368
2	10/6/2011	0.3228	31.616	194,987
2	10/7/2011	0.295	28.243	190,849
2	10/8/2011	0.3057	31.318	204,446
2	10/9/2011	0.3088	27.552	176,986
2	10/10/2011	0.329	32.957	199,629
2	10/11/2011	0.273	27.712	203,250
2	10/12/2011	0.2425	23.365	191,902
2	10/13/2011	0.2402	23.74	197,459
2	10/14/2011	0.2455	23.187	189,663
2	10/15/2011	0.3059	24.14	155,345
2	10/16/2011	0.2848	25.31	173,345
2	10/17/2011	0.2955	28.576	189,933
2	10/18/2011	0.2881	27.075	186,994
2	10/19/2011	0.2738	24.63	181,250
2	10/20/2011	0.2779	24.269	173,114
2	10/21/2011	0.2913	26.878	182,907
2	10/22/2011	0.3466	36.089	208,037
2	10/23/2011	0.2785	26.041	184,885
2	10/24/2011	0.2721	27.894	204,883
2	10/25/2011	0.2856	28.708	199,779
2	10/26/2011	0.2744	26.353	188,847
2	10/27/2011	0.2793	27.005	191,413
2	10/28/2011	0.2963	30.04	202,311
2	10/29/2011	0.2928	28.162	191,651
2	10/30/2011	0.2954	25.071	167,684
2	10/31/2011	0.3375	31.984	188,030
2	11/1/2011	0.3317	32.563	193,330
2	11/2/2011	0.3139	32.454	206,908
2	11/3/2011	0.2676	23.265	172,204
2	11/4/2011	0.2889	25.527	176,428
2	11/5/2011	0.289	24.936	172,793
2	11/6/2011	0.2969	25.477	171,359
2	11/7/2011	0.262	19.485	129,072
2	11/9/2011	0.1507	6.801	50,118
2	11/10/2011	0.2725	21.016	153,874
2	11/11/2011	0.2444	20.408	165,110
2	11/12/2011	0.3042	26.637	175,346
2	11/13/2011	0.3302	30.458	185,707
2	11/14/2011	0.2984	25.694	170,338

2	11/15/2011	0.2926	20.775	141,914
2	11/16/2011	0.3269	21.819	136,238
2	11/17/2011	0.3152	28.964	184,844
2	11/18/2011	0.3428	33.473	195,154
2	11/19/2011	0.3236	32.434	200,738
2	11/20/2011	0.3436	33.209	192,162
2	11/21/2011	0.3228	32.172	196,138
2	11/22/2011	0.3177	28.567	178,506
2	11/23/2011	0.3145	28.129	176,366
2	11/24/2011	0.3302	21.202	130,692
2	11/25/2011	0.2779	21.25	151,984
2	11/26/2011	0.2963	26.207	173,827
2	11/27/2011	0.3308	27.062	162,932
2	11/28/2011	0.3039	27.534	178,807
2	11/29/2011	0.2962	25.953	175,906
2	11/30/2011	0.3092	24.526	159,232
2	12/1/2011	0.3134	26.167	168,733
2	12/2/2011	0.2819	25.736	181,519
2	12/3/2011	0.3392	24.974	149,365
2	12/4/2011	0.2985	26.271	178,248
2	12/5/2011	0.2946	28.484	193,406
2	12/6/2011	0.289	25.317	179,603
2	12/7/2011	0.2953	21.698	149,209
2	12/8/2011	0.3079	19.546	132,742
2	12/9/2011	0.3015	21.19	147,856
2	12/10/2011	0.2896	26.812	186,436
2	12/11/2011	0.302	27.771	185,936
2	12/12/2011	0.285	23.779	166,663
2	12/13/2011	0.2806	18.117	129,960
2	12/14/2011	0.2838	19.14	134,316
2	12/15/2011	0.2949	23.489	157,149
2	12/16/2011	0.3114	29.531	190,167
2	12/17/2011	0.3121	25.9	165,930
2	12/18/2011	0.327	27.776	168,922
2	12/19/2011	0.3095	25.127	161,665
2	12/20/2011	0.2754	22.849	163,201
2	12/21/2011	0.3067	25.873	164,714
2	12/22/2011	0.3334	27.904	166,210
2	12/23/2011	0.3517	30.803	174,912
2	12/24/2011	0.3165	24.891	158,405
2	12/25/2011	0.3011	17.471	117,238
2	12/26/2011	0.305	25.869	168,332
2	12/27/2011	0.306	25.925	167,343
2	12/28/2011	0.3137	27.543	172,303
2	12/29/2011	0.2716	21.473	158,248
2	12/30/2011	0.2563	18.977	147,671
2	12/31/2011	0.2609	19.478	148,056

Max (tpd) -->	**42.329**
Max (lb/hr) -->	**3527.416667**

Note: Dates with no operation/emissions not shown

APPENDIX E

S&L NOX CONTROL TECHNOLOGY STUDY

Prepared for
Gill Elrod Ragon Owen & Sherman, P.A.

NOx Control Technology Cost and Performance Study

Entergy Services, Inc.
White Bluff & Lake Catherine

SL-011439
Final Report
Rev. 4

May 16, 2013
Project No.: 13027-001

Prepared by

Sargent & Lundy LLC

55 East Monroe Street
Chicago, IL 60603-5780 USA

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White Bluff & Lake Catherine
NOx Control Technology Cost and Performance Study

ISSUE SUMMARY AND APPROVAL PAGE

This is to certify that this report has been prepared, reviewed and approved in accordance with Sargent & Lundy's Standard Operating Procedure SOP-0405, which is based on ANSI/ISO/ASSQC Q9001 Quality Management Systems.

CONTRIBUTORS

Prepared by:

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ENTERGY SERVICES, INC.

WHITE BLUFF AND LAKE CATHERINE

NO_X CONTROL TECHNOLOGY COST AND PERFORMANCE STUDY

CERTIFICATION PAGE

Sargent & Lundy, L.L.C. is registered in the State of Arkansas to practice engineering.
The registration number is 620.

I certify that this study was prepared by me or under my supervision and that I am a registered professional engineer under the laws of the State of Arkansas.

Certified By: Sean C. McHone Date: 5/16/2013

Seal:

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Issue:	Date:	Certified By:	Pages Certified:

1. INTRODUCTION

1.1. OBJECTIVE

The intent of this study is to provide Gill Elrod Ragon Owen & Sherman, P.A. with a technology evaluation and cost estimates for available methods of NOx control at two Entergy stations including: White Bluff – Units 1 & 2, the White Bluff Auxiliary Boiler, and Lake Catherine – Unit 4. The information developed in this study will be used to create a BART analysis, for compliance with Arkansas DEQ regulations.

1.2. UNIT DESCRIPTIONS

1.2.1. White Bluff - Units 1 & 2

White Bluff - Units 1 & 2 are Alstom-designed, tangentially-fired, pulverized-coal fueled units, rated at 815 MWnet and 844 MWnet respectively. Powder River Basin coal is the primary fuel source for Units 1 & 2. Currently, the units have no NOx controls installed.

1.2.2. White Bluff Auxiliary Boiler

The White Bluff Auxiliary boiler is a small industrial boiler capable of producing 140,000 lb/hr of steam, used for startup of the White Bluff coal units. The auxiliary boiler combusts No. 2 Diesel Oil, and does not have any existing NOx controls.

1.2.3. Lake Catherine - Unit 4

Lake Catherine - Unit 4 is an Alstom-designed, tangentially-fired, natural gas fueled unit, capable of generating 558 MWnet. The unit was originally designed as a dual-fuel unit, able to use natural gas or No. 2 Fuel Oil as fuel. This evaluation will be for natural gas firing only. If No. 2 Fuel Oil is to be combusted in the future, a separate BART analysis will be submitted. The unit currently has no NOx controls.

1.3. ESTIMATE METHODOLOGY

1.3.1. Capital Cost Estimates

S&L's capital cost estimates for retrofit NOx control technologies for White Bluff Units 1&2, White Bluff Auxiliary Boiler and Lake Catherine – Unit 4 encompass the equipment, material, labor, and all other required direct costs. The underlying assumption is that the project will be implemented on a multiple-contracting basis. The capital cost estimates provided herein are "total plant cost," and include the following:

- Equipment and material
- Installation labor
- Indirect field costs and BOP engineering
- Contingency (percentage varies with project size)
- Erection contractor profit (at 10% of material and labor)
- General and administration (at 5% of material and labor)
- Freight on material (at 5% of material)
- Freight on equipment (included with equipment costs)
- Sales/use tax (not included)
- Startup and commissioning (at 1% of construction cost)
- Spare parts (included with equipment costs)
- Consumables (0.5% of material and labor)

Owner's engineering and other Owner's costs were not included. Engineering, Procurement & Project Services and Contingency varied depending on the size of the project. License fees and royalties are not expected for the proposed control strategies. The Basis of Estimate and capital costs are summarized in Appendix A.

Capital cost estimates were calculated in one of three ways. In some cases, vendors were contacted to provide budgetary estimates for equipment and labor. These vendor's costs were used to create Total Installed Cost Estimates. In situations where Sargent & Lundy had performed cost estimates for these units previously, the existing cost estimates were updated to reflect current equipment, labor, and currency values. Remaining cost estimates were developed from similar projects that Sargent & Lundy has completed and adjusted for unit size.

1.3.2. Operating and Maintenance Cost Estimates

Operating and Maintenance Costs for White Bluff - Units 1 & 2 and Lake Catherine – Unit 4 were developed from similar projects Sargent & Lundy has completed. Costs were applied to the units on a $/kW basis, and assuming a 10% capacity factor for Lake Catherine – Unit 4, and 76% for White Bluff—Units 1 & 2. Operating and Maintenance Costs include the following costs:

- Fixed Operating and Maintenance
- Variable Operating and Maintenance
- Fuel Impact Costs

For the White Bluff Auxiliary boiler, costs were developed using Office of Air Quality Planning and Standards (OAQPS) calculations, assuming a 10% capacity factor.

1.4. DESIGN TARGET vs. COMPLIANCE NO_X EMISSION RATES

NOx control systems retrofit onto existing coal or gas-fired boilers are typically designed to achieve varying levels of NOx removal efficiencies from 10%-94%, depending on the control technologies selected. Controlled NOx emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NOx concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures, flue gas velocities and mixing, catalyst volume and surface area, NH_3:NOx stoichiometric ratio, catalyst age and activity, and the quantity of ammonia slip deemed to be acceptable.

The “design target” NOx emission rate is the rate that a NOx control technology vendor would be willing to guarantee. Based on engineering judgment, and taking into consideration emissions data from existing coal- and gas-fired sources, a compliance margin above the design target is recommended for high removal efficiency/low emission rate technologies (such as SCR) to establish an enforceable permit limit based on long-term (e.g., annual average) emissions. Additional compliance margin would be required to establish enforceable permit limits based on shorter-term averaging times. For example, S&L recommends a compliance margin of 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units above the design target emission rate for permit limits based on a 30-day rolling average for control strategies including SCR. The NOx control technology emission rates for strategies including SCR in this report have been adjusted to include margin for compliance. The permit level NOx emission rates for SCR are higher by 0.02 to 0.03 lb/MMBtu for coal units and 0.01 to 0.02 lb/MMBtu for gas units.

2. WHITE BLUFF - UNITS 1 & 2

2.1. FUEL SWITCHING OPTIONS

2.1.1. Natural Gas

For White Bluff Units 1 & 2, fuel switching is not a feasible option. Typically, units could be switched from coal to natural gas or propane for NOx reductions. The nearest natural gas pipeline to the White Bluff facility is approximately 20 miles away. Construction of a pipeline is currently estimated at $2M per mile resulting in a cost of $40M to bring natural gas to the site, not including the additional upgrades the boiler would require to burn natural gas instead of coal.

2.1.2. Propane

White Bluff – Units 1 & 2 are each over 800 MWnet. Units of this size require more heat input than can practically be achieved with a propane delivery and storage system. Since a propane pipeline is not available, fuel switching to propane is not a feasible option.

2.2. COMBUSTION CONTROLS

2.2.1. Low NOx Burners and Over-Fire Air

Low NOx burners (LNB) limit NOx formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. Control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced flame temperature, and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NOx emissions during the combustion process.

OFA involves injecting combustion air downstream of the fuel-rich primary combustion zone by using over-fire air or side-fired air ports. The fuel-rich mixture that is fed to the burners reduces the flame temperature and oxygen concentration thus reducing the formation of thermal NOx. Generally, OFA is more effective when used with low nitrogen content fuels such as natural gas and propane, since OFA is more effective in controlling thermal NOx rather than fuel NOx.

LNB + OFA is a technically feasible retrofit solution for White Bluff - Units 1 & 2. The combination of LNB + OFA is capable of achieving a NOx emission rate of 0.15 lb/MMBtu. From Unit 1's baseline emissions of 0.33 lb/MMBtu, this is approximately 54.5% NOx removal efficiency. A removal efficiency of 61.5% can be expected for Unit 2, with a baseline NOx of 0.39 lb/MMBtu.

2.2.2. Flue Gas Recirculation (FGR)

NOx reduction efficiency data for coal-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. Industry experience with FGR on coal-fired units for steam temperature control has shown very high maintenance on the gas recirculation fans due to erosion and corrosion. Many of the units with FGR for steam temperature control have removed the recirculation fans from service. The NOx control achievable on tangentially fired units like White Bluff – Units 1&2 with LNB+OFA has been comparable to that of FGR at lower capital and O&M cost. Currently, FGR technology is not offered by OEMs for coal-fired units. For these reasons, FGR is not a feasible technology for the White Bluff coal-fired units.

2.2.3. Neural Network

Neural Network (NN) systems are on-line enhancements to digital control systems (DCS) and plant information systems that improve boiler performance parameters such as heat rate, NOx emissions, and CO levels. The Neural Network model is based on historical data and parametric test data. The software applies an optimizing procedure to identify the best set points for the boiler, which are implemented without operator intervention (closed loop), or, at the plant's discretion, conveyed to the plant operators for implementation (open loop).

A Neural Network system is a technically feasible retrofit option for the White Bluff units. A NN is already installed for monitoring and controlling heat rate at White Bluff – Units 1&2. The reprogrammed

NN would be optimized first for minimizing NOx emissions and second for heat rate. It is possible that heat rate may increase as a result. Based on information available from vendors, it is expected that Neural Network technology on a coal-fired boiler can maintain the guaranteed performance of low NOx burners and potentially can achieve approximately 10% NOx reduction over a period of years, resulting in NOx emission rates of 0.30 lb/MMBtu, at max load for Unit 1, and of 0.35 lb/MMBtu for Unit 2. The cost for modifying the existing NNs at White Bluff is estimated to be approximately $250,000 per unit.

2.3. POST COMBUSTION CONTROLS

2.3.1. Selective Non-Catalytic Reduction

Selective non-catalytic reduction (SNCR) involves the direct injection of ammonia (NH_3) or urea ($(CO(NH_2)_2)$) into the furnace at high flue gas temperatures (approximately 1600 ºF – 2000 ºF). The ammonia or urea reacts with NOx in the flue gas to produce N_2 and water as shown in the following equations:

$$(CO(NH_2)_2) + 2NO + \frac{1}{2}O_2 \rightarrow 2H_2O + CO_2 + 2N_2$$

$$2NH_3 + 2NO + \frac{1}{2}O_2 \rightarrow 2N_2 + 3H_2O$$

Flue gas temperature at the point of reactant injection can greatly affect NOx removal efficiencies and the quantity of NH_3 or urea that will pass through the furnace unreacted (referred to as NH_3 slip). In general, SNCR reactions are effective at a temperature range of 1600 ºF – 2000 ºF. At temperatures below the desired operating range, the NOx reduction reactions diminish and unreacted NH_3 emissions increase. Above the desired temperature range, NH_3 is oxidized to NOx resulting in low NOx reduction efficiencies.

Mixing of the reactant and flue gas within the reaction zone is also an important factor to SNCR performance. In large boilers, the physical distance over which reagent must be dispersed increases, and the surface area/volume ratio of the convective pass decreases. Both of these factors make it difficult to achieve good mixing of reagent and flue gas, delivery of reagent in the proper temperature window, and sufficient residence time of the reactant and flue gas in that temperature window.

The temperatures and residence times required for an SNCR system make it a feasible option for NOx reduction for White Bluff - Units 1 & 2. Based on vendor input, a unit with no additional controls and a baseline NOx of 0.33 lb/MMBtu could see a 26.5% NOx reduction, for an outlet rate of 0.24 lb/MMBtu on Unit 1. For Unit 2, with a baseline NOx of 0.39 lb/MMBtu could see a 26.5% reduction to an outlet rate of 0.29 lb/MMBtu.

SNCR systems can also be installed in conjunction with LNB + OFA controls. On these coupled systems, the starting NOx of approximately 0.15 lb/MMBtu can be reduced to 0.13 lb/MMBtu, for a total reduction (LNB + OFA + SNCR) of around 61% for Unit 1 and 67% for Unit 2. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 170 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost. The cost of the SNCR equipment for the combination technology would be approximately 10% lower based on the lower starting NOx rate with LNB/OFA.

2.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) involves injecting ammonia into boiler flue gas in the presence of a catalyst to reduce NOx to N_2 and water. The overall SCR reactions are:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$8NH_3 + 4NO_2 + 2O_2 \rightarrow 6N_2 + 12H_2O$$

The optimal temperature range depends on the type of catalyst used, but is typically between 560 °F and 800 °F to maximize NOx reduction efficiency and minimize ammonium sulfate formation. Below this range, ammonium sulfate is formed resulting in catalyst deactivation. Above the optimum temperature, the catalyst will sinter and thus deactivate rapidly. Another factor affecting SCR performance is the condition of the catalyst material. As the catalyst degrades over time or is damaged, NOx removal decreases which is typically compensated by increased ammonia slip.

SCR has been installed on many large coal-fired and some gas-fired boilers and is considered a feasible technology. Because of the expense of the reagent, SCR systems are usually installed on units with existing LNB + OFA systems, or the upgrades are done simultaneously. At White Bluff, an SCR+LNB/OFA system is capable of removing approximately 90% of NOx emissions on a continuous long-term basis. With a starting NOx of 0.33 lb/MMBtu (Unit 1) to 0.39 lb/MMBtu (Unit 2), an SCR can be expected to achieve permitted emissions compliance at 0.055 lb/MMBtu.

2.4. CAPITAL COSTS

Capital costs for the technically feasible control options for the White Bluff coal units are listed in Table 2.1. The cost of SCR on White Bluff – Unit 1 is higher than for White Bluff – Unit 2 because the ductwork arrangement is different and there is more total ductwork, support steel, and foundations for Unit 1.

Table 2.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	**Controlled NOx (lb/MMBTU)**		**Unit 1 Total Installed Capital Cost (2012$)**	**Unit 2 Total Installed Capital Cost (2012$)**
	Unit 1	Unit 2		
Baseline	0.33	0.39	NA	NA
LNB + OFA	0.15	0.15	7,804,000[1]	11,831,000
Neural Network	0.30	0.35	250,000[2]	250,000[2]
SNCR	0.24	0.29	9,372,000	9,372,000
SNCR (+ LNB/OFA)	0.13	0.13	16,290,000[1]	20,317,000
SCR (+ LNB/OFA)	0.055	0.055	202,601,000	178,240,000

1. LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
2. The cost for modifying the existing neural networks on Units 1 & 2.

2.5. OPERATING AND MAINTENANCE COSTS

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 2.2. Costs were calculated assuming full load operation, and a capacity factor (C.F.) of 76%.

Table 2.2: Operating and Maintenance Costs, White Bluff – Units 1 & 2 (Based on a C.F. of 76%)

	Unit 1			Unit 2		
Technology	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**	**Variable O&M[1] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**
LNB + OFA	--	142,000	142,000	--	142,000	142,000
Neural Network	--	50,000	50,000	--	50,000	50,000
SNCR	5,658,000	169,000	5,827,000	6,671,000	169,000	6,840,000
SNCR (+ LNB/OFA)	4,538,000	311,000	4,849,000	4,542,000	311,000	4,853,000
SCR (+ LNB/OFA)	2,836,000	608,000	3,444,000	2,858,000	608,000	3,466,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

3. WHITE BLUFF AUXILIARY BOILER

3.1. FUEL SWITCHING

The White Bluff auxiliary boiler is a B&W, single burner boiler, firing No. 2 diesel oil, rated at 140,000 lb/hr of steam. Fuel switching to natural gas or propane is not practical because the nearest natural gas pipeline is 20 miles from the site. The costs to convert the White Bluff aux boiler to either natural gas or propane would not be justified based on the low capacity factor.

3.2. COMBUSTION CONTROLS

3.2.1. Low NOx Burners + Over-Fire Air

For an auxiliary boiler such as the one at White Bluff, NOx reduction can be achieved with a combination of technologies. LNB + OFA for aux boilers achieve NOx reduction under the same principles as a coal boiler. By modifying temperatures and fuel-rich areas, less NOx is generated. LNB + OFA are feasible technologies for auxiliary boilers, and vendor data indicates that the White Bluff Aux Boiler could achieve 35% reduction with LNB + OFA, for a final emission of 0.11 lb/MMBtu. The baseline NOx emissions from the White Bluff aux boiler are calculated using US EPA's AP-42 emissions factors.

3.2.2. Flue Gas Recirculation

NOx reduction efficiency data for oil-fired units with FGR are limited. The amount of NOx reduction achievable with FGR depends primarily on the fuel nitrogen content and amount of FGR used. Generally, FGR is more effective when used with low nitrogen content fuels such as natural gas and propane, since FGR is more effective in controlling thermal NOx rather than fuel NOx. FGR is a feasible technology for the White Bluff auxiliary boiler. With a recirculation of 15% of the flue gas, the unit could expect to see 13% NOx removal, for an outlet of 0.149 lb/MMBtu.

3.2.3. Low NOx Burners + Over-fire Air + Flue Gas Recirculation

These three technologies are often installed simultaneously for greater NOx reduction. A vendor has proposed that for the White Bluff aux boiler, a combination of LNB + OFA + FGR will reduce the NOx from 0.171 lb/MMBtu to 0.100 lb/MMBtu when burning No. 2 Fuel Oil. This reduction of 42% will come from a new LNB and OFA system and the recirculation of 15% of the flue gas flow.

3.2.4. Neural Network

The White Bluff Auxiliary Boiler is not a candidate for a neural network (NN) because there are few controllable variables to be optimized. The aux boiler also uses a relatively new PLC control system.

3.3. POST COMBUSTION CONTROLS

3.3.1. Selective Non-Catalytic Reduction

SNCR control has proven to be difficult to apply to industrial boilers because of the temperature and mixing requirements, especially industrial boilers that modulate or cycle frequently. In order to effectively reduce NOx emissions, the reactant (ammonia or urea) must be injected into the flue gas within a specific flue gas temperature window, and must remain within that temperature window for a sufficient residence time. In industrial boilers that cycle frequently, the location of the specific exhaust gas temperature window is constantly changing. Thus, SNCR has not been effective on industrial boilers that have high turndown capabilities and modulate or cycle frequently. Based on the temperature and residence time requirements associated with effective NOx reduction, the planned use of the auxiliary boiler, and the limited availability of SNCR control systems for industrial boilers, it has been determined that SNCR is not technically feasible for the White Bluff auxiliary boiler.

3.3.2. Selective Catalytic Reduction

SCR for NOx control on auxiliary boilers is not common, because of their cycling operation, and the use of fuel oil. SCRs have critical operating temperature ranges, which are difficult to achieve and maintain in short periods of time. Because of the sulfur content of diesel oil, the SCR catalyst can become poisoned, resulting in a lower NOx removal efficiency. With this lower efficiency and high cost, an SCR is not considered a feasible technology.

3.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for the White Bluff Auxiliary Boiler are listed in Table 3.1.

Table 3.1: Expected NOx Emissions and Capital Costs, White Bluff Units 1 & 2

Technology	Controlled NOx	Total Installed Capital Cost (2012$)
Baseline	0.171	--
LNB	0.111	255,000
OFA	0.137	231,000
FGR	0.149	366,000
LNB + OFA + FGR	0.100	852,000

3.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for White Bluff Units 1 & 2 are shown in Table 3.2. Costs were calculated assuming full load operation and a capacity factor (C.F.) of 10%.

Table 3.2: White Bluff Auxiliary Boiler Operating and Maintenance Costs (Based on a C.F. of 10%)

Technology	Variable O&M Costs (2012$)	Fixed O&M Costs (2012$)	Total O&M Costs (2012$)
LNB	4,000	4,000	8,000
OFA	5,000	4,000	9,000
FGR	0	7,000	7,000
LNB + OFA + FGR	9,000	15,000	24,000

4. LAKE CATHERINE - UNIT 4

4.1. FUEL SWITCHING

Lake Catherine - Unit 4 already combusts natural gas, which has the lowest NOx formation of potential fuels. Because fuel switching would not result in a lower NOx emission rate, it is not a feasible option for NOx control.

4.2. COMBUSTION CONTROLS

4.2.1. Burners-Out-Of-Service

Burners-Out-Of-Service (BOOS) allows operators to stop fuel flow to certain burners in the boiler (typically the top level of burners), while air flow is maintained. By removing fuel from the top row of burners, the combustion air becomes over-fire air and the production of thermal NOx is reduced. While the reduction of NOx can be significant, the tradeoff is a reduced generating capacity, if no further modifications to the firing system are made. BOOS is a feasible technology for Lake Catherine - Unit 4. Testing of BOOS at Lake Catherine by Entropy Technology & Environmental Consultants, Inc. (ETEC) with the top levels of burners out resulted in a maximum load of 405 MW, a 28% reduction in capacity, and NOx levels of 0.12 lb/MMBtu, a reduction of 55% from the baseline while using the existing burners.

Recovery of the lost unit capacity is possible by increasing the fuel fired in the three levels of burners that remain in service. The burners remaining in service would have to increase fuel throughput by 25%. The natural gas piping to each burner may also have to be increased in size for the higher fuel flow rates. ETEC, Inc. has experience with several units similar in design to Lake Catherine – Unit 4 that have been able to achieve full capacity by increasing the original “high” burner header pressure (BHP) to increase fuel flow to the burners (See Appendix D). The increase in BHP from 42 to 50 psig at Lake Catherine – Unit 4 would increase fuel flow by 25% and the burners would be operated “fuel rich”, lowering NOx formation. Using this approach would reduce NOx emissions at a small capital cost. The costs for BOOS with recovery of full unit capacity were based on vendor cost information for a previous project adjusted on a $/kW basis to Lake Catherine – Unit 4 and escalated to 2012. The cost provided does not include any modifications to the boiler. A boiler OEM or consultant would need to evaluate the existing fuel piping, superheat and reheat attemperation sprays, tube metal temperatures and burner tilt positions for the new operating conditions. The expected NOx reduction would range from 40% at low load to 50% at full load and NOx levels of 0.24 lb/MMBtu.

4.2.2. Low NOx Burners + Over-Fire Air

Low NOx Burners and Over-Fire Air for a gas-fired unit function similarly to coal-fired boilers, as discussed for White Bluff - Units 1 & 2. By controlling the temperature and stoichiometric profiles, the NOx produced as a result of thermal processes is reduced.

LNB + OFA are commonly installed on gas-fired units of this size, and are a feasible retrofit technology for Lake Catherine - Unit 4. With the installation of LNB + OFA, Lake Catherine could expect a 60% reduction in NOx, from 0.4825 lb/MMBtu to 0.19 lb/MMBtu.

4.2.3. Flue Gas Recirculation

Flue Gas Recirculation (FGR) reduces NOx by recirculating flue gas to the furnace. This recirculated gas has lower oxygen content than ambient air usually used for combustion. Lower oxygen and lower flame temperatures reduces thermal NOx formation. FGR can be installed on a unit in two ways. Traditional FGR installations require a new recirculation fan. Induced FGR, or IFGR, installs ductwork from the air preheater outlet to the suction of the existing forced draft fan. IFGR does not require a separate fan, but due to FD fan capacity restrictions, IFGR is not available at higher loads, because the forced draft fans were not designed for the higher air and gas flow rate.

FGR is technically feasible on Lake Catherine - Unit 4 and can result in reductions of 60%. For Unit 4, this would be equivalent to NOx emissions of 0.19 lb/MMBtu.

4.2.4. Water Injection

Water injection operates on similar principles to LNB + OFA and FGR. By injecting water into the furnace, the temperature of the flue gas is reduced, thereby reducing the amount of thermal NOx formed.

Water injection is a feasible technology for Lake Catherine - Unit 4, and can reduce NOx emissions by 9% at full load. Water injection is typically used as a trimming technology at high load. On Unit 4, the emissions would be lowered from the baseline of 0.4825 lb/MMBtu to 0.44 lb/MMBtu.

4.2.5. Neural Network

Lake Catherine – Unit 4 could also install a neural network (NN) but for the low capacity factor and current lack of NOx CEMS, a NN would not be practical. Several of the other technologies would provide greater NOx reductions.

4.3. POST COMBUSTION CONTROLS

4.3.1. Selective Non-Catalytic Reduction

Selective Non-Catalytic Reduction for gas-fired units operates under the same principles as SNCR for coal-fired units, with a few design changes. One of the keys of SNCR design is adequate chemical distribution at the right temperature for the reaction. Lake Catherine - Unit 4 has horizontal superheat platens, which requires multiple-nozzle lances to distribute the urea; the gas pattern does not provide adequate distribution. The reaction and temperature requirements are the same for gas-fired boilers as they are for coal-fired units.

SNCR has been installed on boilers such as Lake Catherine 4 and is considered a feasible technology, although the residence time in the desired temperature zone is lower for a gas-fired unit and the temperature window moves as unit load changes. The unit could expect to see reductions in NOx from the baseline of 0.4825 lb/MMBtu to 0.29 lb/MMBtu, or approximately 40% reduction at full load. In addition to the SNCR equipment, the process requires additional demineralized water at a rate of 85 gpm. An additional water treatment system capable of providing the required flows is included in the capital cost.

SNCR can be combined with LNB/OFA to achieve a combined NOx removal efficiency of 70% for an outlet emission of approximately 0.14 lb/MMBtu,

4.3.2. Selective Catalytic Reduction

Selective Catalytic Reduction units are similar for gas and coal-fired units. Ammonia or urea reagent reacts with NOx to form nitrogen and water, in the presence of a catalyst. Because gas boilers do not have particulate control or sulfur dioxide control, they typically have a shorter distance from the economizer outlet to the stack, which may result in long ductwork runs to and from the SCR.

SCR is a feasible technology for Lake Catherine - Unit 4. Combined with a LNB + OFA installation, which is typical of SCR installations, the unit could achieve a combined NOx removal efficiency of 94%, for a permitted outlet NOx of 0.03 lb/MMBtu at full load. This includes a margin for compliance as discussed in Section 1.4. Without the LNB + OFA installed, the SCR can also be designed to achieve 90% removal efficiency for an outlet emission of approximately 0.05 lb/MMBtu.

4.4. CAPITAL COST ESTIMATES

Capital costs for the technically feasible control options for Lake Catherine - Unit 4 are listed in Table 4.1.

Table 4.1: Expected NOx Emissions and Capital Costs, Lake Catherine Unit 4

Technology	**Controlled NOx (lb/MMBtu)**	**Total Installed Capital Cost (2012$)**
Baseline	0.4825[1]	--
BOOS (at full capacity)	0.24	893,000
LNB / OFA	0.19	8,762,000
IFGR (below 500 MW)	0.39	2,166,000
FGR	0.19	11,489,000
Water Injection	0.44	2,177,000
SNCR	0.29	15,507,000
SNCR (+ LNB/OFA)	0.14	24,269,000
SCR	0.05	59,587,000
SCR (+ LNB/OFA)	0.03	68,349,000

Note 1: The baseline NOx rate is the maximum daily emission rate from the 2001-2003 baseline period.

4.5. OPERATING AND MAINTENANCE COST ESTIMATES

Annual Operating and Maintenance costs for each of the feasible technologies for Lake Catherine - Unit 4 are shown in Table 4.2. Costs were calculated assuming full load operation, and a capacity factor (C.F. of 10%).

Table 4.2: Annual Operating and Maintenance Costs, Lake Catherine Unit 4 (Based on C.F. of 10%)

Technology	**Variable O&M[1,2] Costs (2012$)**	**Fixed O&M Costs (2012$)**	**Total O&M Costs (2012$)**
BOOS	--	21,000	21,000
LNB + OFA	--	210,000	210,000
IFGR	--	52,000	52,000
FGR	142,000	207,000	349,000
Water Injection	486,000	52,000	538,000
SNCR	1,640,000	279,000	1,919,000
SNCR (+ LNB/OFA)	462,000	489,000	951,000
SCR	254,000	358,000	612,000
SCR (+ LNB/OFA)	268,000	568,000	836,000

Note 1: Variable O&M includes fuel cost impacts.

Note 2: The current costs of ammonia and urea are highly volatile and may exceed the values used in this report.

APPENDIX A: CAPITAL COST ESTIMATE

1. BASIS OF ESTIMATES

2. CONCEPTUAL COST ESTIMATE SUMMARY SHEETS

Basis of Estimate

Estimates:
31813A – Lake Catherine, Unit 4 - Low NOx Burners and Over Fired Air
31814A – Lake Catherine, Unit 4 - SCR
31815A – Lake Catherine, Unit 4 - SNCR
31816A – White Bluff, Unit 1 - Low NOx Burners and Over Fired Air
31817A – White Bluff, Unit 1 – SCR
31818A – White Bluff, Unit 2 – SCR
31819A – White Bluff, Units 1 and 2 – SNCR
31820A – White Bluff, Auxiliary Boiler – Low NOx Burners, Over Fired Air, and Flue Gas Recirculation
31832A – White Bluff, Unit 2 - Low NOx Burners and Over Fired Air

General Information

Project Type – Compliance study for Lake Catherine Unit 4 and White Bluff Station Units 1&2.
Type of estimates – Conceptual Cost Estimate for the SCR Case and Order of Magnitude Cost Estimates for all other cases.
Project location – White Bluff: Close to Pine Bluff, Arkansas; Lake Catherine: Close to Mahern, AR
MW rating: White Bluff Unit 1: 815 MW, Unit 2: 844 MW; Lake Catherine Unit 4: 558 MW
Unique site issues – Existing Site.
Contracting strategy – Multiple Lump Sum.

The major components of the capital cost consist of equipment, field materials and supplies, direct labor, indirect field labor, and indirect construction costs. The capital cost was determined through the process of estimating the cost of equipment, components and bulk quantity.

The cost estimates are based largely on Sargent & Lundy LLC experience on similar projects. Detailed engineering has not been performed to firm up the project details, and specific site characteristics have not been fully analyzed. We have attempted to assign allowances where necessary to cover issues that are likely to arise but are not clearly quantified at this time.

Estimate Development

The cost estimates for the Low NOx Burners/Over Fired Air cases were based on a previous estimate prepared in 2011. Equipment costs were escalated to current pricing level. Also, material and labor have been updated to 2012 pricing.
Cost estimates for the SNCR technology (two cases) were based on budgetary quotes received from engineering and on previous estimates.
The cost estimates for the White Bluff SCR was mainly based on similar size and scope cost estimates from other projects and structural takeoffs from engineering. All equipment common to both Units was divided evenly between the two estimates.
The cost estimate for Lake Catherine SCR was adjusted from another cost estimate for a gas fired power station. White Bluff's auxiliary boiler cost estimate for Low NOx Burners/Over Fired Air/Flue Gas Recirculation was also adjusted from a similar project.

Pricing and Quantities

The data used to develop these estimates is based on using material and equipment types and sizes typically used in a power plant.
Equipment and material costs were estimated on the basis of S&L in house data, vendor catalogs, industry publications and other related projects. In most cases, the costs for bulk materials and equipment were derived from recent vendor or manufacturer's quote for similar items on other projects. Where actual or specific information regarding equipment specifications was available, that information was used to size and quantify material and equipment requirements. Where information was not furnished or was not adequate, requirements were assumed and estimated based on information available from project estimates of similar type and size.

Quantities contained herein are intended to be reasonable and representative of projects of this type. All quantity data was developed internally by S&L. Quantities were developed based on project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement drawing. While project specifics will certainly have an impact on these quantities, we feel they are appropriate for a study at this level.

Labor Wage Rates

Labor Profile – Union

Labor wage rate selected for the estimate - 2012 Union rates for Pine Bluff, Arkansas. Base craft rates are as published in RS Means Labor Rates for the Construction Industry, 2012 Edition. The craft rates are then incorporated into work crews appropriate for the activities by adding allowances for small tools, construction equipment, insurance, and site overheads to arrive at crew rates detailed in the cost estimate. A 1.15 regional labor productivity multiplier is included based on the Compass International Global Construction Yearbook.

Labor Work Schedule and Incentives - Assumed 5x10 work week for regular work and 7x10 work week for outage work. 10% of the work is assumed to be outage related.

Project Direct & Construction Indirect Costs

The estimate is constructed in such a manner where most of the direct construction costs are determined directly and several direct construction cost accounts are determined indirectly by taking a percentage of the directly determined costs and are identified as "Variable Accounts". These percentages are based on our experience with similar type and size projects. Sales tax is specific to location. Listed below are the variable accounts.

- Cost of overtime – 5-10's Hour Days and Outage Work at a 7-10 Schedule
- Subsistence (per diem) – not included
- Consumables – 0.5% of material and labor
- Freight on Equipment - included with equipment cost
- Freight on Material @ 5% of material
- Spare Parts – included with equipment costs
- Contractors G&A Expense @ 10%
- Contractors Profit @ 5%

Project Indirect Costs

Included are the following:

- Engineering, Procurement & Project Services varied depending on the size of the project estimated.
  - 31813A @ 19% of construction cost
  - 31814A @ 8% of construction cost
  - 31815A @ 8% of construction cost
  - 31816A @ 16% of construction cost
  - 31817A @ 6% of construction cost
  - 31818A @ 6% of construction cost
  - 31819A @ 8% of construction cost
  - 31820A @ 12% of construction cost
  - 31832A @ 16% of construction cost
- Construction Management varied depending on the size of the project estimated.
  - 31813A @ 6% of construction cost
  - 31814A @ 3% of construction cost
  - 31815A @ 2% of construction cost
  - 31816A @ 6% of construction cost
  - 31817A @ 2% of construction cost

  - 31818A @ 2% of construction cost
  - 31819A @ 2% of construction cost
  - 31820A @ 0% of construction cost
  - 31832A @ 6% of construction cost
- Craft start-up and commission support @ 1% of construction cost
- General Owner's Costs, including Owners Engineering & Bond Fees – not included
- EPC Fee – not included

These percentages are based on our experience with similar type and size projects.

Escalation

Not included.

Contingency

The contingency rates vary for each project based on the project's size. The rates are based on past history of similar projects. This rate relates to pricing and quantity variation in the specific scope estimated. The contingency does not cover new scope outside of what has been estimated, only the variation in the defined scope. This is a composite rate and already takes into account the plus and minuses of expected actual costs. The rate does not represent the high range of all costs, nor is it expected that the project will experience all actual costs be realized at the maximum value of their range of variation.

Exclusions

There are items that have been specifically excluded from the estimate. In order to establish the overall project costs, the following items must also be accounted for. This list is for information only and is not intended to be all inclusive.

- Permitting costs
- Rock excavation
- Remediation of soil for hazardous materials
- Power outage cost during construction

Assumptions

- No rock excavation, no dewatering
- Assumed that asbestos removal or lead paint abatement will not be required.
- No obstruction for the ammonia pipe routing. 6" clearing & grubbing of existing terrain is included, no tree removal.
- Directional boring underneath the existing railroad tracks is included, but with no major interferences or obstructions.
- Electrical equipment and wiring installation is based on non-hazardous location.
- Adjustments for plant unit size were made based on good engineering practice. Actual design and quantities may be significantly different than the quantities shown in the estimates.

Estimate Totals

Description	Amount	Totals	
Labor	331,677		
Material	125,263		
Subcontract	2,850,000		
Equipment			
Other	2,000,000		
	5,306,940	5,306,940	USD
91-1 Scaffolding	46,000		
91-2 OT Working 5-10 Hour Days	41,000		
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables	2,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	6,000		
91-9 Freight on Process Equip.	100,000		
91-10 Sales Tax			
91-11 Contractor's G&A Expense	65,000		
91-12 Contractor's Profit	32,000		
	292,000	5,598,940	USD
93-1 EP&P Services	1,064,000		
93-2 CM Support	168,000		
93-3 Start-Up/Commissioning	56,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,288,000	6,886,940	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	50,000		
94-4 Contingency on Labor	145,000		
94-5 Contingency on Sub.	713,000		
94-6 Contingency on Equipment	525,000		
94-7 Contingency on Indirect	386,000		
	1,819,000	8,705,940	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		8,705,940	USD
98 - Interest During Constr			
		8,705,940	USD
Total		8,705,940	USD

Estimate Totals

Description	Amount	Totals	
Labor	19,780,000		
Material	15,815,652		
Subcontract	2,590,000		
Equipment			
Other	8,290,000		
	46,475,652	46,475,652	USD
91-1 Scaffolding			
91-2 OT Working 5-10 Hour Days			
91-3 OT Working 7-10 Hr Days			
91-4 Per Diem			
91-5 Consumables			
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material			
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense			
91-12 Contractor's Profit			
		46,475,652	USD
93-1 EP&P Services	3,718,100		
93-2 CM Support	1,394,300		
93-3 Start-Up/Commissioning	464,800		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	5,577,200	52,052,852	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	2,372,400		
94-4 Contingency on Labor	2,967,000		
94-5 Contingency on Sub.	388,500		
94-6 Contingency on Equipment	1,243,500		
94-7 Contingency on Indirect	836,600		
	7,808,000	59,860,852	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		59,860,852	USD
98 - Interest During Constr			
		59,860,852	USD
Total		59,860,852	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,629,958		
Material	1,083,165		
Subcontract	80,600		
Equipment			
Other	6,193,056		
	9,986,779	9,986,779	USD
91-1 Scaffolding	445,600		
91-2 OT Working 5-10 Hour Days	311,700		
91-3 OT Working 7-10 Hr Days	99,200		
91-4 Per Diem			
91-5 Consumables	18,600		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,200		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	458,800		
91-12 Contractor's Profit	229,500		
	1,617,600	11,604,379	USD
93-1 EP&P Services	928,400		
93-2 CM Support	232,100		
93-3 Start-Up/Commissioning	116,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,276,500	12,880,879	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	390,000		
94-4 Contingency on Labor	1,209,300		
94-5 Contingency on Sub.	24,200		
94-6 Contingency on Equipment	619,300		
94-7 Contingency on Indirect	383,000		
	2,625,800	15,506,679	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		15,506,679	USD
98 - Interest During Constr			
		15,506,679	USD
Total		15,506,679	USD

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other			
	4,659,995	4,659,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	4,995,995	USD
93-1 EP&P Services	799,000		
93-2 CM Support	300,000		
93-3 Start-Up/Commissioning	50,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,149,000	6,144,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment			
94-7 Contingency on Indirect	345,000		
	1,659,000	7,803,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		7,803,995	USD
98 - Interest During Constr			
		7,803,995	USD
Total		7,803,995	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

Estimate Totals

Description	Amount	Totals	
Labor	56,778,212		
Material	34,013,262		
Subcontract	8,156,000		
Equipment			
Other	21,324,260		
	120,271,734	120,271,734	USD
91-1 Scaffolding	2,270,000		
91-2 OT Working 5-10 Hour Days	6,730,000		
91-3 OT Working 7-10 Hr Days	2,142,000		
91-4 Per Diem			
91-5 Consumables	454,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,701,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	10,238,000		
91-12 Contractor's Profit	5,120,000		
	28,655,000	148,926,734	USD
93-1 EP&P Services	8,936,000		
93-2 CM Support	2,979,000		
93-3 Start-Up/Commissioning	1,489,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	13,404,000	162,330,734	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	8,163,000		
94-4 Contingency on Labor	15,726,000		
94-5 Contingency on Sub.	1,631,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,681,000		
	32,466,000	194,796,734	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		194,796,734	USD
98 - Interest During Constr			
		194,796,734	USD
Total		194,796,734	USD

Estimate Totals

Description	Amount	Totals	
Labor	653,648		
Material	306,347		
Subcontract	3,700,000		
Equipment			
Other	2,600,000		
	7,259,995	7,259,995	USD
91-1 Scaffolding	48,000		
91-2 OT Working 5-10 Hour Days	77,000		
91-3 OT Working 7-10 Hr Days	24,000		
91-4 Per Diem			
91-5 Consumables	5,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	15,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	112,000		
91-12 Contractor's Profit	55,000		
	336,000	7,595,995	USD
93-1 EP&P Services	1,215,000		
93-2 CM Support	456,000		
93-3 Start-Up/Commissioning	76,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	1,747,000	9,342,995	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	110,000		
94-4 Contingency on Labor	279,000		
94-5 Contingency on Sub.	925,000		
94-6 Contingency on Equipment	650,000		
94-7 Contingency on Indirect	524,000		
	2,488,000	11,830,995	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		11,830,995	USD
98 - Interest During Constr			
		11,830,995	USD
Total		11,830,995	USD

Estimate Totals

Description	Amount	Totals	
Labor	2,255,791		
Material	1,089,242		
Subcontract	68,100		
Equipment			
Other	1,948,100		
	5,361,233	5,361,233	USD
91-1 Scaffolding	368,000		
91-2 OT Working 5-10 Hour Days	267,300		
91-3 OT Working 7-10 Hr Days	85,100		
91-4 Per Diem			
91-5 Consumables	16,700		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	54,500		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	408,200		
91-12 Contractor's Profit	204,100		
	1,403,900	6,765,133	USD
93-1 EP&P Services	541,200		
93-2 CM Support	135,300		
93-3 Start-Up/Commissioning	67,700		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	744,200	7,509,333	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	392,100		
94-4 Contingency on Labor	1,032,500		
94-5 Contingency on Sub.	20,400		
94-6 Contingency on Equipment	194,800		
94-7 Contingency on Indirect	223,300		
	1,863,100	9,372,433	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		9,372,433	USD
98 - Interest During Constr			
		9,372,433	USD
Total		9,372,433	USD

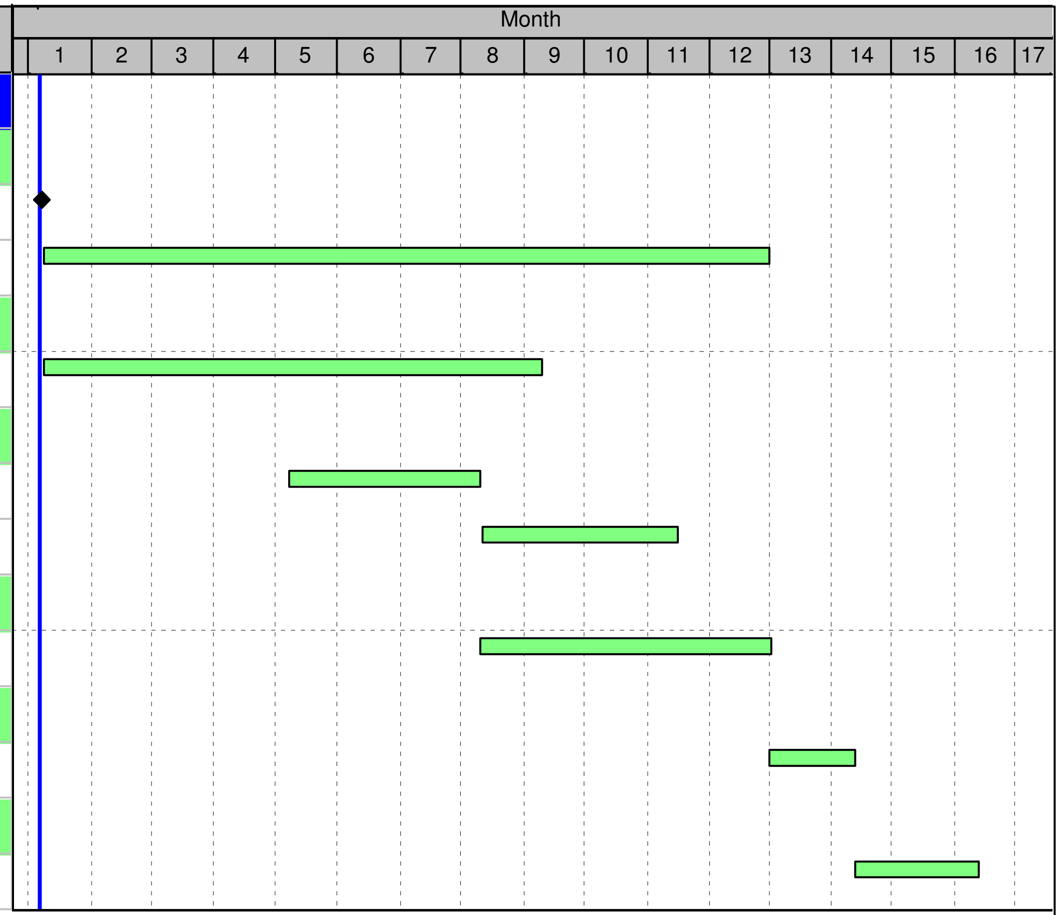
Estimate Totals

Description	Amount	Totals	
Labor	48,597,255		
Material	26,751,692		
Subcontract	6,577,640		
Equipment			
Other	21,324,260		
	103,250,847	103,250,847	USD
91-1 Scaffolding	1,884,000		
91-2 OT Working 5-10 Hour Days	5,759,000		
91-3 OT Working 7-10 Hr Days	1,834,000		
91-4 Per Diem			
91-5 Consumables	377,000		
91-6 Freight on Equipment			
91-7 Freight on Special Equip.			
91-8 Freight on Material	1,338,000		
91-9 Freight on Process Equip.			
91-10 Sales Tax			
91-11 Contractor's G&A Expense	8,520,000		
91-12 Contractor's Profit	4,261,000		
	23,973,000	127,223,847	USD
93-1 EP&P Services	7,633,000		
93-2 CM Support	2,544,000		
93-3 Start-Up/Commissioning	1,272,000		
93-4 Start-Up/Spare Parts			
93-5 Excess Liability Insur.			
93-6 Sales Tax On Indirects			
93-7 Owners Cost			
93-8 EPC Fee			
	11,449,000	138,672,847	USD
94-1 Contingency on Equipment			
94-2 Contingency on Engr Equip			
94-3 Contingency on Material	6,421,000		
94-4 Contingency on Labor	13,444,000		
94-5 Contingency on Sub.	1,316,000		
94-6 Contingency on Equipment	4,265,000		
94-7 Contingency on Indirect	2,290,000		
	27,736,000	166,408,847	USD
96-1 Escalation on Equipment			
96-2 Escalation on Engr Equip			
96-3 Escalation on Material			
96-4 Escalation on Labor			
96-5 Escalation on Sub.			
96-6 Escalation on Process Equ			
96-7 Escalation on Indirect			
		166,408,847	USD
98 - Interest During Constr			
		166,408,847	USD
Total		166,408,847	USD

APPENDIX B

1. ESTIMATED PROJECT SCHEDULES

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Aux Boiler (LNB/OFA/F...		15m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		8m
A1020	Engineering	8m
Procurement of Major Equipment		6m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
A1070	GWC Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		5m
A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	5m
Installation		1m
A1050	Installation	1m
Commissioning & Start-Up		2m
A1060	Commissioning & Start-Up	2m

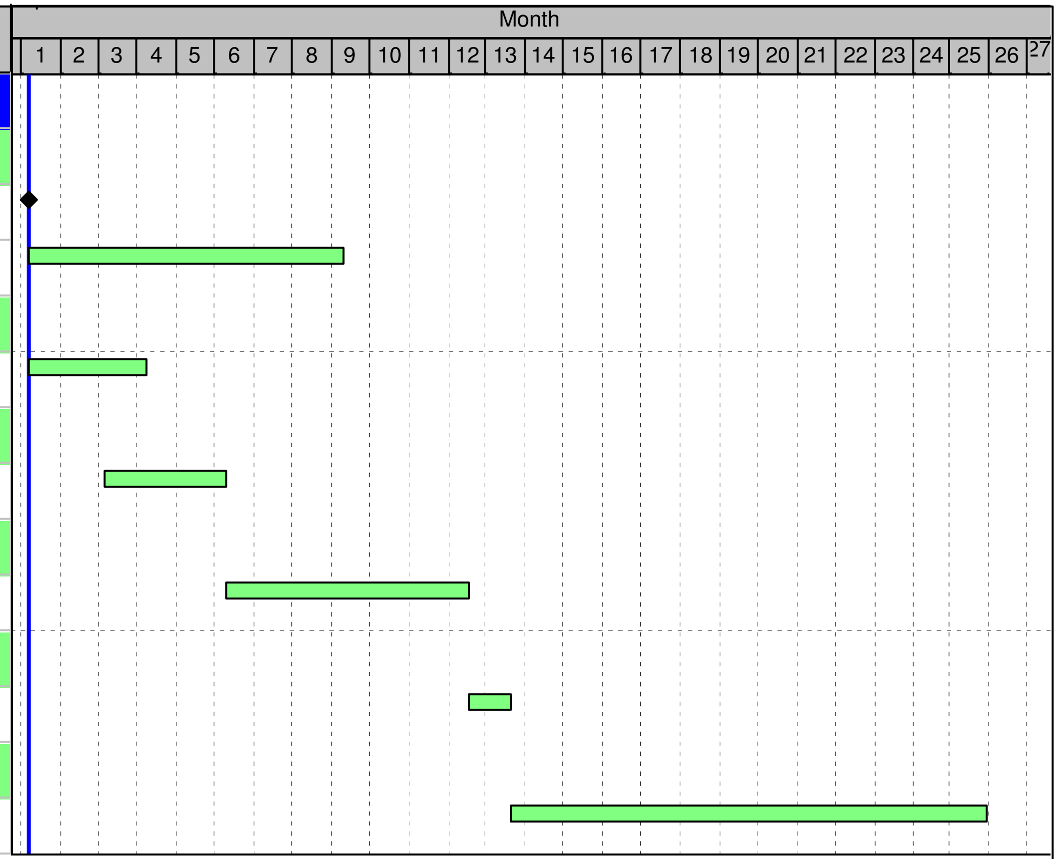


Run Date: 09-17-12

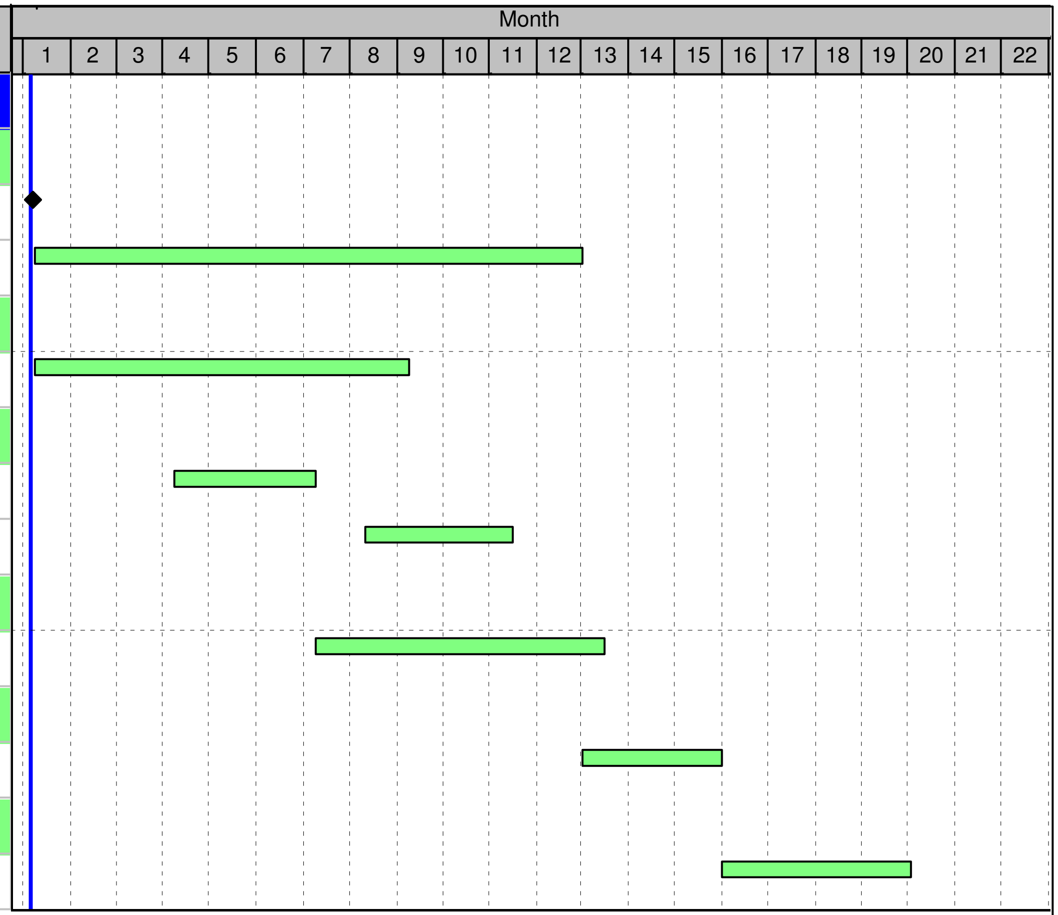
NOx Control Technology Cost and Performance Study for
Entergy Services, Inc. White Bluff and Lake Catherine
Aux Boiler Low NOx Burner/Over-Fire Air/Flue Gas Recirculation (LNB/OFA/FGR)

Sargent & Lundy LLC

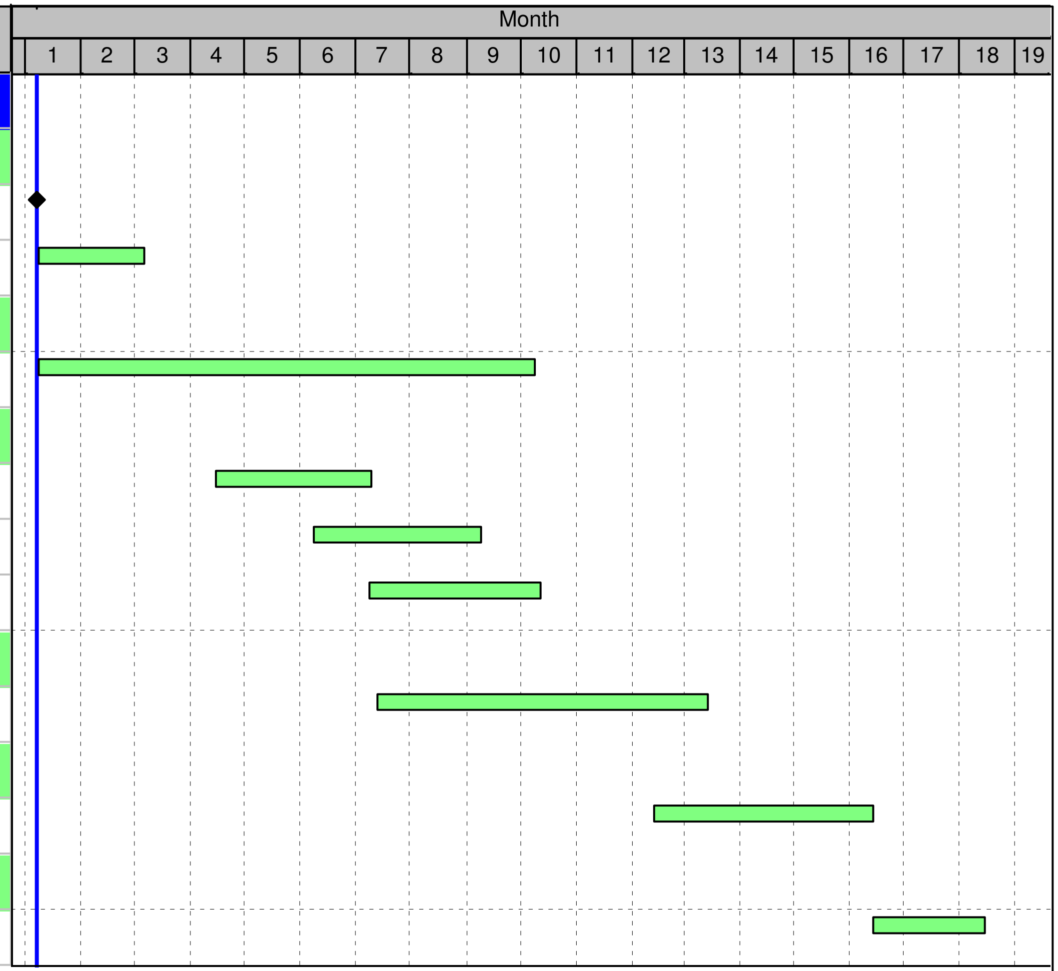
Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Neural Network		24m
Permitting		8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
Engineering		3m
A1020	Engineering	3m
Procurement of Major Equipment		3m
A1030	Neural Network Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		6m
A1040	NN Vendor Engineering/Fabrication/Delivery	6m
Installation		1m
A1050	Installation	1m
Commissioning & Start-Up		12m
A1060	Commissioning & Start-Up	12m



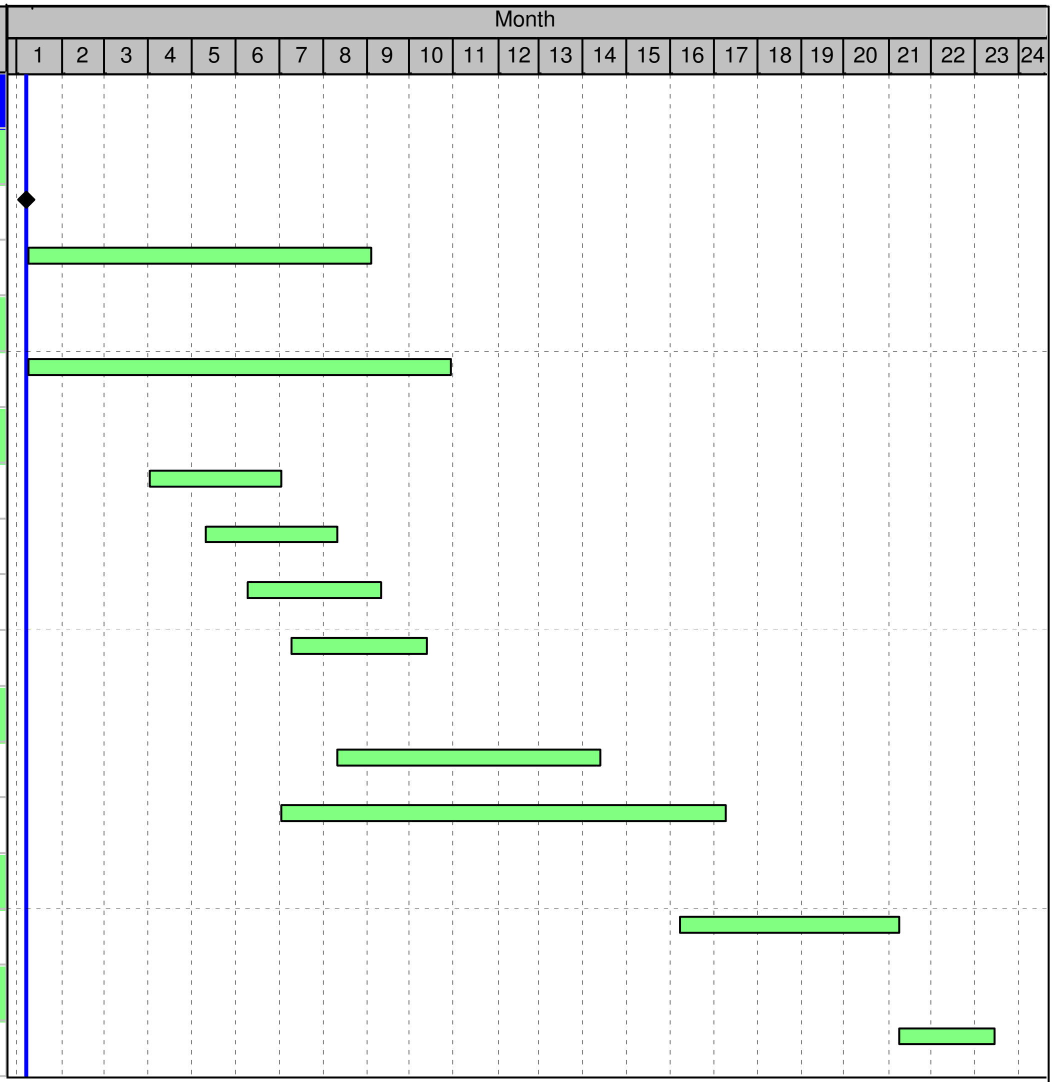
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Low NOx Burners/Over ...	19m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	8m
A1020	Engineering	8m
	Procurement of Major Equipment	7m
A1030	LNB/OFA Spec - Prep/Bid/Eval/Award	3m
A1070	GWC Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	LNB/OFA Vendor Engineering/Fabrication/Delivery	6m
	Installation	3m
A1050	Installation	3m
	Commissioning & Start-Up	4m
A1060	Commissioning & Start-Up	4m



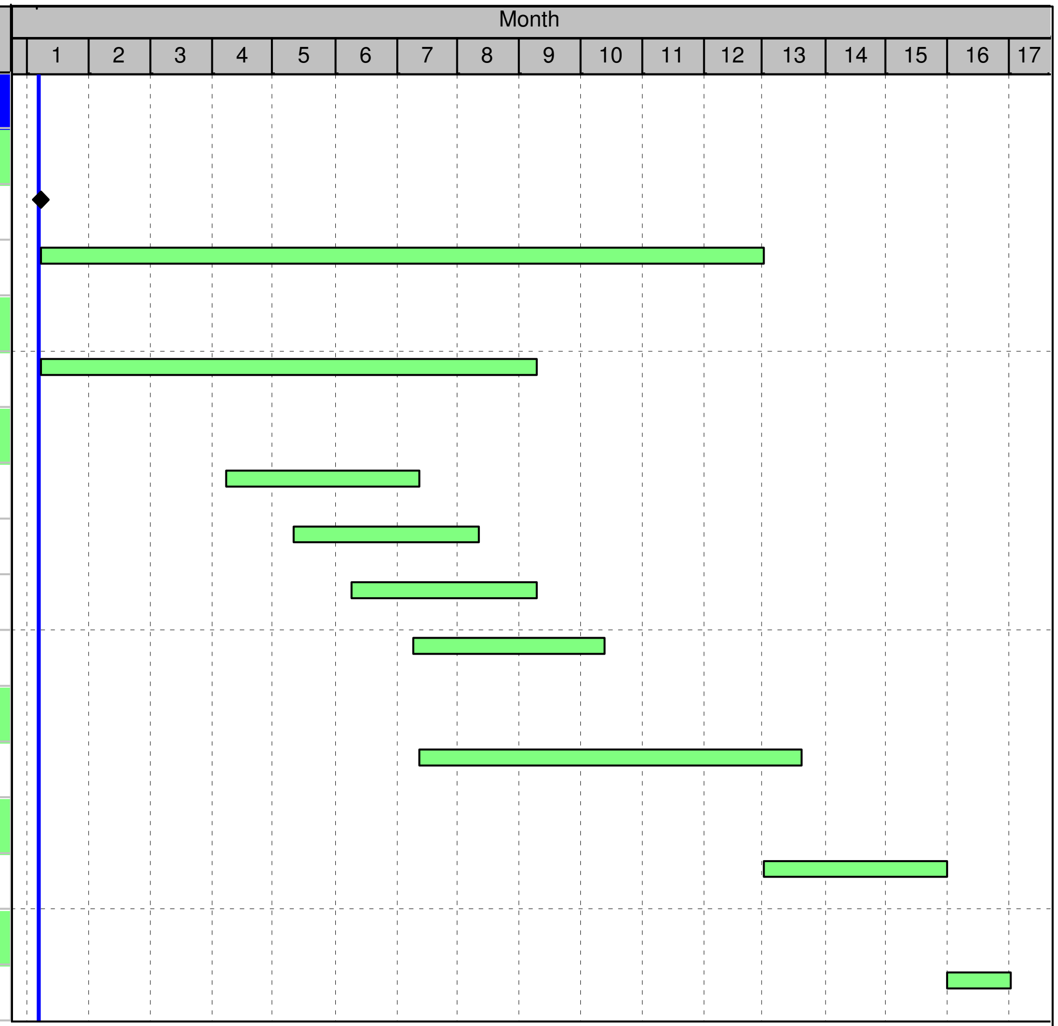
Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Induced Flue Gas Recir...	17m
	Permitting	2m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	2m
	Engineering	9m
A1020	BOP Engineering	9m
	Procurement of Major Equipment	6m
A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
	Installation	4m
A1050	Installation	4m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m



Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Flue Gas Recirculation ...	22m
	Permitting	8m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	8m
	Engineering	10m
A1020	BOP Engineering	10m
	Procurement of Major Equipment	6m
A1150	FGR Fan Procurement Spec - Prep/Bid/Eval/Award	3m
A1140	FGR Duct Procurement Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	10m
A1040	FGR Duct Vendor Engineering/Fabrication/Delivery	6m
A1160	FGR Fan Vendor Engineering/Fabrication/Delivery	10m
	Installation	5m
A1050	Installation	5m
	Commissioning & Start-Up	2m
A1060	Commissioning & Start-Up	2m



Activity ID	Activity Name	Org Dur (months)
	Entergy - NOx Strategy Study - Selective Non-Catalytic ...	16m
	Permitting	12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
	Engineering	8m
A1020	BOP Engineering	8m
	Procurement of Major Equipment	6m
A1030	SNCR Spec - Prep/Bid/Eval/Award	3m
A1070	Civil/Structural Installation Spec - Prep/Bid/Eval/Award	3m
A1080	Mech Installation Spec - Prep/Bid/Eval/Award	3m
A1090	Elec/I&C Installation Spec - Prep/Bid/Eval/Award	3m
	Vendor Engineering/Fab/Delivery	6m
A1040	SNCR Vendor Engineering/Fabrication/Delivery	6m
	Installation	3m
A1050	Installation	3m
	Commissioning & Start-Up	1m
A1060	Commissioning & Start-Up	1m

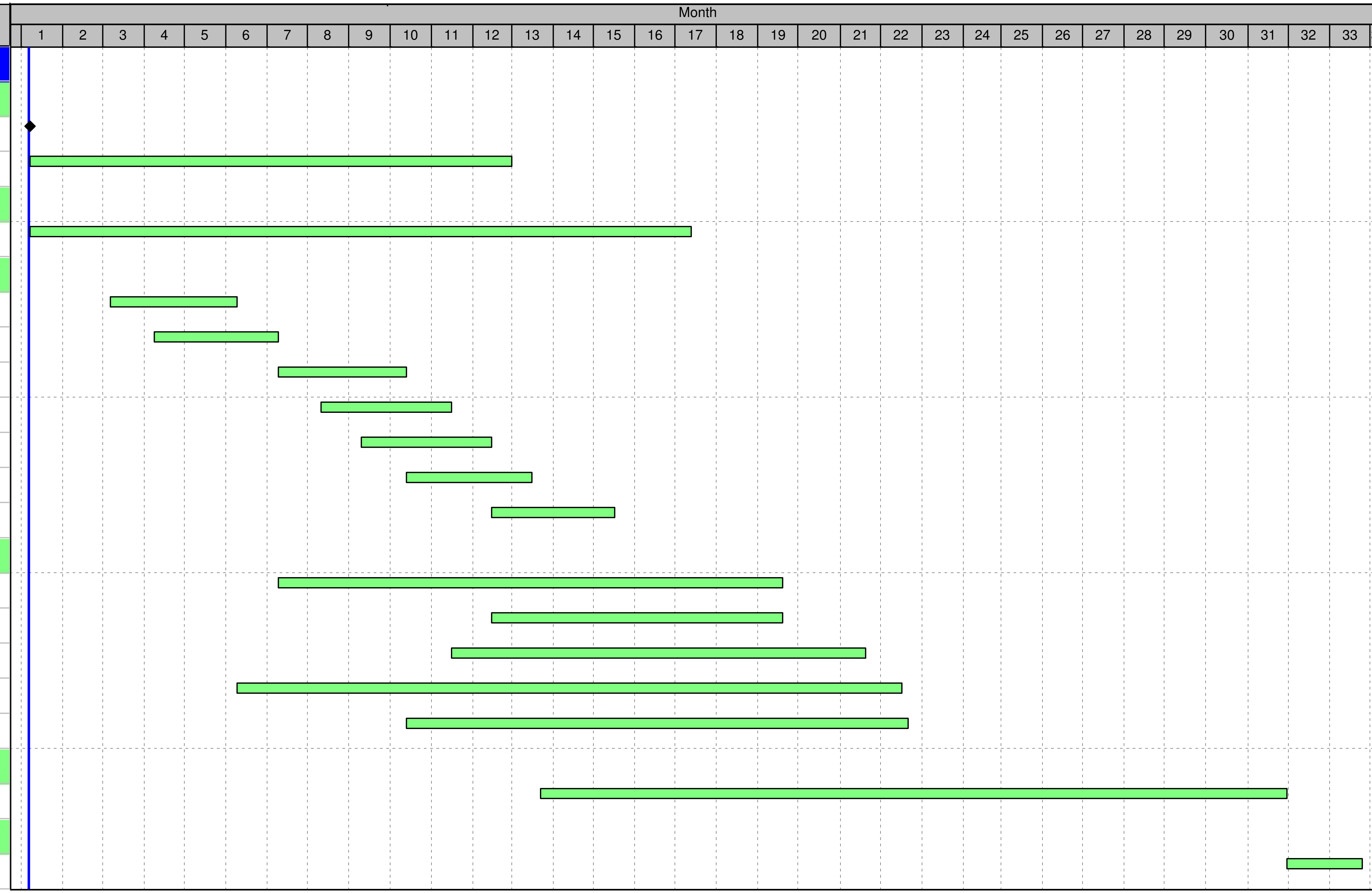


Run Date: 09-14-12

NOx Control Technology Cost and Performance Study for Entergy Services, Inc. White Bluff and Lake Catherine Selective Non-Catalytic Reduction (SNCR)

Sargent & Lundy LLC

Activity ID	Activity Name	Org Dur (months)
Entergy - NOx Strategy Study - Selective Catalytic Red...		32m
Permitting		12m
A1000	Project Authorization	0m
A1010	Air Permit - Prepare/Review/Approve	12m
Engineering		16m
A1020	BOP Engineering	16m
Procurement of Major Equipment		12m
A1140	Ammonia Injection System Procurement Spec - Prep/Bid/Eval/Award	3m
A1150	Catalyst Procurement Spec - Prep/Bid/Eval/Award	3m
A1170	Fan Spec - Prep/Bid/Eval/Award	3m
A1190	Ductwork Spec - Prep/Bid/Eval/Award	3m
A1130	Structural Steel Spec - Prep/Bid/Eval/Award	3m
A1030	Mech Install Spec - Prep/Bid/Eval/Award	3m
A1120	Elec Install Spec - Prep/Bid/Eval/Award	3m
Vendor Engineering/Fab/Delivery		16m
A1160	Catalyst Vendor Engineering/Fabrication/Delivery	12m
A1210	Structural Steel Vendor Engineering/Fabrication/Delivery	7m
A1200	Ductwork Vendor Engineering/Fabrication/Delivery	10m
A1040	Ammonia Injection System Vendor Engineering/Fabrication/Delivery	16m
A1180	Fan Vendor Engineering/Fabrication/Delivery	12m
Installation		18m
A1050	Installation	18m
Commissioning & Start-Up		2m
A1060	Commissioning & Start-Up	2m



APPENDIX C

1. OPERATING AND MAINTENANCE COST ESTIMATES

NO_X Compliance Costs

Unit Name White Bluff 1

Unit Data		Reagent Costs	
Size (Gross kW)	815,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu at full load)	**0.33**	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,981.6	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Coal Cost, $/Mbtu	2.650
Est. Capacity Factor (%)	76.00		
Boiler Type	T/F	Water Cost, $/1000 gal (3)	2
Boiler Eff. (%)	84	Electricity, $/MWh	41.50
Estimated NOx, tons/day Max	**26.936**		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	-		
Fuel -	PRB		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	76.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA (Note 5)	54.5	0.15	4,469	5,363	9.6	$7,804,000	$142,000	$0	$0
Neural Net	10.0	0.30	8,848	983	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.24	7,229	2,602	11.5	$9,372,000	$169,000	$5,377,000	$281,000
LNB+OFA+Full SNCR	61.4	0.13	3,799	6,033	20.0	$16,290,000	$311,000	$4,154,000	$384,000
LNB+OFA+Full SCR	83.3	0.055	1,639	8,193	248.6	$202,601,000	$608,000	$2,836,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) LNB/OFA material already purchased for Unit 1. The total cost to Entergy would be the same for Unit 1 as shown for Unit 2.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

NO_X Compliance Costs

Unit Name White Bluff 2

Unit Data		Reagent Costs	
Size (Gross kW)	844,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu at full load)	**0.39**	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	8,950.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,604.3	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Coal Cost, $/Mbtu	2.650
Est. Capacity Factor (%)	76.00		
Boiler Type	T/F	Water Cost, $/1000 gal (3)	2
Boiler Eff. (%)	84	Electricity, $/MWh	41.50
Estimated NOx, tons/day Max	**31.833**		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	-		
Fuel -	PRB		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	76.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
LNB + OFA	61.5	0.15	4,469	7,150	14.0	$11,831,000	$142,000	$0	$0
Neural Net	10.0	0.35	10,457	1,162	0.3	$250,000	$50,000	$0	$0
Full SNCR	26.5	0.29	8,544	3,076	11.1	$9,372,000	$169,000	$6,338,000	$333,000
LNB+OFA+Full SNCR	67.3	0.13	3,799	7,821	24.1	$20,317,000	$311,000	$4,158,000	$384,000
LNB+OFA+Full SCR	85.9	0.055	1,639	9,981	211.2	$178,240,000	$608,000	$2,858,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 12,000 hours
(5) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

Unit name Lake Catherine Unit 4

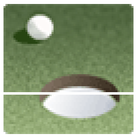
Unit Data		Reagent Costs	
Size (Gross kW)	558,000	Aq.Ammonia $/t	$700
Average NOx Emission Rate (lb/MMBtu)	0.4825	An.Ammonia $/t	$400
Nominal Max. Boiler Heat Input (mmBtu/hr)	5,850.0	Urea $/t	$350
Avg. Heat Rate (Btu/kwh)	10,483.9	N/F-T Urea $/t	$618
Aux. Power (kw)	-	Gas Cost, $/MBtu	4.900
Est. Capacity Factor (%)	10.00	Water Cost, $/1000 gal (3)	2
Boiler Type	T/F	Electricity, $/MWh	41.50
Boiler Eff. (%)	82		
Estimated NOx, tons/day Max	3.387		
Emission Limit, tons	-		
NOx Sales/Buy rate, $/ton	2500.0		
Fuel	Gas		
Seasonal Days	153		
Basis	0		
Analysis - Enter "0" for Annual and 1 for Seasonal			
CF For Variable O&M	10.00		

Technology	Estimated Reduction from Baseline	Emission Rate After Control	Tons of NOx Emission, Seasonal/Annual	Tons of NOx Removed, season/annual	Estimated Capital Cost		Operating & Maintenance Cost: Fixed O&M	Variable O&M, season or yr	Fuel Impact, season or yr
	%	(lb/mmBtu)	tons	tons	$/kW	$/unit	$/yr	$/@CF	$/@CF
Baseline	0	0.4825							
BOOS (at 558 MW)	50.0	0.24	618	618	1.6	$893,000	$21,000	$0	$0
LNB + OFA	60.0	0.19	495	742	15.7	$8,762,000	$210,000	$0	$0
SCR	90.0	0.05	124	1,113	106.8	$59,587,000	$358,000	$254,000	$0
SNCR	40.0	0.29	742	495	27.8	$15,507,000	$279,000	$1,542,000	$98,000
Water Injection	9.1	0.44	1,124	113	3.9	$2,177,000	$52,000	$18,000	$468,000
IFGR (below 500 MW)	19.0	0.39	1,001	235	3.9	$2,166,000	$52,000	$0	$0
FGR	60.0	0.19	495	742	20.6	$11,489,000	$207,000	$142,000	$0
LNB/OFA + SNCR	70.0	0.14	371	865	43.5	$24,269,000	$489,000	$393,000	$69,000
LNB/OFA + SCR	94.0	0.03	74	1,162	122.5	$68,349,000	$568,000	$268,000	$0

(1) Aux. Power cost is calculated based on variation in capacity factor
(2) Assumed water cost of $2/1000 gallons.
(3) Assumed that 15% urea will be used for SNCR technology.
(4) Assumed that initial catalyst life is 40,000 hours.
(5) Water Injection is used only for trimming at high load. Approximately 66% of Hours are affected.
(6) For SCR technology, the variable O&M costs are based on operating at NOx outlet emissions marginally below the compliance emission rate.

APPENDIX D

1. BOOS AT FULL UNIT LOAD



To: DAVID H PARK/Sargentlundy@Sargentlundy,
Cc:
Bcc:
Subject: Fw: BOOS for NOx Control
From: STEVE M KATZBERGER/Sargentlundy - Thursday 03/28/2013 03:32 PM

From: Stephen Wood [mailto:swood@etecinc.net]
Sent: Monday, March 25, 2013 2:20 PM
To: HANTZ, JOSEPH
Subject: BOOS for NOx Control

Joe,

The attached PDF file contains background information on utilizing burners out of service for NOx control, as well as, predicted Lake Catherine Unit 4 burner header pressures and NOx emissions, utilizing the top burner elevation out of service (4BOOS). If you have any questions, please let me know.

Regards,

Steve Wood
Principal Officer
Entropy Technology & Environmental Consultants, Inc. (ETEC Inc.)
12337 Jones Rd. Suite 414
Houston, TX 77070
Ph: 281-807-7007
Cell: 713-253-8230
Fax: 281-807-1414
Website: www.etecinc.net

 BOOS for NOx Control.pdf

Combustion Modification (BOOS) for NOx Control

Implementation of Burner Out Of Service (BOOS) operation is a practical and cost-effective means for achieving staged combustion (i.e., modifying burner stoichoimetry to reduce NOx emissions formation) on an existing gas/oil fired electric utility boiler. Utilizing BOOS operation for NOx control is well documented in the literature, e.g., EPA 456/F-99-006R "Nitrogen Oxides (NOx), Why And How They Are Controlled", November 1999, and EPRI TR-108181 "Retrofit NOx Control Guidelines for Gas- and Oil-Fired Boilers, Version 2.0", June 1997, among numerous others.

The technique of BOOS operation involves terminating the fuel flow to selected burners on the top elevation while leaving the air registers open. The remaining burners operate fuel-rich, thereby limiting oxygen availability, lowering peak flame temperatures, and reducing NOx formation. The un-reacted products combine with the air from the above terminated-fuel burners to complete burnout before exiting the furnace. I have personally been involved with implementing BOOS operation on virtually every gas fired electric utility boiler design across the country since the mid 1970's. In almost every case, the original "high" burner header pressure (BHP) set point had to be increased to accommodate BOOS operation. No adverse operational or maintenance problems corresponding to BOOS implementation have been reported.

BOOS operation can be a very effective NOx reduction technology, depending on the degree of staging, as shown for Ninemile Unit 4 (750 mw CE Tangential Fired) in Figure 1. The corresponding BOOS pattern is shown in Figure 2. The BHP corresponding to 4BOOS operation on Lake Catherine Unit 4 is shown in Figure 3. The "High" BHP set point would need to be increased from 42 to 50 psig. The predicted NOx emissions corresponding to 4BOOS operation are presented in Figure 4.

Figure 1- Stoichiometry Modification (BOOS) NOx Reduction

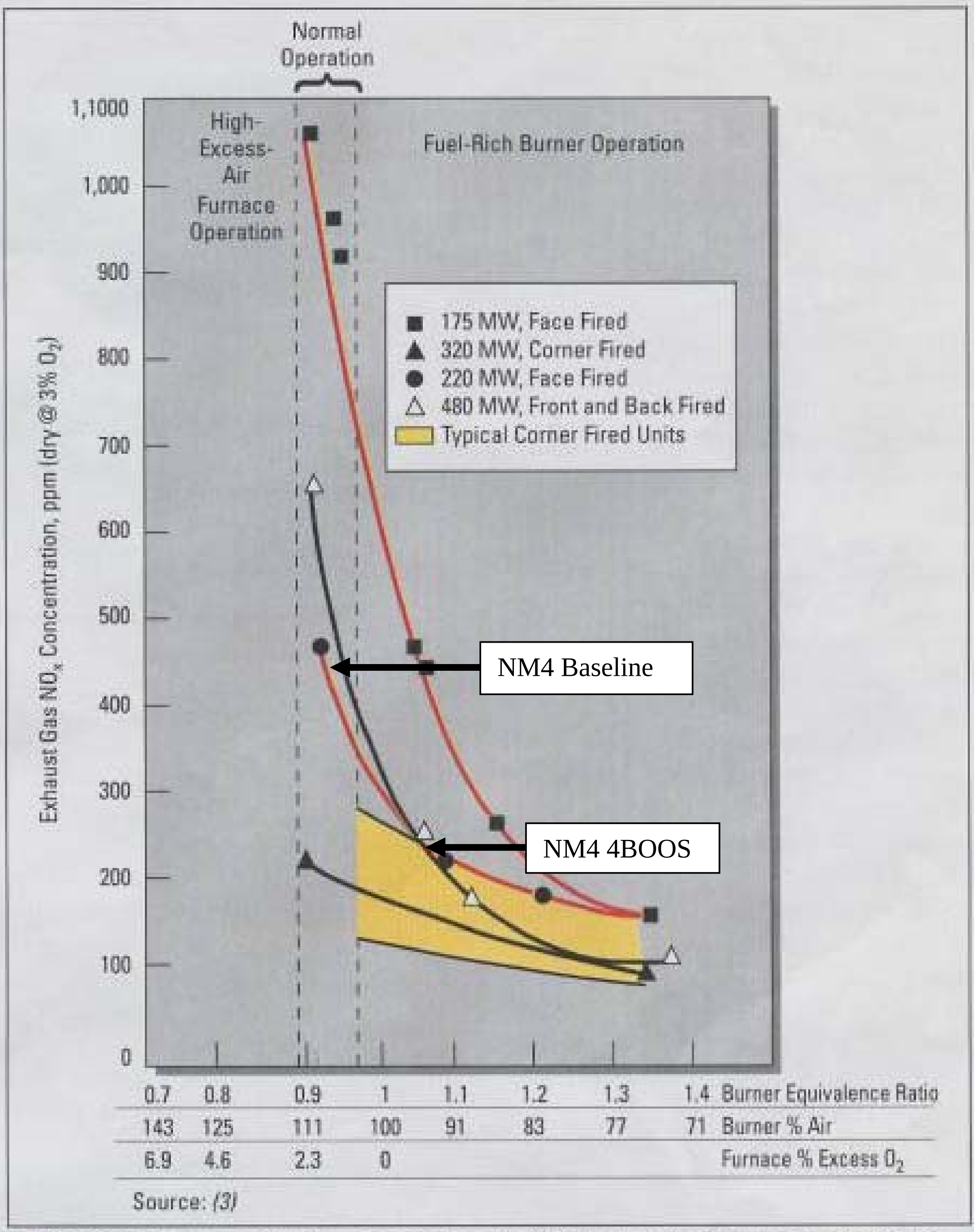


Figure 2. Burners-out-of-service can be an effective combustion staging technique.

Figure 2- Ninemile Units 4 and 5 BOOS Pattern
(Top Elevation Out of Service & Air Registers Open)

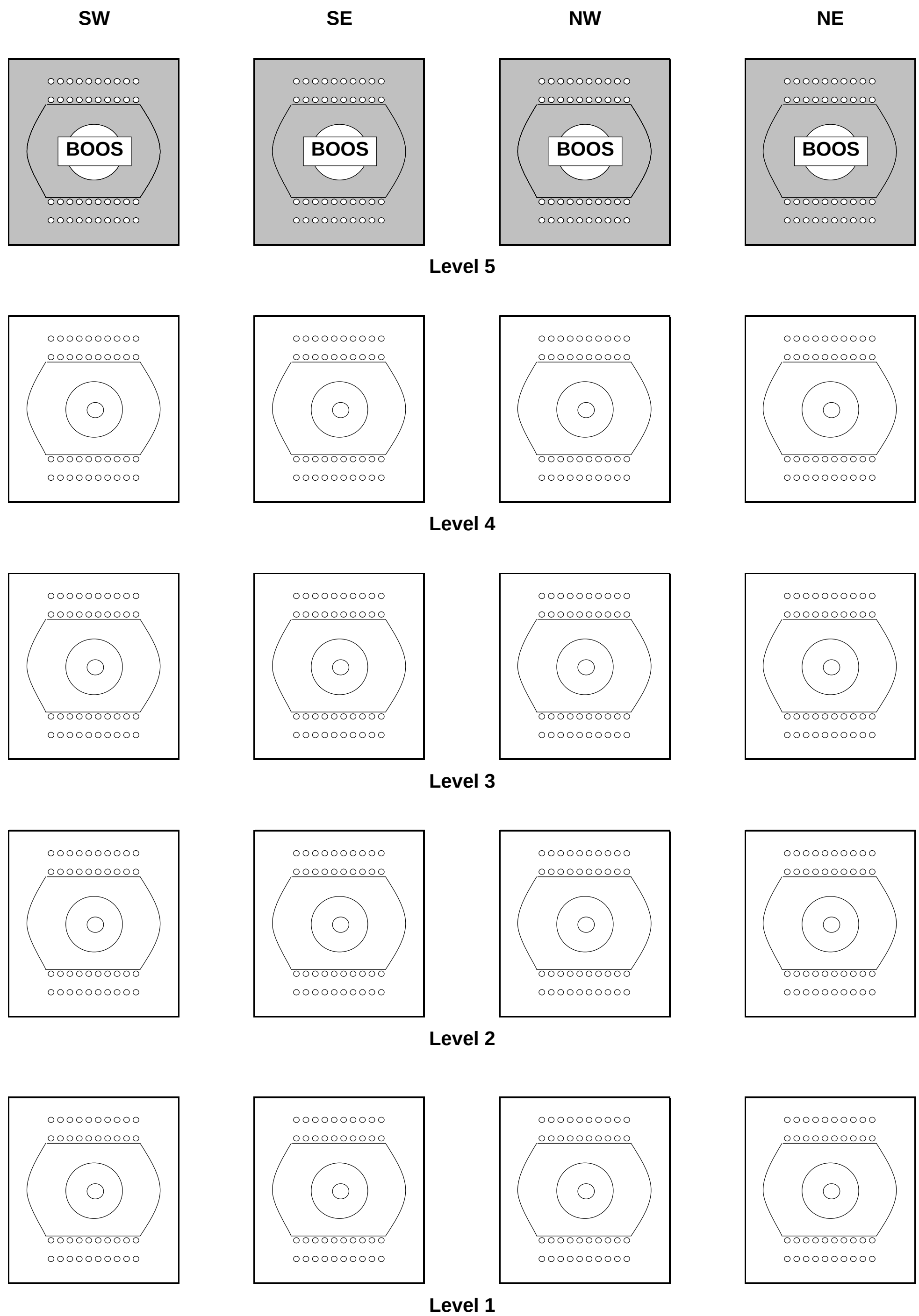


Figure 3- Lake Catherine Unit 4 Burner Header Pressure

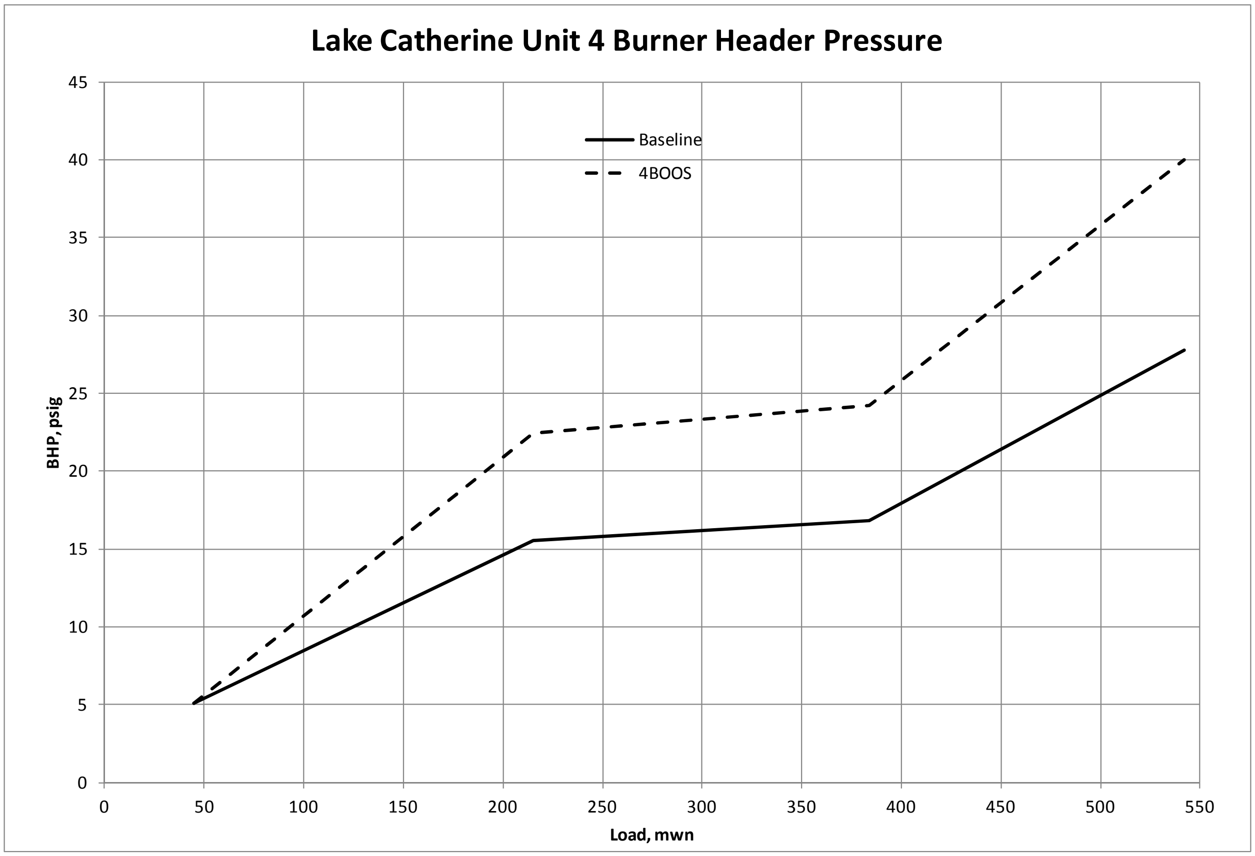
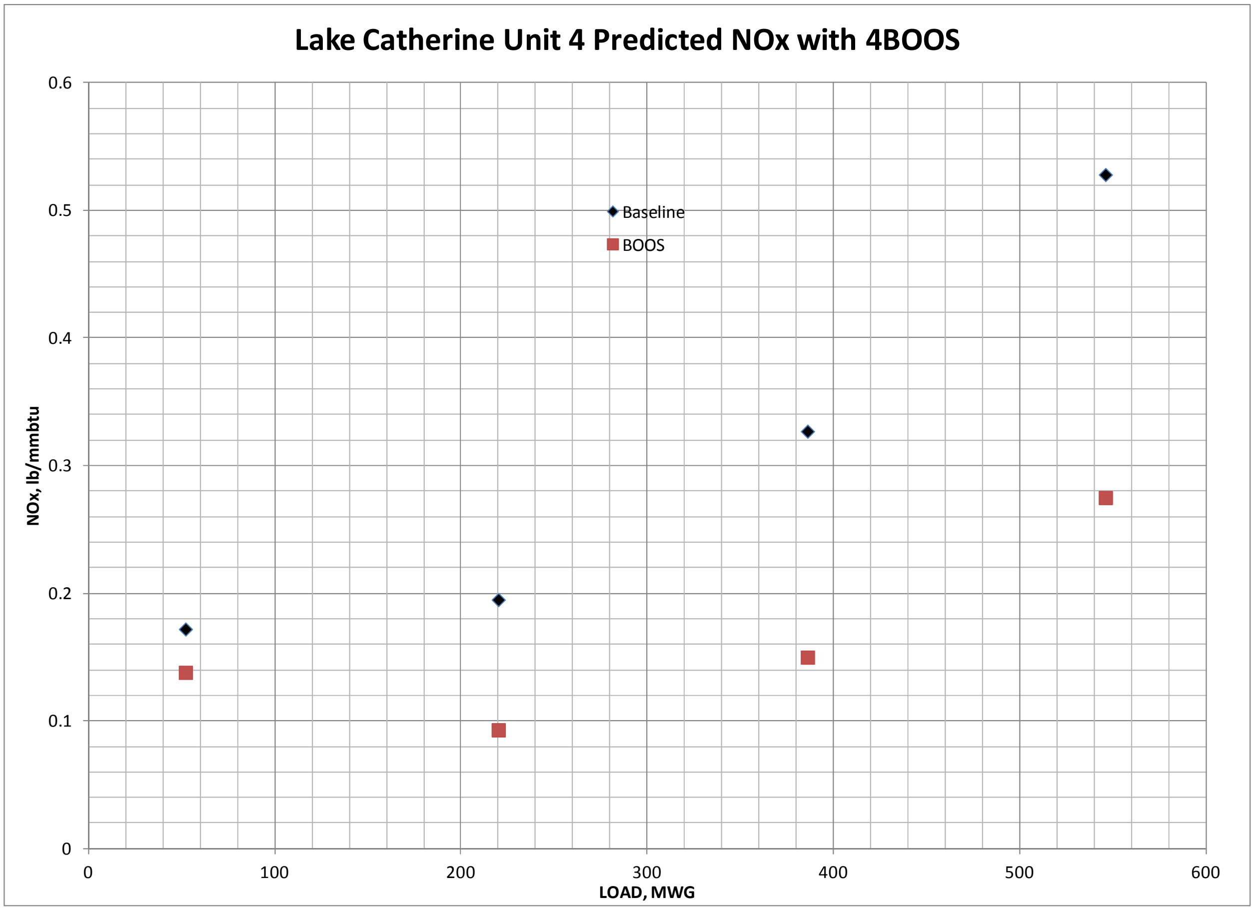


Figure 4- Lake Catherine Unit 4 NOx Emissions Prediction



ADEQ

ARKANSAS

Department of Environmental Quality

April 5, 2017

Kelly McQueen, Assistant General Counsel
Entergy Arkansas, Inc.
425 W Capitol Avenue
P.O. Box 551
Little Rock, Arkansas 72201

Dear Kelly McQueen:

The Arkansas Department of Environmental Quality (ADEQ) is in the process of developing a state implementation plan (SIP) revision to address disapproved provisions in the 2008 Arkansas Regional Haze SIP (2008 AR RH SIP) and replace the federal implementation plan (FIP) promulgated by EPA on September 27, 2016. As part of this process, ADEQ requests that Entergy Arkansas, Inc. (EAI) provide supplemental information to inform ADEQ's best available retrofit technology (BART) determination for sulfur dioxide (SO_2) at White Bluff units 1 and 2.

In the "State of Arkansas Regional Haze and Interstate Visibility Transport Federal Implementation Plan" (AR RH FIP), EPA determined that BART for White Bluff was dry flue gas desulfurization (Dry FGD) technology based on the thirty year expected useful life of the Dry FGD equipment; however, EPA did not appropriately take into account the remaining useful life of the White Bluff units themselves. White Bluff unit 1 began operating in 1980 and unit 2 began operating in 1981. Given the age of the units and expected market trends for coal compared to other fuels and technologies used to generate electricity, it is not reasonable to assume that White Bluff will still be powered by coal in 2051 (thirty years after the compliance date in the AR RH FIP and 70 years after beginning operation) and to base cost-effectiveness calculations on such an assumption.

EAI has provided several analyses in support of comments on EPA's AR RH FIP with various assumptions about dates by which Entergy could commit to cease coal-fired operations at White Bluff units and what interim controls would be necessary to satisfy BART requirements under 40 CFR 51 Appendix Y. ADEQ requests that EAI confirm whether such analyses that are already on the record are still accurate. Specifically, please confirm whether the cost-effectiveness values for Dry FGD of approximately $10,400–11,800 per ton under the assumption of four to five years of remaining useful life is still accurate. Additionally, please confirm whether the cost-effectiveness values for Dry FGD of approximately $7,500 to $8,500 per ton under the assumption of six to seven years of remaining useful life is still accurate. Please provide a cost-effectiveness estimate for meeting a 0.6 lb/MMBtu on a 30-day rolling average limit for SO_2

based on the use of low-sulfur coal compared to White Bluff's currently permitted emission limit of 1.2 lb/MMBtu proposed in comments dated August 7, 2015 to EPA on the AR RH FIP.

In addition to verifying cost-effectiveness values already on the record, ADEQ requests that EAI also provide additional supplemental information for consideration. Specifically, please provide an analysis of the expected cost-effectiveness values for Dry FGD with compliance based on the following scenarios: seven to eight years remaining useful life, fifteen years remaining useful life (EPA's assumption for financing control equipment in the IPM model), and nineteen years remaining useful life (sixty years from the start of operations at White Bluff).

We request that EAI provide this supplemental information by 4:30 p.m. on April 21, 2017. Thank you for your prompt response to this request for supplemental information.

Sincerely,

Stuart Spencer
Associate Director, Office of Air Quality

Arkansas Environmental Support
425 West Capitol Avenue
A-TCBY-22D
Little Rock, AR 72203
Tel 501-377-4033
Fax 281-297-6128
G. Tracy Johnson, Manager
Arkansas Environmental Support

AR-17-039

April 21, 2017

Stuart Spencer
Associate Director
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

Re: Response to Information Request
Entergy Arkansas, Inc. – White Bluff Plant
AFIN: 35-00110 Permit No.: 0263-AOP-R10

Dear Mr. Spencer:

On behalf of Entergy Arkansas, Inc. (EAI), Entergy Services, Inc. (ESI) has reviewed your letter of April 5, 2017, regarding costs associated with potential SO_2 emissions control options at the White Bluff Plant. As requested, ESI provides the following responses to the questions posed by ADEQ in this letter. For convenience, these responses have been numbered in the order they appear in the April 5 letter.

Please note that, for all costs associated with dry flue gas desulfurization (dry FGD) controls, two separate cost ranges are provided. The first is the full capital cost estimate prepared by Sargent and Lundy (S&L) for Entergy, based on S&L's extensive experience estimating costs for similar projects at similar electric generating facilities. While ESI believes the full S&L capital cost estimate to be the most accurate representation of costs that would be borne by EAI and its ratepayers, the U.S. EPA has previously disallowed consideration of several components of this cost estimate, including escalation, interest during construction (IDC), and owner's costs. Recognizing this, ESI is also providing a second, partial, cost range that eliminates escalation, IDC, and owner's costs, even though the removal of such costs severely underestimates the actual amount EAI would incur to install SO_2 emissions controls at White Bluff. All capital costs are from S&L estimate 33787B issued November 18, 2016.[1] O&M costs are the same for both scenarios and are from S&L report SL-012831 issued July 14, 2015. All costs are in 2015 dollars.

1. **Please confirm whether the cost-effectiveness values for Dry FGD of approximately $10,400 – 11,800 per ton under the assumption of four to five years of remaining useful life is still accurate.**

   For a four- to five-year remaining useful life (RUL), the cost-effectiveness range in dollars per ton of SO_2 emissions reduced is approximately $9,100-$11,000 based on the full costs and $6,900 to $8,200 based on the partial costs.

2. **Please confirm whether the cost effectiveness values for dry FGD of approximately $7,500 to $8,500 per ton under the assumption of six-to-seven years of remaining useful life is still accurate.**

   For a six- to seven-year RUL, the cost-effectiveness range in dollars per ton of SO_2 emissions reduced is approximately $7,100-$8,000 based on the full costs and $5,400-$6,100 based on the partial costs.[2]

[1] S&L revised its prior cost estimates, as explained in EAI's Petition for Reconsideration of the final FIP. *See* EAI Petition for Reconsideration, at 8 n. 31 (Nov. 23, 2016). These revised cost estimates have been used to respond to the Department's questions.
[2] EAI Petition for Reconsideration, at 8.

3. **Please provide a cost-effectiveness estimate for meeting a 0.6 lb/MMBtu on a 30-day rolling average limit for SO_2 based on the use of low-sulfur coal compared to White Bluff's currently permitted emission limit of 1.2 lb/MMBtu proposed in comments dated August 7, 2015 on the AR RH FIP.**

   To meet an emission limit of 0.6 lb/MMBtu, EAI would purchase coal with a sulfur content lower than 0.6 lb/MMBtu to provide an adequate margin for compliance. Based on coal market information available to Entergy's fuel supply group, the cost premium for coal purchased to meet a SO_2 limit of 0.6 lb/MMBtu is expected to be approximately 50 cents per ton of coal purchased. Based on this cost premium, a typical low-sulfur coal heat content of 8,800 btu/lb (as supplied), and the annual heat input value utilized in the S&L dry FGD cost estimate (55,829,551 MMBtu/year), the annual cost premium associated with the use of low-sulfur coal at one White Bluff unit is estimated to be approximately $1,600,000.[3]

4. **Please provide an analysis of the expected cost-effectiveness values for dry FGD with compliance based on the following scenarios:**

   a. **Seven to eight years of remaining useful life,**

      For a seven- to eight-year RUL, the cost-effectiveness range in dollars per ton of SO_2 emissions reduced is approximately $6,500-$7,200 based on the full costs and $5,000-$5,500 based on the partial costs.

   b. **Fifteen years remaining useful life (EPA's assumption for financing control equipment in the IPM model), and;**

      For a 15-year RUL, the cost-effectiveness in dollars per ton of SO_2 emissions reduced is approximately $4,500 based on the full costs and $3,500 based on the partial costs.

   c. **Nineteen years of remaining useful life (sixty years from the start of operations at White Bluff).**

      For a 19-year RUL, the cost-effectiveness in dollars per ton of SO_2 emissions reduced is approximately $4,050 based on the full costs and $3,175 based on the partial costs. It should be noted that the White Bluff units first began commercial operation on August 21, 1980 (Unit 1) and July 23, 1981 (Unit 2). Assuming that compliance with a SIP limit for a dry FGD system would be required in 2022, a 19-year RUL would end in 2041.

We appreciate the Department's consideration of this information. Should you or your staff have any further questions or require any additional information, please feel free to contact me at (501) 377-5760, Tracy Johnson at (501) 377-4033, or David Triplett at (501) 377-4030.

Sincerely,

Kelly McQueen

Associate General Counsel

KMM/dct

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[3] EAI cannot estimate the cost-effectiveness of meeting a SO_2 limit of 0.6 lb/MMBtu based on the use of low sulfur coal given that the actual sulfur content of low sulfur coal varies, making it difficult to estimate the tons of SO_2 that would be reduced, particularly in comparison to the historical emissions. Furthermore, to estimate a predicted annual average SO_2 emission rate based on operation with low sulfur coal could under-estimate the cost effectiveness of this option.

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Kelly McQueen
Assistant General Counsel

August 18, 2017

Stuart Spencer
Associate Director
Office of Air Quality
Arkansas Department of Environmental Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

Re: Updated BART Five-Factor Analysis for SO_2 at Entergy White Bluff Units 1 and 2

Dear Mr. Spencer:

Entergy Arkansas, Inc. (Entergy) respectfully submits the following Updated Best Available Retrofit Technology (BART) Five-Factor Analysis (FFA) for sulfur dioxide (SO_2) for Units 1 and 2 at the White Bluff Steam Electric Station (Updated FFA). The submittal is an update to the original FFA submitted on February 21, 2013, with revisions on June 10 and October 15, 2013. Confidential Business Information has been redacted. A hard copy of the Updated FFA which includes the redacted information will be submitted to the Department concurrently, in accordance with Regulation No. 18.1402.

The Updated FFA updates the emissions baseline period used for modeling White Bluff's baseline visibility impairment and estimate the cost-effectiveness of the SO_2 controls evaluated, incorporates new information regarding the remaining useful life (RUL) of the units, assesses a new control scenario representing combustion of only low-sulfur coal (LSC), incorporates additional information related to control options involving Dry Sorbent Injection (DSI), updates the modeling to reflect the newest methodologies for speciating particulate matter emissions into its constituents, and amends the SO_2 BART conclusion in light of the new information. The Updated FFA concludes that combustion of LSC constitutes BART for White Bluff Units 1 and 2 in light of the updated RUL. The proposed BART emission rate for SO_2 for each unit is 0.6 pounds per MMBtu (lb/MMBtu) on a rolling 30-day average. Entergy urges ADEQ to incorporate this analysis into its anticipated revisions to the SO_2 provisions in the Regional Haze State Implementation Plan (SIP) for the first planning period.

The Updated FFA addresses only SO_2 BART, and does not address BART for nitrogen oxides (NOx). Last month, ADEQ released a draft Regional Haze SIP Revision for the first planning period that concludes compliance with the updated Cross-State Air Pollution Rule constitutes BART for NOx. Entergy submitted comments in support of this conclusion on August 14, 2017. Nonetheless, Entergy would be amenable to accepting a specific emission limit for NOx at White Bluff Units 1 and 2, based on the installation of low NOx burners and separated overfire air (LNB/SOFA), but is still in the process of tuning the LNB/SOFA recently installed at White Bluff Unit 2.

We are happy to answer any questions you may have about the Updated FFA.

Sincerely,

Kelly M. McQueen
Assistant General Counsel –
Environmental (Lead)
Entergy Services, Inc.

Attachment:

Updated Five Factor Analysis

Entergy Services, Inc., on behalf of Entergy Arkansas, Inc.
White Bluff Steam Electric Station
Redfield, Arkansas (AFIN 35-00110)

Updated BART Five-Factor Analysis for SO_2 for Units 1 and 2

Submitted to:

Arkansas Department of Environmental Quality (ADEQ)
Office of Air Quality
5301 Northshore Drive
North Little Rock, AR 72118-5317

Prepared by:

TRINITY CONSULTANTS
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August 18, 2017

Trinity Project 173702.0014

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1 EXECUTIVE SUMMARY

This report provides an update to the Best Available Retrofit Technology (BART) Five Factor Analysis for sulfur dioxide (SO_2) for Unit 1 (SN-01) and Unit 2 (SN-02) at Entergy Arkansas, Inc.'s (EAI's) White Bluff Steam Electric Station (White Bluff) as well as revising the SO_2 BART conclusion. EAI submitted the original BART Five Factor Analysis to the Arkansas Department of Environmental Quality (ADEQ) on February 21, 2013, with revisions on June 10, 2013 and October 15, 2013.

- Unit 1 (SN-01) is a primary boiler with a maximum net power rating of 850 megawatts (MW) and a nominal heat input capacity of 8,950 million British thermal units per hour (MMBtu/hr). The boiler burns sub-bituminous or bituminous coal[1] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an electrostatic precipitator (ESP) for particulate matter (PM) control.
- Unit 2 (SN-02) is identical in design to Unit 1. It is a primary boiler with a maximum net power rating of 850 MW and a nominal heat input capacity of 8,950 MMBtu/hr. The boiler burns sub-bituminous or bituminous coal[2] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an ESP for PM control.

Specific updates incorporated in this version of the report are outlined below.

1.1 REPORT UPDATES

This report includes the following updates to the previous SO_2 Five Factor Analysis for White Bluff Units 1 and 2:

1. Updating the baseline period to 2009-2013.

[redacted]

3. Incorporating a new control scenario representing combustion of only low-sulfur coal (LSC).

4. Incorporating additional information (i.e., cost information and modeling results) related to control options involving Dry Sorbent Injection (DSI).

5. Updating all modeling to reflect the newest methodologies for dividing ("speciating") particulate matter (PM or PM_{10})[3] emissions into its constituents.

6. Updating the SO_2 BART conclusion in consideration of the new information and updates listed above.

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[1] The coal-fired units at White Bluff primarily burn sub-bituminous coal, but are permitted to burn bituminous or sub-bituminous coal. Only sub-bituminous coals were burned during the baseline periods evaluated in this analysis.

[2] Ibid.

[3] All PM represented in this report is assumed to have a mass mean diameter smaller than ten microns.

1.2 SUMMARY OF UPDATED BART FIVE FACTOR ANALYSIS

Trinity conducted the below five-step analysis based on EPA's BART Guidelines[4] in 40 CFR Part 51 and other EPA guidance[5] to evaluate SO_2 BART for Units 1 and 2:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

The updated BART Five Factor Analysis concludes that combustion of LSC constitutes BART for Unit 1 and Unit 2 in light of the updated RUL. The proposed BART emission rate for SO_2 is 0.6 pounds per MMBtu (lb/MMBtu) on a rolling 30-day average.

[4] The BART guidelines were published as amendments to EPA's Regional Haze Rule (RHR) at 40 CFR 51.308 on July 6, 2005.

[5] April 26, 2012, letter from Mr. Guy Donaldson, EPA Region VI, to Mr. Anthony Davis, ADEQ.

2 INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962, and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." For the purpose of determining which sources are subject to BART, a 1.0 Δdv change or more from an individual source is considered to "cause" visibility impairment, and a change of 0.5 Δdv is considered to "contribute" to impairment, which therefore establishes 0.5 Δdv as a numerical screening threshold for subject-to-BART determinations.[6] According to the BART guidelines, the CALPUFF modeling system (CALPUFF) or any other appropriate dispersion model can be used to predict the visibility impacts.[7] The model-predicted visibility impact, specifically when using CALPUFF the 98th percentile impact measured against natural background (and not the maximum impact), is compared to the 0.5 Δdv threshold to determine if the source is anticipated to cause or contribute to the visibility impairment.[8]

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non-air quality*

[6] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule," 70 Fed. Reg. 39,116-18 (July 6, 2005).

[7] Trinity and EAI assert that CALPUFF is not the most appropriate model for estimating visibility impacts. Due to its numerous inherent limitations (e.g., limited chemistry mechanism, distance limitations, blanket background ammonia values, etc.), CALPUFF does not yield reliable results. Furthermore, CALPUFF is no longer an EPA-preferred model, which further indicates CALPUFF's unreliability. More advanced models like the Comprehensive Air Quality Model with Extensions (CAMx)—if processed appropriately—can yield more reliable characterizations of visibility impairment. Nevertheless (without waiver), CALPUFF modeling will continue to be presented in this report for consistency with past submittals.

[8] Id. at 39,163.

environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

The BART Guidelines state that a BART determination should address the following five statutory factors:

1. Existing controls;
2. Cost of controls;
3. Energy and non-air quality environmental impacts;
4. Remaining useful life of the source; and
5. Degree of visibility improvement as a result of controls.

Further, the BART Guidelines indicate that the five basic steps in a BART analysis can be summarized as follows:

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

As described in the above-referenced, previous submittals, the boilers at White Bluff meet the three BART-eligibility criteria, and the existing visibility impairment is modeled at greater than 0.5 Δdv in at least one Class I area. Thus, the White Bluff units are subject to BART.

3 EXISTING EMISSIONS AND BASELINE VISIBILITY IMPAIRMENT

Five Factor Analyses require the determination of unit-specific baseline visibility impairment values to which any post-control scenarios can be compared. The unit-specific baseline modeling analyses are built upon, but are distinguished from, the baseline (a.k.a., "screening") modeling for the collection of BART eligible units at each source that is completed to determine if a BART eligible source is subject to BART. EAI is not updating the subject-to-BART determination at this time.

This section summarizes the baseline visibility impairment attributable to each of White Bluff's units based on CALPUFF air quality modeling conducted by Trinity.[9] Trinity conducted the modeling using the same protocol, methodologies, and inputs (except where specifically updated as described in this report) as presented in the October 15, 2013 submittal. The protocol and details method descriptions are not included with this report because nothing has changed and the CALMET dataset developed per the protocol has been used – and approved by EPA – numerous times since its development.

While this report updates the BART Five Factor Analysis for SO_2 emissions specifically, BART modeling must consider emissions of all visibility-affecting pollutants (VAP), including SO_2, oxides of nitrogen (NO_X), and speciated particulate matter, including filterable coarse particulate matter (PMc), filterable fine particulate matter (PMf), elemental carbon (EC), inorganic condensable particulate matter (IOR CPM) as sulfates (SO_4), and organic condensable particulate matter (OR CPM), also referred to as secondary organic aerosols (SOA).

3.1 BASELINE EMISSION RATES

The updated modeled NO_X and SO_2 emission rates for Unit 1 and Unit 2 are the highest actual 24-hour emission rates based on Clean Air Markets Database (CAMD) data from 2009-2013.[10] The updated modeled PM_{10} emission rates for Unit 1 and Unit 2 are based on emission factors from AP-42 for filterable PM_{10} and condensable PM (with a 99.5 percent control efficiency for ESP applied to the PM_{10} filterable fraction) used in conjunction with the average 2009-2013 coal heating value and ash content (as a percentage of mass).[11] Emission rates for specific PM_{10} species were calculated using the monitored filterable PM rate and the National Park Service (NPS) "speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*[12] except for SO_4, which was calculated using an Electric Power Research Institute (EPRI) methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[13] Table 3-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions.

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[9] See footnote 7, above.

[10] The use of this baseline is a conservative approach. EAI would be justified in using a more recent baseline with lower emissions that would result in higher cost effectiveness values.

[11] AP-42, Chapter 1 External Combustion Sources, Section 1.1 Bituminous and Subbituminous Coal Combustion, Table 1.1-5, page 1.1-24 (September 1998).

[12] The baseline speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. Based on average 2009-2013 values, the following input values were used: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at both White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[13] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 3-1. Baseline Maximum 24-hour Emission Rates (As Hourly Equivalents)

Unit	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
SN-01	6,771.9	3,355.4	119.2	5.1	40.4	31.1	9.3	1.2
SN-02	6,622.3	3,590.5	119.2	5.0	40.4	31.1	9.3	1.2

3.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to estimate the current visibility impairment attributable to Unit 1 and Unit 2 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.[14] Table 3-2 provides a summary of the modeled visibility impairment attributable to Unit 1 and Unit 2 based on the emission rates shown in Table 3-1. This table shows the 98th percentile impacts in Δdv and the number of days with impacts greater than 0.5 Δdv.

Table 3-2. Baseline Visibility Impairment

Unit	Year [A]	CACR		UPBU		HERC		MING	
		98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5
SN-01	2001	1.505	38	1.051	30	0.925	24	0.802	16
	2002	1.306	29	0.742	15	0.567	10	0.708	21
	2003	1.053	32	1.033	24	0.704	15	0.666	14
SN-02	2001	1.533	39	1.059	30	0.912	25	0.819	15
	2002	1.322	29	0.739	16	0.568	11	0.719	20
	2003	1.059	32	1.03	25	0.72	16	0.678	14

[A] Meteorological data year modeled.

[14] Due to an EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset), which excluded the Sipsey Class 1 Area from the modeling domain, Sipsey was not included in this analysis. See also footnote 7 above.

4.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

The boilers burn primarily coal. Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from Unit 1 and Unit 2, the BART analysis is specific to emissions of SO_2. Reductions in emissions of SO_2 are expected to reduce visibility impairment by reducing sulfate (SO_4) formation.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for Unit 1 and Unit 2 are summarized in Table 4-1.

Table 4-1. Available SO_2 Control Technologies for Unit 1 and Unit 2

SO_2 Control Technologies
Fuel Switching – Low-Sulfur Coal (LSC)
Dry Sorbent Injection (DSI)
Dry / Semi-Dry Flue Gas Desulfurization (DFGD), e.g., Spray Dryer Absorber (SDA)
Wet Scrubbing, i.e., Wet Flue Gas Desulfurization (WFGD)

4.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

4.2.1 Fuel Switching - Low-Sulfur Coal

With an achievable emission level of 0.6 lb/MMBtu, switching to LSC can reduce SO_2 emissions by approximately 8.75 percent compared to baseline levels.[15]

4.2.2 Dry Sorbent Injection

DSI involves the injection of a sorbent (e.g., Trona) into the exhaust gas stream where acid gases such as hydrogen chloride (HCl) and SO_2 react with and become entrained in the sorbent. The stream then passes through a particulate control device to remove the sorbent along with the entrained SO_2. The process was developed as a lower cost FGD option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream rather than in a separate vessel. Sorbent injection control efficiency depends on residence time, gas stream temperature, and limitations of the particulate control device.

---

[15] Calculated based on a comparison of the maximum 30 boiler operating day SO_2 emission rate during the baseline period to the proposed limit for low-sulfur coal of 0.6 lb/MMBtu.

DSI is a technically feasible yet seldom used technology for moderate to high removal of SO_2 from coal-fired power plants, with limited full-scale installations for SO_2 control. A significant amount of testing of DSI for SO_2 control has been performed in recent years. This testing has shown that a wide range of performance is achievable (up to 80 or 90 percent SO_2 reduction in some cases). However, this testing has also shown that there are many factors that can impact the performance of these reagents, including particle size (milling), residence time, temperature, and the particulate collection equipment. The primary lesson learned through this testing is that each unit is unique, with various factors that can impact the achievable performance or required reagent feed rate. Different performance has even been seen on sister units. Therefore, it is critical to perform a demonstration or Proof of Concept test at each facility.

A demonstration has not to-date been performed on the White Bluff units to show the achievable SO_2 control and associated reagent feed rates. The cost reports developed by S&L, included in Appendix A, show predicted performance and required reagent rates based on Sargent & Lundy's (S&L's) extensive experience with DSI testing and previous work with the White Bluff units. Two DSI technologies are considered for White Bluff: "DSI", which would utilize the existing ESP, and "enhanced DSI", which would include installation of a fabric filter or baghouse. Enhanced DSI should achieve greater SO_2 reductions because the installation of a fabric filter increases residence time and improves collection efficiency to allow more sorbent to be injected. The S&L reports present predicted performance levels (SO_2 emission rates) for DSI and enhanced DSI of 0.35 lb/MMBtu and 0.15 lb/MMBtu, respectively. Because the actual performance and required reagent rates may vary from the predicted values due to unforeseen site-specific conditions, it is possible that the capital and annual costs represented in the S&L reports, and in Section 4.4.2 of this report, could also vary. If a significantly higher injection rate were actually required to achieve the same performance level (SO_2 emission rate) then the capital and annual costs, and corresponding cost-effectiveness of the DSI technologies, could dramatically increase.

Furthermore, DSI has yet to be demonstrated on similarly sized units to those at White Bluff. An important consideration for DSI technology is the design throughput of the system, beyond just the size and achievable performance (SO_2 emission rate). The largest DSI system installed and operating has a design feed rate of 12 tons/hour, while most of the installed systems inject approximately five to six tons/hour. The predicted injection rate for the White Bluff enhanced DSI case is approximately 15 tons/hour. The greater the injection rates, the more issues associated with supply and delivery logistics that arise. At 15 tons/hour (per unit) White Bluff would consume one railcar (100-ton capacity) of Trona every 3.3 hours if both units are operating at full load.

Prior to moving forward with DSI technology as a compliance strategy, a demonstration test would need to be performed to confirm the feasibility, achievable performance and balance of plant impacts (brown plume formation, ash handling modifications, landfill/leachate considerations and impact to mercury control). The balance of plant impacts have been addressed as part of the S&L cost reports based on typical assumptions, but would also be impacted should the design injection rate vary. Any compliance strategy which were to rely on DSI technology would need to be contingent on successful completion of a demonstration test.

4.2.3 Dry / Semi-Dry Flue Gas Desulfurization

Of the various designs for dry or semi-dry FGD systems, the most popular is the Spray Dryer Absorber (SDA) design. In the SDA design, a fine mist of lime slurry is sprayed into an absorption tower 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 heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower, resulting in the formation of a dry powder that is carried out with the gas and collected with a fabric filter.

SDA systems can achieve control efficiencies ranging from 60 to 95 percent.[16] SDA is a technically feasible option for control of SO_2 from Unit 1 and Unit 2. Based on a site-specific study completed by S&L, SDA could technically achieve an SO_2 emission rate of 0.06 lb/MMBtu at Unit 1 and Unit 2.

4.2.4 Wet Flue Gas Desulfurization

While WFGD is technically feasible, it is not expected to achieve significant reductions beyond DFGD/SDA and was eliminated in the previous analyses and in EPA's final regulations (SIP approval and FIP). Accordingly, WFGD is not considered further in this analysis.

4.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS FOR UNIT 1 AND UNIT 2

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing SO_2.
Table 4-2Table 4-2 provides a ranking of the control levels for the controls listed in the previous section.

Table 4-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies

Control Technology	Achievable Emission Rate (lb/MMBtu) [A]
Semi-Dry Scrubber (SDA)	0.06
Enhanced DSI	0.15
DSI	0.35
Low Sulfur Coal	0.6

4.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

The fourth step in the BART analysis is the impact analysis, which evaluates the impacts for the control options deemed feasible in Step 2. This analysis typically is conducted to demonstrate that the most effective control technology does not necessarily constitute BART. The BART guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The RUL of the source

Because the RUL of the source directly affects the cost of compliance, RUL is considered first.

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

4.4.1 Remaining Useful Life

[redacted]

4.4.2 Cost of Compliance

The capital costs and annual operating and maintenance costs for the considered control options, except for the LSC option, were developed by S&L and are included in Appendix A. The annual cost increase due to burning only LSC is based on a cost premium of $0.50 per ton, which was the premium provided to EAI's fuel purchasing department by its coal suppliers. For the S&L-developed costs, two sets of values are presented. The first, in Table 4-3, is the actual cost estimated for each unit and control option. The second, in Table 4-4Table 4-4, is the estimated cost after excluding cost items that EPA has historically claimed should not be accounted for in BART cost effectiveness calculations. An example of an excluded cost is Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a FGD installation, which can take several years to complete (≥ 5 years). Although interest expenses will certainly be incurred on such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of AFUDC and certain other costs. EAI disagrees and believes that determining the cost effectiveness of the control options must realistically reflect the actual cost of compliance. *See* EAI's comments on the proposed FIP.[17] Nonetheless, for completeness, this analysis shows a range of cost effectiveness both including AFUDC and other costs and excluding those costs.

[redacted]

Trinity determined the values for annual tons of SO_2 reduced by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate was based on the average rate for the 2009-2013 baseline period.[19] The controlled annual emission rates were based on the lb/MMBtu levels listed in Table 4-2 multiplied by the future annual heat input, which was based on the average actual heat input from CAMD for the 2009-2013 baseline period. For the LSC scenario, "controlled" annual emission rates were based on an 8.75 percent decrease compared to baseline annual emission rates, which is estimated by comparing the maximum 30-boiler operating day rolling average to the controlled emission rate of 0.6 lb/MMBtu.

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 4-3 presents a summary of the cost effectiveness for each control

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[17] Entergy Arkansas Inc. "Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas" (EPA Docket ID No. EPA-R06-OAR-2015-0189), August 7, 2015, pp. 10-11.

[18] October 27, 2021 per 81 Fed. Reg. Vol. 81, p. 66416. However, given that actual installation would take at least five years, SDA likely could not be installed until 2023 or later.

[19] As noted above, this is a conservative baseline, and EAI would have been justified in using a more recent baseline with lower emissions that would have resulted in generally higher cost effectiveness values.

option. The cost of switching to low sulfur coal is [redacted]. [redacted]. It's noted (without waiver) that the cost effectiveness of add-on controls even when excluding certain costs for which EPA has expressed concern (e.g., AFUDC), but that will be incurred as explained above, [redacted][20]

Table 4-3. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Actual Costs

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	[redacted]	[redacted]	[redacted]	[redacted]	8,900
SN-02 – DSI	16,034	9,807	[redacted]	[redacted]	[redacted]	[redacted]	8,807
SN-01 – Enhanced DSI	15,939	4,187	[redacted]	[redacted]	[redacted]	[redacted]	8,209
SN-02 – Enhanced DSI	16,034	4,203	[redacted]	[redacted]	[redacted]	[redacted]	8,153
SN-01 – SDA	15,939	1,675	[redacted]	[redacted]	[redacted]	[redacted]	7,771
SN-02 – SDA	16,034	1,681	[redacted]	[redacted]	[redacted]	[redacted]	7,722

Table 4-4. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Costs Adjusted for EPA-Exclusions for Illustration Purposes

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	[redacted]	[redacted]	[redacted]	[redacted]	7,764
SN-02 – DSI	16,034	9,807	[redacted]	[redacted]	[redacted]	[redacted]	7,683
SN-01 – Enhanced DSI	15,939	4,187	[redacted]	[redacted]	[redacted]	[redacted]	7,137
SN-02 – Enhanced DSI	16,034	4,203	[redacted]	[redacted]	[redacted]	[redacted]	7,088
SN-01 – SDA	15,939	1,675	[redacted]	[redacted]	[redacted]	[redacted]	5,883
SN-02 – SDA	16,034	1,681	[redacted]	[redacted]	[redacted]	[redacted]	5,846

[20] Issues raised on appeal of the federal plan include EPA's use of undervalued cost of controls. However, without waiver of any claims or arguments, EPA's estimates also support the conclusion that SDA is not cost effective. Using EPA's estimates of capital cost [redacted] and emissions reductions (14,363 tpy for Unit 1 and 15,221 tpy for Unit 2), [redacted]

4.4.3 Energy Impacts and Non-Air Quality Impacts

There are numerous energy impacts and adverse non-air quality environmental impacts associated with the add-on controls under consideration. Some examples related to the use of DSI include (a) the need for substantial storage and transportation – both delivery via rail and conveyance on site – of Trona, (b) the forced abandonment of the beneficial re-use of fly ash, and (c) potential negative impacts on the PM control device.[21] These impacts are more fully addressed for all the considered control options in the S&L reports included in Appendix A.

4.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

Trinity conducted an impact analysis to assess the visibility improvement achieved. The impact analysis compared the impacts associated with the baseline emission rates to the impacts associated with the maximum emission rates representative of each control option.

Table 4-5 summarizes the lb/hr emission rates that were modeled to reflect each control option. The NO_X and total PM_{10} emission rates were modeled at the revised 2009-2013 baseline rates. The applicable NPS speciation spreadsheets were relied upon to determine emission rates for PM species.[22,23,24] SO_4 emission rates were independently calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[25]

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[21] Sargent & Lundy, *Entergy Arkansas, Inc. White Bluff DSI Cost Estimate Basis Document*, SL-014000 Final, Rev. 0, August 3, 2017, pp. 6-10. *See* Appendix A of this report.

[22] Low sulfur coal PM speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[23] DSI and Enhanced DSI PM speciations are based on the NPS workbooks for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with an ESP or Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[24] DFGD speciation is based on the NPS workbook for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with a Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[25] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 4-5. Emission Rates Modeled to Reflect SO_2 Controls for Unit 1 and Unit 2

Unit & Control Option	SO_2 (lb/hr)	SO_4 [A] (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	EC (lb/hr)	SOA (lb/hr)	Total PM_{10} (lb/hr)
SN-01 – LSC	5,370.0	4.0	3,355.4	40.4	31.1	1.2	9.3	119.2
SN-02 – LSC	5,370.0	4.0	3,590.5	40.4	31.1	1.2	9.3	119.2
SN-01 – DSI	3,132.5	0.5	3,355.4	29.0	22.4	0.9	13.4	119.2
SN-02 – DSI	3,132.5	0.5	3,590.5	29.0	22.4	0.9	13.4	119.2
SN-01 – Enhanced DSI	1,342.5	0.02	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – Enhanced DSI	1,342.5	0.02	3,590.5	13.4	12.9	0.5	18.5	119.2
SN-01 – SDA	537.0	0.01	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – SDA	537.0	0.01	3,590.5	13.4	12.9	0.5	18.5	119.2

[A] SO_4 as it is displayed in this table represents ammonium sulfate.

Comparisons of the existing/baseline visibility impacts and the post-control visibility impacts are provided in Table 4-6 and Table 4-7.

Table 4-6. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 1 (Across All Modeled Years, 2001-2003)

	CACR		UBPU		HERC		MING	
Scenario	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Baseline	1.505	99	1.051	69	0.925	49	0.802	51
LSC	1.376	89	0.908	54	0.758	34	0.687	40
Improvement over baseline	*0.129*	*10*	*0.143*	*15*	*0.167*	*15*	*0.115*	*11*
DSI	1.197	64	0.676	30	0.584	19	0.469	17
Improvement over baseline	*0.308*	*35*	*0.375*	*39*	*0.341*	*30*	*0.333*	*34*
Improvement over LSC	*0.179*	*25*	*0.232*	*24*	*0.174*	*15*	*0.218*	*23*
Enhanced DSI	1.013	41	0.496	14	0.458	11	0.366	6
Improvement over baseline	*0.492*	*58*	*0.555*	*55*	*0.467*	*38*	*0.436*	*45*
Improvement over LSC	*0.363*	*48*	*0.412*	*40*	*0.300*	*23*	*0.321*	*34*
Improvement over DSI	*0.184*	*23*	*0.180*	*16*	*0.126*	*8*	*0.103*	*11*
SDA	0.902	35	0.409	7	0.400	6	0.298	2
Improvement over baseline	*0.603*	*64*	*0.642*	*62*	*0.525*	*43*	*0.504*	*49*
Improvement over LSC	*0.474*	*54*	*0.499*	*47*	*0.358*	*28*	*0.389*	*38*
Improvement over DSI	*0.295*	*29*	*0.267*	*23*	*0.184*	*13*	*0.171*	*15*
Improvement over Enhanced DSI	*0.111*	*6*	*0.087*	*7*	*0.058*	*5*	*0.068*	*4*

Table 4-7. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 2 (Across All Modeled Years, 2001-2003)

	CACR		UBPU		HERC		MING	
Scenario	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**	**98% Impact (Δdv)**	**# Days > 0.5 Δdv**
Baseline	1.533	100	1.059	71	0.912	52	0.819	49
LSC	1.436	89	0.932	55	0.775	35	0.697	41
Improvement over baseline	*0.097*	*11*	*0.127*	*16*	*0.137*	*17*	*0.122*	*8*
DSI	1.259	66	0.700	31	0.609	19	0.486	18
Improvement over baseline	*0.274*	*34*	*0.359*	*40*	*0.303*	*33*	*0.333*	*31*
Improvement over LSC	*0.177*	*23*	*0.232*	*24*	*0.166*	*16*	*0.211*	*23*
Enhanced DSI	1.073	42	0.528	17	0.483	12	0.384	7
Improvement over baseline	*0.460*	*58*	*0.531*	*54*	*0.429*	*40*	*0.435*	*42*
Improvement over LSC	*0.363*	*47*	*0.404*	*38*	*0.292*	*23*	*0.313*	*34*
Improvement over DSI	*0.186*	*24*	*0.172*	*14*	*0.126*	*7*	*0.102*	*11*
SDA	0.959	37	0.427	12	0.426	8	0.318	3
Improvement over baseline	*0.574*	*63*	*0.632*	*59*	*0.486*	*44*	*0.501*	*46*
Improvement over LSC	*0.477*	*52*	*0.505*	*43*	*0.349*	*27*	*0.379*	*38*
Improvement over DSI	*0.300*	*29*	*0.273*	*19*	*0.183*	*11*	*0.168*	*15*
Improvement over Enhanced DSI	*0.114*	*5*	*0.101*	*5*	*0.057*	*4*	*0.066*	*4*

4.6 BART FOR SO_2 FOR UNIT 1 AND UNIT 2

Based on the costs of the control options listed above, BART for Unit 1 and Unit 2, when considering the updated RUL, would be an emission level of 0.6 lb/MMBtu based on the use of low-sulfur coal.

APPENDIX A. CONTROL COST INFORMATION

SO_2 CONTROL COST INFORMATION – LAST UPDATED AUGUST 2017

Table B-8. Baseline Visibility Impairment Attributable to Unit 1 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.912	1.505	38	74.33	25.34	0.17	0.15
2002	2.048	1.306	29	61.53	34.59	0.83	3.04
2003	4.020	1.053	32	47.92	50.35	0.35	1.39
Upper Buffalo							
2001	2.089	1.051	30	68.58	31.17	0.26	0.00
2002	1.438	0.742	15	79.11	20.19	0.37	0.32
2003	1.773	1.033	24	79.79	19.92	0.28	0.00
Hercules Glades							
2001	1.643	0.925	24	90.21	9.56	0.23	0.00
2002	1.184	0.567	10	74.20	25.45	0.25	0.10
2003	1.977	0.704	15	86.02	13.73	0.25	0.00
Mingo							
2001	1.538	0.802	16	51.46	48.03	0.39	0.12
2002	0.898	0.708	21	54.87	44.82	0.31	0.01
2003	1.003	0.666	14	57.31	41.18	0.41	1.11

Table B-9. Baseline Visibility Impairment Attributable to Unit 2 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.994	1.533	39	36.23	60.75	0.74	2.28
2002	2.098	1.322	29	59.43	36.53	0.82	3.22
2003	4.084	1.059	32	96.37	3.38	0.24	0.01
Upper Buffalo							
2001	2.066	1.059	30	66.54	33.21	0.26	0.00
2002	1.447	0.739	16	77.57	21.71	0.37	0.35
2003	1.791	1.030	25	78.24	21.46	0.28	0.00
Hercules Glades							
2001	1.665	0.912	25	89.39	10.38	0.23	0.00
2002	1.185	0.568	11	72.38	27.26	0.25	0.11
2003	1.947	0.720	16	40.35	58.44	0.40	0.82
Mingo							
2001	1.580	0.819	15	81.62	17.93	0.33	0.12
2002	0.886	0.719	20	58.93	40.66	0.19	0.22
2003	0.999	0.678	14	55.08	43.36	0.40	1.17

APPENDIX C. REFINED PM SPECIATION CALCULATIONS

ENTERGY ARKANSAS, INC.

WHITE BLUFF DRY FGD

COST ESTIMATE AND TECHNICAL BASIS

SL-012831
Final, Rev. 1
August 3, 2017
Project 13027-002

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

CONTENTS

EXECUTIVE SUMMARY

The purpose of this study is to estimate the total capital investment and operating and maintenance (O&M) costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2 using an Engineer, Procure, Construct (EPC) contracting strategy. A preliminary conceptual design was developed for implementation of dry FGD technology at the White Bluff station to serve as the technical basis of the capital and O&M estimates.

The capital cost estimate includes the following components which comprise the total cost the Owner will incur to install dry FGD technology at White Bluff:

- FGD Island Cost supplied by a Dry FGD System Supplier including the main process equipment
- Balance of Plant Cost including auxiliary equipment and systems, foundations and buildings, site work, demolition and relocation
- Other Direct and Construction Indirect Costs including labor premiums, freight, contractor's G&A and profit
- Indirect Costs including engineering, startup spare parts, technical field advisors, and the additional fee associated with an EPC contracting strategy
- Escalation and Interest During Construction associated with the project duration for implementation of a large air quality control technology
- Owner's Costs including internal labor, insurance, and initial lime reagent fill
- Third Party Services including construction management oversight, start-up and commissioning oversight, Owner's Engineer services, and performance testing
- Project Contingency to cover unknown and undefined scope associated with the project which would result in additional cost to the Owner

The total capital investment to install dry FGD on White Bluff Units 1 and 2 was estimated to be $991,489,000. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%. In addition, the O&M costs were estimated to be approximately $8,132,000 per year per unit and include the cost of lime (reagent), byproduct disposal, auxiliary power, water, replacement bags and cages, maintenance costs, and operating labor.

1. PURPOSE

The purpose of this study is to estimate the total capital investment and operating and maintenance costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2. This report documents the conceptual design and technical basis for the dry FGD cost estimate.

2. APPROACH

2.1 TECHNOLOGY SELECTION

Sargent & Lundy (S&L) previously performed an evaluation of wet and dry FGD technology for Entergy's White Bluff Station. The evaluation included development of a preliminary conceptual design for both wet and dry FGD systems at the White Bluff station. The preliminary designs were used as the basis of an evaluation which compared the overall economics of each system, including capital and operating costs. The study concluded that a dry FGD system had an economic advantage over wet FGD when the design coal sulfur is below 3 lb SO_2/MMBtu. Based on the current market and potential future regulations, dry FGD technology would have an economic advantage over wet FGD for SO_2 reduction at the White Bluff station.

2.2 CONTRACTING APPROACH

Many utilities elect to utilize a one contract engineer-procure-construct (EPC) approach for major retrofit projects, such as large FGD projects. The EPC approach allows the Owner to contract with one entity which then manages the overall project. The EPC Contractor procures the material, equipment and services needed to complete the project and the EPC Contractor takes full responsibility for the equipment and work supplied by each of its subcontractors.

With this approach the Owner takes on less risk in the overall management and coordination of the project. However, shifting this risk to the EPC Contractor increases the total price for the EPC contract; "Whilst there are… numerous advantages to using an EPC contract, there are some disadvantages. These include the fact that it can result in a higher contract price than alternative contractual structures. This higher price is a result of a number of factors not least of which is the allocation of almost all the construction risk to the contractor."[1] The additional cost due to an EPC contracting approach is represented in our cost estimate as an EPC Risk Fee.

The Owner's control over design details of the system is limited, using this contracting strategy, to the requirements specified in the contract. This results in an additional upfront effort for the Owner and the Owner's Engineer to thoroughly define the project in the specification. Whatever is not defined will be excluded from the EPC Contractor's scope resulting in potential change orders. The Owner and Owner's Engineer are also responsible for reviewing the EPC Contractor's submitted design drawings and schedules to ensure what has been agreed upon in the final contract is included.

2.3 CAPITAL COST DEVELOPMENT

The capital cost estimate is based on project-specific information, including:

- A preliminary conceptual design developed for implementation of dry FGD technology at the White Bluff station.
- An engineer-procure-construct (EPC) contracting strategy.
- A Dry FGD System Supplier, subcontracted by the EPC Contractor, providing the main process equipment as a complete FGD Island.
- The FGD Island equipment and installation cost is based on a budgetary proposal received from Alstom in September 2013. The budgetary proposal is based on installing SDA technology on both of the White Bluff units.

The capital cost estimate includes the following components which comprise the total price of the EPC Contract to complete the work:

- Equipment and material
- Installation labor
- Demolition and Relocation work
- Indirect field costs and BOP engineering
- Freight on Materials
- General and Administration
- Erection contractor profit

[1] "EPC Contracts in the Power Sector", prepared by DLA Piper, 2011, page 6. See: https://www.dlapiper.com/

- Engineering, Procurement and Project Services
- Spare parts
- EPC Fee
- Escalation

The equipment design basis is summarized in Section 3 of this report and the scope of the estimate is summarized in Section 4. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%. The costs provided in this report are in 2015 dollars.

In order to estimate the *total plant* capital cost for installation of FGD at White Bluff, the following costs which would be incurred outside of the scope of the EPC contract were included:

- Owner's Costs
- Third Party Services – Construction Management Oversight
- Third Party Services – Startup and Commissioning Oversight
- Third Party Services – Owner's Engineer
- Third Party Services – Performance Testing
- Project Contingency
- Interest During Construction or Allowance for Funds Used During Construction

The cash flow provided in Attachment 2 is based on a monthly progress payment schedule developed using the preliminary execution schedule included in Attachment 3. Specific details regarding the milestones making up the payment schedule are listed in Attachment 4. Below is a summary of those activities that represent major or large payment milestones based on a project start date of January 2015.

Month	Date	Milestone
1	February 2017	Award EPC Contract Execution
5	June 2017	EPC Contractor Procures Major Equipment
7	August 2017	EPC Contractor Procures Major Equipment
10	November 2017	Flue Gas Ductwork Procurement Initiated by EPC Contractor
13	February 2018	SDA and Fabric Filter Design Drawings
15	April 2018	Award Fabric Filter Bags and Cages Flue Gas Ductwork Start of Fabrication

Month	Date	Milestone
17	June 2018	Physical Flow Model Completed
19	August 2018	Mobilize On-Site
20-38	September 2018 to March 2020	Construction Activities
41	June 2020	Unit 1 Substantial Completion
45	October 2020	Unit 2 Substantial Completion
		Demobilization Complete
46	November 2020	Unit 1 Final Acceptance
47	December 2020	Unit 2 Final Acceptance

Each monthly cash outlay in the cash flow is broken down by category (labor, equipment and materials, and indirect costs).

3. DRY FGD CONCEPTUAL DESIGN AND SYSTEM COMPONENTS

A conceptual design for the implementation of Dry FGD at the White Bluff station was developed by Sargent & Lundy LLC (S&L) as a precursor to the development of the cost estimate. A general arrangement drawing showing the conceptual design is included in Attachment 7. The dry FGD conceptual design was developed for each of the following subsystems:

3.1 DRY FGD ISLAND

3.1.1 Reagent Preparation System

Lime will be supplied to the lime day bins from the long-term storage silo located in the Reagent Handling Area and supplied by the EPC Contractor. The lime day bins, located in the Reagent Preparation Area and provided by the Dry FGD System Supplier, will each have a storage capacity to supply the plant with lime reagent for 24 hours when firing 1.2 lb SO_2/mmBtu coal.

Lime from the day bin will be gravity-fed through feeders to a lime slaker, where the lime will be slaked (mixed with low pressure service water and converted from calcium oxide to calcium hydroxide slurry). The plant will have a total of two lime slaking trains (2 x 100%), each sized to process enough lime slurry to supply the entire plant. Each lime slaker will discharge to a lime slurry transfer tank, which is equipped with two lime slurry transfer pumps which will feed into the lime slurry storage tanks. The common lime slurry storage tanks will each be sized for 12 hours of storage for the entire plant when burning a 1.2 lb SO_2/mmBtu coal. The lime day bin, slaking trains, and lime slurry tanks are sized to provide the necessary reagent slurry to both units simultaneously. The lime slurry tanks are built with cross-ties such that either slurry tank can feed either the Unit 1 or Unit 2 FGD systems.

A total of four lime slurry feed pumps (two per unit), each sized for 100% flow to one unit, will pump the lime slurry from the storage tanks to the SDAs through one of 2 x 100% piping loops, and return unused slurry back to the lime slurry storage tank. The closed-loop reagent supply line requires a flow velocity between 4-10 fps to avoid any solids buildup in the piping. Because of this, the pumping requirement is higher than the actual SDA requirement and must be sufficiently greater than the slurry flow that is pumped into the absorbers to allow the returning flow to remain above 4 fps.

3.1.2 Absorbers

Three absorbers, each treating 33⅓% of the flue gas are provided for each unit. Depending on the supplier and the type of atomizer normally used, there may be one rotary atomizer per absorber with a shared spare (B&W), three rotary atomizers per absorber with one or more shared spares (Alstom, basis of the estimate), or multiple dual-fluid atomizers with 15% shared spares (Siemens). The cost estimate includes contingency to capture the possibility of any of these designs.

3.1.3 Baghouse

Each SDA will be paired with a pulse-jet baghouse with a gross air-to-cloth ratio of approximately 3.2-3.4 ft/min. The filter bags in each baghouse are cleaned by pulses of compressed air. The air compressors will be 4 x 33% for the station and are included in the scope of the baghouse supplier.

3.1.4 Byproduct Recycle System

The reaction byproducts from the absorbers will be collected in the baghouses and a portion of the collected material will be recycled. The baghouse hoppers will be emptied through air lock feeders and pneumatically conveyed to two recycle day bins located in the Byproduct Recycle Area and supplied by the Dry FGD System Supplier, which are common for both units. The air-lock feeders are installed without a spare. One recycle day bin is located in the recycle train for each unit. The common byproduct recycle day bins (one per unit) provide 8-hours of storage when burning 1.2 lb SO_2/mmBtu coal.

Each byproduct recycle day bin is equipped with two recycle slurry preparation systems. The byproduct in each recycle day bin is gravimetrically conveyed to one of two systems where the byproduct is slurried with water (cooling tower blowdown). The byproduct recycle slurry is stored in one of four plant wide recycle slurry tanks, two per unit (combined 4-hour storage capacity).

Two recycle water make-up tanks are located in the recycle area with a capacity of 250,000 gallons (to be supplied by the EPC Contractor). The recycled by-product slurry will be combined with fresh lime slurry for feed to the SDA atomizers. Recycle feed slurry pumps (4 x 100%, two installed per unit) will be used to transfer the recycle slurry from the recycle slurry tanks to the atomizers. In addition, all recycle feed lines are provided in a loop configuration as with the reagent system, with a complete redundant loop to allow unhindered operation due to any pluggage of pumps or feed piping.

3.2 REAGENT HANDLING SYSTEM

As part of the conceptual design, several lime delivery methods were evaluated and it was determined that rail delivery provided the best alternative for White Bluff based on ease of implementation, overall plant interface, and lowest evaluated cost (in terms of required capital investment and delivered cost of lime). Therefore, the basis of the estimate is delivery of lime via hopper-bottom railcars with truck unloading as a backup. In order to accommodate rail delivery to the site, a new rail spur will be constructed from the existing track bordering the west side of the plant. Lime trains will enter and exit the station from this spur. A trackmobile car positioner will position railcars, two at a time, in the enclosed delivery shed for unloading. The cost estimate includes the capital cost associated with railcar unloading, including the new rail spur and the renovation of the existing rail spur to handle lime delivery. A vacuum pneumatic system will unload the railcars into either of the two (2) lime storage silos. The lime storage silos will be sized for supply of reagent for 14 days of storage at full load when firing 1.2 lb SO2/mmBtu coal. Lime from the long-term storage silos will be pneumatically transferred to two lime day bins located in the Reagent Preparation Area and supplied by the Dry FGD System Supplier.

3.3 BYPRODUCT HANDLING SYSTEM

Excess FGD byproduct from the recycle system will be pneumatically conveyed to either of the two common long- term FGD byproduct storage silos. The two long-term FGD byproduct storage silos are each sized to handle the byproduct for a total of 7 days of storage when firing the 1.2 lb SO_2/mmBtu coal. The byproduct will be mixed with a small amount of fly ash and water to form a final product which contains approximately 65% FGD byproduct, 5% fly ash, and 30% water. In order to achieve this mixture, a common fly ash blending bin (7-day storage) will be located near the new byproduct silos. The feed rate of fly ash discharged from the blending bin is controlled to maintain the ratio of byproduct to fly ash. A pneumatic airslide conveyor will discharge fly ash directly into an unloading conditioner, simultaneously mixing fly ash with the proper ratios of water and FGD byproduct (discharged from the silo). The wetted byproduct/fly ash mixture is then loading into dump trucks, which will deposit the FGD byproduct in a final storage location in the landfill. A bulldozer will maintain the landfill pile. The capital cost for the silos, conveying system and byproduct/fly ash blending system is included in the cost estimate. As part of the conceptual design, the existing landfill was evaluated and was determined to have sufficient capacity to accommodate the addition of FGD byproduct. Therefore no costs were included in the capital estimate for the (existing) landfill. In addition, it was assumed that the existing haul trucks would be used to transport the FGD byproduct.

3.4 FLUE GAS HANDLING SYSTEM

The flue gas from the existing ID fans will be ducted to the absorbers. The gases from the absorbers will be ducted to the baghouses to collect the reaction by-products and residual fly ash. Two axial booster fans (2 x 50% for each unit) will be located downstream of the absorbers and baghouse; the booster ID fans can be provided by the Dry FGD System Supplier or the EPC Contractor. Due to the dry condition of the scrubbed flue gas, the existing stack and liners will be used for the retrofit case.

The existing chimney and carbon steel liners were evaluated as part of the conceptual design and were deemed to be suitable for a dry FGD application. In addition, the top 50 feet of the existing chimney liners are constructed of 316 stainless steel so an acid resistant coating on the liner is not required. However, downwash may result in acid attack and discoloration on the outer concrete shell of the chimney; it was determined that an acid resistant coating to the top 100 feet of the concrete shell is recommended; therefore, the cost estimate includes the coating of the top 100 feet of the chimney's outer concrete shell.

3.5 ELECTRICAL BOP SYSTEM

The existing auxiliary power system was evaluated as part of the conceptual design for the White Bluff dry FGD system. In order to feed the new dry FGD and other BOP equipment, significant modifications and additions to the existing power system are required. These include installation of new auxiliary transformers, medium- and low-voltage switchgear buses, motor control centers (MCCs) and upgrades to the isolated phase tap-off buses.

3.6 I&C BOP SYSTEM

As part of the conceptual design, the existing control system was evaluated to determine the required modifications necessary to implement dry FGD technology at the White Bluff station. The dry FGD system will be controlled using a new Foxboro I/A system which will integrate with the existing power block Foxboro I/A system. The control processors, I/O cabinets, and other system components will be located in the new electrical equipment building (EEB) for each unit. Two HMIs will be installed in the new EEB for each unit to provide any local controls for the lime preparation and byproduct recycle systems provided by the Dry FGD System Supplier. The baghouse will be controlled through the Allen-Bradley ControlLogix PLC and the ID booster fans will be controlled through the existing Foxboro I/A system controller(s), which are used to control boiler air and furnace pressure.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

The following summarizes the design inputs used as the basis for the White Bluff dry FGD Systems:

- Design SO_2 inlet concentration of 1.2 lb SO_2/MMBtu for equipment design, based on the current coal contract sulfur limit.
- SO_2 inlet concentration of 0.57 lb SO_2/MMBtu for annual operating costs, based on the annual heat input weighted average emission from 2009 through 2013.
- Design SO_2 outlet concentration of 0.06 lb SO_2/MMBtu.
- Annual capacity factor of 72.1% (annual average capacity factor for White Bluff Units 1 and 2 based on historical heat input from 2009 through 2013).
- Compliance deadline of December 2020, based on a project start date of January 2015.

4.1 EPC CONTRACT PRICE

The Dry FGD System Supplier will provide all of the equipment within the FGD Island. The FGD Island will include the Reagent Preparation Equipment, Absorber Area Equipment, Baghouse Area Equipment and the Byproduct Recycle Equipment. The booster ID fans could be provided by either the Dry FGD System Supplier or the EPC Contractor; the basis of this estimate is supply of the booster fans by the Dry FGD System Supplier. The EPC Contractor will provide the remaining BOP scope in order to provide a complete and operable FGD system. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DFGD supplier.

The scope of work for the cost estimate is broken out by area below:

1. <u>Dry FGD Island</u>
   a. Reagent Preparation System, common to both units:
      - Two lime day bins, 24-hours storage each
      - Two detention lime slakers at 100% capacity, each with a grit screen, gravimetric feeder
      - Two lime slurry transfer tanks
      - Four slurry transfer centrifugal pumps
      - Two lime slurry storage tanks
      - Four slurry feed centrifugal pumps

- Cost estimate based on budgetary proposal from Alstom; the budgetary proposal is based on a design sulfur of 2.0 lb/MMBtu, cost adjustments were included in the estimate for a lower design sulfur of 1.2 lb/MMBtu. These cost adjustments were developed by estimating the differential equipment cost for the reagent preparation and waste handling equipment. The impacted equipment is identified in Section 4.5 which discusses the sulfur design basis sensitivity.

b. Absorber Area, per unit
- Three absorber vessels per unit, with access doors
- Rotary atomizers, two spare atomizers included
- Vessel material carbon steel, ¼ in. – ⅝ in. carbon steel
- Heating and ventilation
- Vacuum piping
- SDA Superstructure
- Cost estimate based on budgetary proposal from Alstom

c. Baghouse Area, per unit
- New baghouse, including pulse jet cleaning system and all appurtenances
- Cost estimate based on budgetary proposal from Alstom

d. Byproduct Recycle System, per unit (located remotely in common location for both units)
- One recycle silo with bin vent filter per unit, 8-hour total capacity
- Two recycle mix tanks per unit
- Two recycle slurry tanks per unit, with two recycle slurry centrifugal pumps per unit
- Agitators for each tank
- Baghouse ash handling system common to both units
- Rotary air-lock valves from baghouse hopper outlets to pressure pneumatic conveying system (60-degree typical)
- Pneumatic pressure blowers (8 x 33⅓ %)
- Cost estimate based on budgetary proposal from Alstom

e. ID Booster Fans, per unit
- Two approximately 5,200 hp axial booster fans per unit sized to overcome pressure drop associated with FGD and baghouse
- Includes motors - no spare motor included
- Cost estimate based on budgetary proposal from Alstom
- Dampers from ID fan to booster fans (cost estimated separately, not included in Alstom budgetary proposal)

f. Interconnecting Ductwork, per unit
   - ID fan outlet to absorber inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm
   - Absorber outlet to baghouse inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm
   - Baghouse outlet to new booster fans and fan outlet to the stack inlet ductwork and supports; carbon steel, ¼ in, design velocity, 3,600 fpm

2. <u>FGD Island Foundations and Enclosures</u>

   a. Absorber tower foundations including caissons

   b. Baghouse area foundations including 18” auger cast piles 60’ long

   c. Booster fan area foundations

   d. 6” insulation with lagging for Absorbers and Baghouses (cost estimated separately, not included in Alstom budgetary proposal)

   e. Penthouse enclosure for Absorbers located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)

   f. Two elevators (one for each unit) to provide maintenance access to Absorber and Baghouse Areas

   g. Enclosure around hoppers for Baghouses located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)

   h. Lime preparation building for Reagent Preparation Area in FGD Island, 50’ x 50’ x 50’, including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

   i. Byproduct recycle building for Byproduct Recycle Area in FGD Island, 60’ x 60’ x 60’, including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

3. <u>Reagent Storage and Handling, common to both units:</u>

   a. Lime rail car unloader:
      - Lime delivery via 25-car unit train
      - System consists of mobile receiving pan and associated vacuum pneumatic equipment to unload railcar through railcar bottom hoppers
      - Enclosed railcar unloading building
      - One vacuum pneumatic system operating to unload a car
      - Pneumatic vacuum exhausters (2 x 100%)
      - Filter separator with vacuum-to-pressure transfer hopper and valves
      - One lot of pneumatic conveying piping located on an above-grade sleeper pipe rack

- Cost estimate based on vendor quote from United Conveyor Corporation (UCC) for a similar unit

b. Lime storage silos:
   - Two silos, 14-days storage and capable of storing a train load of lime, 2,400-tons storage total, including substructure and superstructure
   - 32’ diameter and 95’ height to top
   - 1,200-tons storage, each
   - Continuous level detection systems
   - Bin vent filters
   - Live bottom hopper outlets
   - Rotary airlock assemblies
   - Lime transfer systems:
     - Pressure pneumatic conveying system from lime storage silos to lime day bins
     - Pneumatic pressure blowers (3 x 100%)
     - One lot of pneumatic conveying piping located on an elevated pipe rack

c. Concrete foundations including caissons for all material silos

d. Concrete foundations for pneumatic conveying blowers and exhausters

4. Byproduct Handling System, common to both units

   a. Two FGD by-product storage silos (7-day capacity each, common to both units) with bin vent filter, fluidizing system, and two unloading conditioners (one operating, one spare per silo)

   b. One common fly ash blending, 7-day storage bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

   c. Water pumps and associated piping for unloading conditioners (pin mixers) at both silos

   d. Compressed air system for air operated valves

   e. Storage silo substructure and superstructure

   f. Continuous level detection system

   g. One lot pneumatic conveying piping located on an above grade pipe rack

   h. Two truck scales and substructure

   i. Existing road improvements for truck haulage to existing landfill

   j. Cost estimate based on budgetary proposal from UCC for similar project

   k. Concrete foundations including caissons for all material silos

l. Concrete foundations for pneumatic conveying blowers and exhausters

5. Flue Gas Handling BOP, per unit
   a. ID fan outlet to absorber inlet ductwork insulation; 6” with lagging6” insulation with lagging
   b. Absorber outlet to baghouse inlet ductwork insulation; 6” with lagging
   c. Baghouse outlet to new booster fans and fan outlet to the stack inlet ductwork insulation; 6” with lagging
   d. Concrete foundations for all flue gas ductwork
   e. Epoxy trowel coating on top 100 feet of outside of chimney shell

6. Civil BOP
   a. Roadwork
   b. Site grading
   c. Soil removal earthwork
   d. Excavation, backfill, and compaction for all foundations
   e. Storm sewer work
   f. Two-cell pond for wastewater storage of process water/slurry
   g. Laydown Area
      - Development of a new laydown area, approximately 10 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not required land to be purchased.
   h. Highway Intersection Upgrade to provide sufficient plant access for construction period
      - New Bypass Lane on Westside of Highway 365
      - New Southbound Left Turn Lane on Highway 365
      - New Northbound Merge Lane on Highway 365
      - New Northbound Right Turn Lane on Highway 365
      - Extension and upgrade of existing Contractor Haul Road (Highway 46 Spur) to Highway 365
      - Widening of the existing Main Plant Road from the Contractor Haul Road (Highway 46 Spur) to Main Guard House
      - Track crossing signal system at Haul Road (Highway 46 Spur) track crossing
   i. New warehouse building 200’ x 75’ x 15’, including substructure and superstructure.

7. Mechanical BOP System
   a. Interconnecting piping, above-ground and buried
   b. Valves for interconnecting piping, above-ground and buried
   c. Lime slaking water storage tank, 115,000-gallon capacity

d. Slaker water 3” in-line heaters, 475 kW each

e. Recycle make-up water tanks, 2 x 250,000-gallon capacity

f. Pipe Racks, common to both units
- Between lime railcar unloading enclosure and lime silos
- Between lime silos and lime day bins
- From baghouse hoppers to recycle silos and FGD by-product silo
- From lime slurry storage tanks to absorber
- From recycle slurry storage tank to absorber
- Concrete foundations including caissons for all pipe racks
- Shallow concrete foundations for other miscellaneous structures

g. BOP Pumps
- Three by-product recycle water forwarding pumps to recycle slurry, 1000 gpm @ 150’ TDH
- Four reagent prep/recycle sump pumps, 120 gpm @ 150’ TDH
- Two lime silo and unloading area sump pumps, 120 gpm @ 150’ TDH
- Two by-product ash silo area sump pumps, 120 gpm @ 150’ TDH
- Two by-product recycle make-up water tank supply pumps, 2600 gpm @ 200’ TDH
- Two lime slaking water pumps, 750 gpm @ 100’ TDH
- One new Low Pressure Service Water (LPSW) pump, 20,000 gpm @ 100’ TDH, including new intake structure, piping and valves
- Two leachate pumps, 50 hp

h. Instrument Air System, common to both units
- Air compressors; 2 x 100%, 250 scfm each @ 100 psig
- IA dryers w/filters; 2 x 100%, 250 net scfm each
- Air receivers; 2 x 100%
- Instrument air piping to every silo or day bin, bin vent and reagent preparation/recycle area
- Heat-traced piping

i. Service Air System, common to both units
- Air compressors; 2 x 100%
- Air receivers; 2 x 100%

j. Field painting
- Multiple coat system used for exposed ductwork only
- Inorganic zinc primer and polyurethane system used for steel

- Allowance for underground piping shop coatings built into piping cost

8. Demolition and Relocation

   a. Hazardous material accumulation building
   b. Ash handling maintenance building
   c. Drainage ditch
   d. Pipe trench
   e. Fabrication shop
   f. Existing contractor electrical hook up
   g. Existing drainage ditches, rerouted with new concrete trenches
   h. Relocation of ACI injection location from the air heater inlet to upstream of the DFGD
   i. Rail Yard Extension, common to both units
      - Extend rail spur to north to allow lime train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs
   j. Fire Protection System Modifications
      - Deluge system has been included for the new transformers
      - Allowances have been included for fire protection in all of the new buildings; including piping and post indicator valves
      - The new fire protection systems will tie-in to the existing system on-site. It was assumed that the current capacity of the plant fire protections system is sufficient to accommodate the new systems; an evaluation of the current system capacity was not performed.

9. Electrical BOP System

   a. One 115-kV, 1200A isolation disconnect switch
   b. One startup transformer
   c. Two unit auxiliary transformers (UAT)
   d. Three medium-voltage (6.9-kV) switchgear buses (outdoor walk-in type)
   e. Two medium-voltage (6.9-kV) double ended switchgear per unit (total of two)
   f. Two 480-V double ended switchgear buses per unit (total of four)
   g. Six 480-V motor control centers per unit (total of twelve)
   h. Four 6.9-kV/480-V step-down transformers per unit (total of eight)
   i. Two isolated phase UAT tap bus extensions

j. Non-segregated phase bus

k. Medium-voltage cable

l. Low voltage, control and instrumentation cable, as necessary

m. Two electrical equipment buildings

10. Instrumentation and Controls BOP System

a. Controls System based on an estimated number of I/O points:

- Approximately 1,000 I/O points are required for each unit's DFGD system (including reagent preparation), for a total of 2,000 I/O points the cost of which is included in Alstom budgetary proposal pricing.

- Approximately 2,000 I/O points for the common areas at the station, located outside of the DFGD Island.

b. CEMS, per unit

- Existing CEMS analyzers for both units will be recalibrated and recertified; if the existing CEMS analyzers cannot be recalibrated for lower SO_2 emission, new CEMS analyzers will be installed.

11. Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2015 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

12. Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables
b. Premiums and per diems ($10 per hour)
c. Overtime is included based on five 10-hour shifts per week work schedule
d. Freight on construction materials
e. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)
f. Contractor's Profit (included at 5% of total direct and construction indirect costs)

13. EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $23,000,000 without escalation.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of pebble lime was not included in the EPC Contractor's scope, as this is considered to be an operating cost rather than a capital expense. The initial fill of pebble lime is included in the Owner's costs.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 300 man-days. The estimate includes technical field advisors for the FGD system supplier (including FGD system subcontractors) and the DCS supplier.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor (See Section 2.2 for a discussion on the contracting strategy and the EPC Risk Fee). Based on S&L's experience with recent EPC projects, an EPC Risk Fee was included at 10% of the total EPC project costs.

14. Escalation

    Escalation was included in the estimate based on the preliminary execution schedule at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

    For commodities and equipment related to power plant construction, S&L tracks over 200 U.S. indices from major industrial sources such as BLS, Chemical Engineering, Handy Whitman, and Engineering News Records. S&L reviews the various indices in order to develop an overall average and then evaluates the change in the indices over the last three years and the last five years. Based on this analysis, an annual rate of 2.15%/year escalation is projected for commodities and equipment for the time frame for the project.

    S&L uses RS Means as the basis for estimating labor craft rates. In order to project the escalation rate for the estimate, S&L reviewed five major craft labor types typically used in the power plant industry over the last five years using the average cost of craft labor. Based on this information, S&L projected an annual rate of 3.35%/year escalation on labor and indirects.

15. Sales Tax

    Sales Tax is included in the estimate, and was applied at a rate of 8.125% on all material costs.

4.2 OVERALL PROJECT COSTS FOR CAPITAL ESTIMATE

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as Owner's costs, services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs. The following summarizes the additional project costs to Entergy associated with installing dry FGD at the White Bluff Station:

1. Owner's Costs (by Entergy)

   Owner's Costs are direct costs that the Owner incurs over the life of the project. Entergy estimated the cost for the following items which would be real costs Entergy would incur based on the scope and schedule of this project:

   a. Internal Labor – For all major projects, Entergy assigns internal resources to manage the project from initiation through development, contracting, installation, and commissioning. Internal labor includes personnel from several departments including Capital Project Management & Technology, Engineering, Fossil Operations, Legal, Environmental Services, Supply Chain, Risk Management, Finance, Regulatory, and the Operating Company. The internal labor is estimated based on a proposed staffing plan, developed from the project scope and preliminary schedule using average wage rates. Costs are based on the following anticipated staffing levels:

      - Project Development (through EPC Award) – 25 months, equivalent of 10 people

- Project Execution (beginning at EPC Award) – 53 months, equivalent of 22 people

b. Internal Indirects – Indirect costs incurred by Entergy include a payroll allocation, materials and supplies allocation, a depreciation allocation, and capital suspense allocation. The payroll allocation includes payroll overhead costs for items such as employee benefits. The materials and supplies allocation is used to distribute the overhead costs of managing storerooms that are used to procure, track, and issue material and supplies. The depreciation allocation distributes depreciation and amortization expenses for the new assets. Capital suspense is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and A&G (Corporate Accounting) rates.

c. Travel Expenses –Travel expenses are included to support the oversight of the project, including travel for site-visits, monthly status meetings, critical design reviews, etc. Travel expenses are estimated based on projects with similar schedules and scope.

d. Legal Services – Legal services are contracted from external law firms. These services include contract and regulatory compliance support. Entergy estimated the cost of the legal services based on recent EPC projects.

e. Builders Risk Insurance - Builder's Risk Insurance is included in the estimate and covers the materials, equipment, and labor associated with a large scale construction project in case of physical loss or damage. The estimated is based on estimated project value and schedules.

f. Initial Fills - Entergy will procure a supply contract for pebble lime to the station. Under this contract, Entergy will arrange to provide the initial fill of pebble lime to the station for startup, commissioning, and performance testing. A 120 day supply of pebble lime for both units has been included in the estimate based on the reagent pricing identified in Section 4.3.

2. Third Party Services – Construction Management Oversight

The construction management support was estimated based on the proposed staffing plan shown below, developed from the overall project scope and the preliminary schedule. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. The cost of labor is based on present day cost, without escalation. Travel and living expenses are based on the current per diem rate for the White Bluff area of $129/day. Costs are based on the following anticipated staffing levels:

a. Home Office Support – 15 months, 1 person

b. On-Site Construction Manager – 35 months, 1 person

c. On-Site Construction Admin/Project Controls Engineer – 35 months, 1 person

d. Construction Field Engineers – 31.5 months, 2 people

The total cost of the Construction Management Support was estimated to be $4,969,000 without escalation.

3. Third Party Services – Startup and Commissioning Oversight

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. Costs are based on the following anticipated staffing levels:

a. Commissioning Support Specialists – 8 months, 2 people

The total cost of the startup and commissioning support was estimated to be $550,000 without escalation.

4. Third Party Services – Owner's Engineer

The Owner's Engineer cost includes scope as summarized below and was estimated based on the preliminary project schedule, including assumptions on manpower requirements, as well as a comparison cost to other projects with similar scope.

The cost of labor is based on present day cost, without escalation. Costs are based on the following scope for the Owner's Engineer work:

a. Conceptual Study Support
b. EPC Specification Supporting Documents
c. Project Schedule Development
d. EPC Specification Development
e. EPC Bid Evaluation and Contract Conformance
f. General Project Support
   - Monthly Project Status Meetings
   - Weekly Teleconferences
   - Overall Coordination
   - Project Administration
   - Site Visits and Travel
g. Permitting (Construction Permits and Modification to Title V and Solid Waste Permits)
h. Design Review of Drawing Submittals
i. Technical support during design, fabrication, construction, commissioning, and testing
j. Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $6,750,000 without escalation.

5. Third Party Services – Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

a. Development of the test protocol

b. Procuring the services of the testing contractor

c. Overseeing the performance test campaign

d. Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days for each unit.

The total cost of the Performance Testing was estimated to be $275,000 without escalation.

6. Project Contingency

Project contingency is included in the estimate to cover the uncertainty associated with the project costs, and was developed utilizing Entergy's procedure for developing a project's contingency. The process includes developing three components of contingency:

a. Risk Contingency: This category of contingency is developed with the use of a Risk Register that is used to identify risks that may impact the project. Each risk in the Risk Register is analyzed to determine the probability of the risk and the impacts of the risk to the project.

b. Estimate Uncertainty: This category of contingency uses the estimate accuracy classifications to develop an appropriate level of contingency. Entergy has adopted expected accuracy ranges for estimates with upper and lower boundaries for each class of costs estimate. These ranges recognize the uncertainty that exists in the technical engineering and project management deliverables that define scope.

c. Unknown/Emergent Risks: This category of contingency is used to account for any issues that arise during the project that are not contained within the risk register or to cover any costs associated with unanticipated changes in project scope.

A cost qualitative risk assessment (QRA) was performed using Palisade Corporation's @RISK software. QRAs are used to validate the reasonableness of cost estimates, provide confidence for cost projections, and help establish a reasonable level of contingency based on risk-weighted estimates and project risk profiles. The QRA identifies various confidence levels that the contingency amount is sufficient for the project. For this estimate's cost QRA, an 80% confidence level was selected which means the project is 80% likely to be completed at or below the calculated value. The 80% confidence level results in a contingency value of 15% of the total project cost before escalation and IDC. This level of contingency is within Entergy's guidelines for target contingency range for this class of estimate. The contingency estimate is included in Attachment 8.

7. Escalation on Owner's Costs

Escalation was included in the estimate at an escalation rate 3.35% on the Owner's costs. This escalation rate is based on the rate developed by S&L for labor and indirects above.

8. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on the milestone payment schedule included in Attachment 4 and a typical interest rate of 7.0% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable Operating and Maintenance (O&M) costs. All of these values, with the exception of the reagent costs, were provided by Entergy and are consistent with typical industry values. The reagent costs are based on recent supplier quotes received for White Bluff.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Pebble Lime	$/ton	$130.0
High Quality Water	$/1000 gal	$2.00
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Aux Power Cost[1]	$/MWh	$43.35

Note 1: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the Dry FGD system.

Table 4-2: Variable O&M Rates and First Year Costs, per Unit

	Units	Value
Dry FGD System Parameters		
Reagent Consumption	lb/hr	5,900
Byproduct Waste Production	lb/hr	13,000
Aux Power Consumption	kW	11,000
High Quality Water Consumption	gpm	65
Low Quality Water Consumption	gpm	775
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$2,422,000
Byproduct Waste Disposal Cost	$/year	$308,000
Aux Power Cost	$/year	$3,012,000
Water Cost	$/year	$205,000
Bag and Cage Replacement Cost	$/year	$372,000
Total First Year Variable O&M Cost	**$/year**	**$6,319,000**

Note 1: First year costs are provided in $2015.

Note 2: The first year costs are calculated using an annual capacity factor of 72.1%.

4.4 FIXED OPERATING AND MAINTENANCE COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). Based on the conceptual design for the dry FGD system, the estimated staffing additions are 28 personnel for two systems on adjacent units.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.3% of the project capital. This is a lower value than typical because items such as track work and civil work are high capital cost items with little to no maintenance.

Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs for Dry FGD, per Unit

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor[2]	$/year	$1,660,000
Maintenance Material	$/year	$975,000
Maintenance Labor	$/year	$650,000
Total First Year Fixed O&M Cost	**$/year**	**$3,285,000**

Note 1: First year costs are provided in $2015.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on both units would require 28 operators total. For accounting purposes, this is considered 14 operators per unit.

4.5 SULFUR DESIGN BASIS SENSITIVITY

The average sulfur content of coal received at the White Bluff station is 0.57 lb SO_2/MMBtu; however, the White Bluff station has the ability to receive coal with sulfur content up to 1.2 lb SO_2/MMBtu. In order to provide a system which is capable of meeting the design SO_2 emission rate on a continuous basis through the range of coals delivered to site, the FGD equipment must be designed for the maximum coal sulfur which could be burned in the units.

S&L evaluated the incremental cost impact of designing the FGD system for an inlet sulfur of 1.2 lb SO_2/MMBtu versus a lower inlet sulfur of 0.57 lb SO_2/MMBtu. It is important to note that the majority of the components within the FGD Island are designed to accommodate the maximum volumetric flue gas flowrate from the unit. The size and cost of these components, primarily the absorber vessels, baghouses, and ID fans, remains the same regardless of the inlet design sulfur. In addition, the majority of the BOP scope items which have been included in the capital cost estimate would remain constant regardless of the inlet design sulfur.

The primary equipment which is impacted by the design inlet sulfur would be the reagent handling, reagent preparation, and the waste handling systems. The inlet sulfur has a direct impact on the quantity of SO_2 which is being removed in the FGD system, and therefore a direct impact on the required lime (reagent) consumption rate as well as the quantity of byproduct produced. The following areas and associated equipment are impacted by adjusting the design inlet sulfur:

a. Reagent Storage and Handling System:
   - Two long-term storage silos

b. Reagent Preparation System (FGD Island):
   - Two lime day bins
   - Two detention lime slakers
   - Two lime slurry storage tanks

c. By-product Handling System:
   - Two FGD by-product storage silos

The quantity of byproduct which is recycled through the system to achieve the required performance will remain relatively constant regardless of inlet design sulfur and is therefore not impacted. In addition, the lime slurry and byproduct recycle are continuously circulated in a loop to the units and back to the storage tanks; therefore, a variation in the design sulfur would not significantly impact the sizing of the recycle storage equipment, pumps or piping systems.

The cost differential was determined by vendor quotes who were requested to provide equipment costs for design capacities at each of the design sulfur levels; this is the same approach used to adjust the Alstom budgetary proposal from a design sulfur of 2.0 lb/MMBtu to 1.2 lb/MMBtu for the cost estimate. The following table summarizes the cost differential for the equipment identified above that is impacted by the sulfur design basis:

Equipment	Design Capacity @ 1.2 lb/MMBtu	Design Capacity @ 0.57 lb/MMBtu	Cost Reduction for 1.2 to 0.57 lb/MMBtu[1]
Two long-term storage silos	2,200 tons each	1,000 tons each	- $4,717,000
Two lime day bins	650 tons each	300 tons each	- $321,000
Two detention lime slakers	13 tons/hour each	6 tons/hour each	- $134,000
Two lime slurry storage tanks	2,000 tons each	1,000 tons each	- $472,000

Two FGD by-product storage silos	3,000 tons each	1,200 tons each	- $3,391,000
One lime slaking water storage tank	175,000 gallons	100,000 gallons	-$34,000
		TOTAL Differential	**- $9,069,000**

Note 1: Cost Reduction shows the reduction in direct installed capital cost including reductions associated with BOP, i.e. reduced foundation sizes.

The reduction in the total direct installed costs associated with reducing the design sulfur level from 1.2 lb SO_2/MMBtu to 0.57 lb SO_2/MMBtu is approximately $9M.

5. SUMMARY

The cost estimate for the White Bluff Units 1&2 Dry FGD systems is based on the addition of two SDA FGD systems for SO_2 removal. The attached capital estimate for the White Bluff Dry FGD system is based on this technical basis.

6. ATTACHMENTS

1. White Bluff DFGD Project Units 1 and 2 Conceptual Capital Cost Estimate, Sargent & Lundy Estimate No. 33387A
2. White Bluff DFGD Project Units 1 and 2 Conceptual Cost Estimate Cash Flow, Sargent & Lundy Estimate No. 33387A
3. White Bluff DFGD Project Units 1 and 2 Level 1 Preliminary Execution Schedule
4. Monthly Progress Payment Schedule for White Bluff DFGD Project
5. S&L Estimating Documentation: Indirects and Construction Equipment included in Crew Rates
6. S&L Estimating Documentation: Escalation Projections
7. White Bluff DFGD Project Units 1 and 2 Conceptual General Arrangement Drawing
8. Entergy Basis of Contingency

ATTACHMENT 1

Conceptual Capital Cost Estimate

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Estimator	A. KOCI
Labor rate table	15ARPBL
Project No.	13027-002
Client	ENTERGY ARKANSAS
Station Name	WHITE BLUFF
Unit	1 & 2
Estimate Date	12/18/2015
Reviewed By	BA
Approved By	MNO
Estimate No.	33387B
Cost index	ARPBL

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	83,083,008		1,085,764
Material	50,642,339		
Subcontract	313,285,100		
Process Equipment	23,037,000		
	470,047,447	**470,047,447**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	5,816,000		
91-2 Cost Due To OT 5-10's	11,616,000		
91-4 Per Diem	10,858,000		
91-5 Consumables	831,553		
91-6 Freight on Material	2,532,000		
91-8 Sales Tax	7,821,000		
91-9 Contractors G&A	16,696,000		
91-10 Contractors Profit	8,348,000		
	64,518,553	**534,566,000**	
Indirect Costs:			
93-1 Engineering Services	23,000,000		
93-4 SU/S Parts/ Initial Fills	300,000		
93-5 Technical Field Advisors	600,000		
93-8 EPC Fee	55,847,000		
	79,747,000	**614,313,000**	
Escalation:			
96-1 Escalation on Material	6,012,000		
96-2 Escalation on Labor	18,769,000		
96-3 Escalation on Subcontract	37,429,000		
96-4 Escalation on Process Eq	2,115,000		
96-5 Escalation on Indirects	11,600,000		
	75,925,000	**690,238,000**	
Total EPC Cost		***690,238,000***	
Owner's Costs:			
99-1 Owner's Costs	58,546,000		
	58,546,000	**748,784,000**	
Third Party Services:			
100 CM Oversight	4,969,000		
102 Start-up Oversight	550,000		
103 Owner's Engineer	6,750,000		
104 Performance Testing	275,000		
	12,544,000	**761,328,000**	
Project Contingency :			
110 Project Contingency	102,810,000		
	102,810,000	**864,138,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	2,273,000		
	2,273,000	**866,411,000**	
Interest During Construction:			
130 Interest During Constr.	125,078,000		
	125,078,000	**991,489,000**	
Total		***991,489,000***	

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
10	FGD ISLAND	297,904,000	(1,649,000)		-7,814	(680,533)	295,574,467
101	FGD ISLAND FOUNDATIONS AND ENCLOSURES			14,838,628	254,893	18,939,033	33,777,661
102	REAGENT HANDLING SYSTEM	6,000,000	2,046,000	3,162,954	59,192	4,646,650	15,855,604
105	BYPRODUCT HANDLING SYSTEM	7,713,100	6,872,000	1,089,675	107,800	7,935,771	23,610,546
111	FLUE GAS SYSTEM			3,267,828	113,961	7,898,036	11,165,864
121	CIVIL BOP	570,000		8,073,474	106,878	11,535,049	20,178,523
151	MECHANICAL BOP	998,000	1,969,000	6,882,913	115,659	9,189,021	19,038,934
190	DEMOLITION / RELOCATION	100,000		1,578,182	33,735	2,546,302	4,224,484
201	ELECTRICAL BOP SYSTEM		12,299,000	10,665,684	290,576	20,231,688	43,196,372
211	INSTRUMENTATION AND CONTROLS BOP SYSTEM		1,500,000	1,083,000	10,884	841,993	3,424,993
	TOTAL DIRECT	313,285,100	23,037,000	50,642,339	1,085,764	83,083,008	470,047,447

Note: Negative costs included in the cost estimate are due to adjustments to the FGD Budgetary Proposal which was based on a design sulfur of 2.0 lb/MMBTU.
Cost adjustments are included to adjust the design sulfur basis to 1.2 lb/MMBTU.

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
10			FGD ISLAND									
	23.00.00		STEEL									
		23.13.75	SILO									
			SILO - LIME DAY BINS 650 TONS - EQUIPMENT ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS		(273,000)			73.12 /MH		(273,000)
			SILO - LIME DAY BINS 650 TONS - LABOR ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS				-690	73.12 /MH	(50,428)	(50,428)
			SILO				(273,000)		-690		(50,428)	(323,428)
			STEEL				(273,000)		-690		(50,428)	(323,428)
	31.00.00		MECHANICAL EQUIPMENT									
		31.45.00	FGD EQUIPMENT									
			DRY FGD -UNITS 1 & 2 FGD ISLAND - EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	152,030,000		-		97.28 /MH		152,030,000
			DRY FGD -UNITS 1 & 2 FGD ISLAND - INSTALLATION COST	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	145,874,000		-		97.28 /MH		145,874,000
			DRY FGD - INLUDES ABSORBERS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BAGHOUSES	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES REGEANT PREP EQUIPMENT FROM DAY SILOS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BYPRODUCT RECYCLE PREPARATION EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES ID BOOSTER FANS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES PROCESS INSTRUMENTATION AND DCS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES INTERCONNECTING WIRING, PIPING ETC... WITHIN FGD ISLAND	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES DUCTWORK FROM INLET FLANGE TO OUTLET BOOSTER FAN FLANGE	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			FLOW MODEL	INCLUDED WITH ALSTOM PROPOSAL	1.00 LT	-		-		/MH		
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - EQUIPMENT ONLY	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-	(1,300,000)	-		90.81 /MH		(1,300,000)
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - LABOR	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-		-	-6,370	90.81 /MH	(578,470)	(578,470)
			FGD EQUIPMENT			297,904,000	(1,300,000)		-6,370		(578,470)	296,025,530
			MECHANICAL EQUIPMENT			297,904,000	(1,300,000)		-6,370		(578,470)	296,025,530
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - EQUIPMENT ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-	(76,000)	-		68.48 /MH		(76,000)
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - LABOR ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-		-	-754	68.48 /MH	(51,635)	(51,635)
			MATERIAL HANDLING EQUIPMENT				(76,000)		-754		(51,635)	(127,635)
			MATERIAL HANDLING EQUIPMENT				(76,000)		-754		(51,635)	(127,635)
			10 FGD ISLAND			297,904,000	(1,649,000)		-7,814		(680,533)	295,574,467
101			FGD ISLAND FOUNDATIONS AND ENCLOSURES									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILING					961,632	13,324		1,445,136	2,406,768
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	50.00 EA	-	-	92,850	1,264	108.46 /MH	137,133	229,983
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	72.00 EA	-	-	133,704	1,821	108.46 /MH	197,472	331,176
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 1 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 2 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			CAISSON					1,043,634	14,211		1,541,379	2,585,013

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK					**2,005,266**	**27,536**		**2,986,515**	**4,991,781**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	432.00 CY	-	-	99,360	3,476	59.71 /MH	207,544	306,904
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 1 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 2 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWER FOUNDATION	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWERS FOUNDATIONS	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	LIME SLURRY FEED TANKS	400.00 CY	-	-	92,000	3,218	59.71 /MH	192,170	284,170
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 1 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 2 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE					**1,938,900**	**67,828**		**4,049,985**	**5,988,885**
			CONCRETE					**1,938,900**	**67,828**		**4,049,985**	**5,988,885**
	23.00.00		**STEEL**									
		23.17.00	**GALLERY**									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	4,000.00 SF	-	-	60,000	460	66.07 /MH	30,377	90,377
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	BYPRODUCTS RECYCLE EQUIPMENT BLDG	5,760.00 SF	-	-	86,400	662	66.07 /MH	43,743	130,143
			3" HEAVY DUTY GRATING	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	200.00 SF	-	-	11,200	39	66.07 /MH	2,582	13,782
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	3,000.00 LF	-	-	159,000	621	66.07 /MH	41,009	200,009
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	4,320.00 LF	-	-	228,960	894	66.07 /MH	59,053	288,013
			SELF CLOSING SWING GATE - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	40.00 EA	-	-	11,200	184	66.07 /MH	12,151	23,351
			SELF CLOSING SWING GATE - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	58.00 EA	-	-	16,240	267	66.07 /MH	17,619	33,859
			LADDER	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	800.00 LF	-	-	40,000	368	66.07 /MH	24,302	64,302
			LADDER	BYPRODUCTS RECYCLE EQUIPMENT BLDG	1,100.00 LF	-	-	55,000	506	66.07 /MH	33,415	88,415
			STAIR SYSTEM	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	2,400.00 SF	-	-	218,400	3,172	66.07 /MH	209,601	428,001
			STAIR SYSTEM	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,500.00 SF	-	-	318,500	4,626	66.07 /MH	305,669	624,169
			GALLERY					**1,204,900**	**11,798**		**779,520**	**1,984,420**
		23.25.00	**ROLLED SHAPE**									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	REAGENT PREP ENCLOSURE 50'X50' GALLERY SUPPORT	200.00 TN	-	-	716,000	5,057	92.62 /MH	468,423	1,184,423
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	BYPRODUCTS RECYCLE EQUIPMENT BLDG	288.00 TN	-	-	1,031,040	7,283	92.62 /MH	674,529	1,705,569
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U1 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U2 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	500.00 TN	-	-	1,280,000	9,195	92.62 /MH	851,678	2,131,678
			BUILDING MIX, TWO COAT PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	720.00 TN	-	-	1,843,200	13,241	92.62 /MH	1,226,417	3,069,617
			ROLLED SHAPE					**5,402,720**	**38,437**		**3,560,015**	**8,962,735**
			STEEL					**6,607,620**	**50,235**		**4,339,534**	**10,947,154**
	24.00.00		**ARCHITECTURAL**									
		24.17.00	**ELEVATOR**									
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			ELEVATOR					318,700	1,885		199,892	518,592
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	1.00 LT	-	-	20,000	115	92.62 /MH	10,646	30,646
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					30,000	230		21,292	51,292
		24.37.00	ROOFING									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U1 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U2 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED- USER DEFINED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	2,500.00 SF	-	-	19,425	862	35.02 /MH	30,190	49,615
			METAL, INSULATED- USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,600.00 SF	-	-	27,972	1,241	35.02 /MH	43,473	71,445
			ROOFING					157,289	2,782		97,436	254,725
		24.41.00	SIDING									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U1 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U2 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	REAGENT PREP ENCLOSURE	10,000.00 SF	-	-	165,600	1,023	79.59 /MH	81,420	247,020
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	14,400.00 SF	-	-	238,464	1,473	79.59 /MH	117,244	355,708
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U1 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,260.00 SF	-	-	85,345	1,238	79.59 /MH	98,496	183,841
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U2 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,280.00 SF	-	-	85,410	1,238	79.59 /MH	98,571	183,981
			SIDING					655,963	5,473		435,626	1,091,589
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			PENTHOUSE HEATING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			PENTHOUSE HEATING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U1 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U2 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS					323,000	423		30,358	353,358
			ARCHITECTURAL					1,484,952	10,794		784,604	2,269,556
	31.00.00		MECHANICAL EQUIPMENT									
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' FIRE PROTECTION ALLOWANCE	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG' FIRE PROTECTION ALLOWANCE	10,800.00 SF	-	-	59,400	832	68.48 /MH	56,956	116,356
			FIRE PROTECTION EQUIPMENT & SYSTEM					86,900	1,217		83,325	170,225
		31.83.00	TANK									
			TANK - MOVE OIL TANK FROM USED OIL SHED AND REINSTALL AT WASTE MANAGEMENT FACILITY	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 EA	-	-	-	345	90.81 /MH	31,314	31,314
			TANK						345		31,314	31,314
			MECHANICAL EQUIPMENT					86,900	1,562		114,639	201,539
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	64.10 /MH	3,684	58,684
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	64.10 /MH	7,957	126,757
			HVAC, MISCELLANEOUS					173,800	182		11,641	185,441
			HVAC					173,800	182		11,641	185,441
	36.00.00		INSULATION									
		36.13.00	DUCT									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U1 BAGHOUSE INSUILATION TOP, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U2 BAGHOUSE INSULATIOIN - TOPS, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			DUCT					**2,367,390**	**96,576**		**6,640,559**	**9,007,949**
			INSULATION					**2,367,390**	**96,576**		**6,640,559**	**9,007,949**
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	63.63 /MH	7,899	126,699
			LIGHTING ACCESSORY (FIXTURE)					**173,800**	**182**		**11,556**	**185,356**
			ELECTRICAL EQUIPMENT					**173,800**	**182**		**11,556**	**185,356**
			101 FGD ISLAND FOUNDATIONS AND ENCLOSURES					**14,838,628**	**254,893**		**18,939,033**	**33,777,661**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNLOADING SHED 200' X 75 WIDE	63.00 EA	-	-	120,204	1,666	108.46 /MH	180,642	300,846
			PILING					**120,204**	**1,666**		**180,642**	**300,846**
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	SUBSTRUCTURE 2200 TON LIME STORAGE SILOS	100.00 EA	-	-	185,700	2,529	108.46 /MH	274,267	459,967
			CAISSON					**185,700**	**2,529**		**274,267**	**459,967**
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	REAGENT HANDLING SYSTEM UPGRADE AND EXTEND LIME RAIL TRACK TO AVOID BLOCKING ACCESS BY 150 CAR COAL TRAINS	9,060.00 TF	-	-	1,540,200	15,621	81.27 /MH	1,269,493	2,809,693
			TRACKWORK - EXTEND LIME RAIL SPUR AND RELOCATE SWITCH 2060 FT	RELOCATE COAL TRACK SWITCH TO WEST TO AVOID INTERFERENCE WITH 150 CAR COAL TRAINS	1.00 LS	-	-	374,000	7,989	81.27 /MH	649,226	1,023,226
			TRACKWORK					**1,914,200**	**23,609**		**1,918,719**	**3,832,919**
			CIVIL WORK					**2,220,104**	**27,803**		**2,373,628**	**4,593,732**
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	SUBSTRUCTURE 2-2200 TON LIME STORAGE SILOS	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75 WIDE	925.00 CY	-	-	212,750	7,443	59.71 /MH	444,393	657,143
			CONCRETE					**350,750**	**12,270**		**732,649**	**1,083,399**
			CONCRETE					**350,750**	**12,270**		**732,649**	**1,083,399**
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75 WIDE x15' TALL	15,000.00 SF	-	-	525,000	4,828	92.62 /MH	447,131	972,131
			PRE-ENGINEERED BUILDING					**525,000**	**4,828**		**447,131**	**972,131**
			ARCHITECTURAL					**525,000**	**4,828**		**447,131**	**972,131**
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 2200 TON LIME STORAGE SILO	ERECTED - 46' DIA X 154' TALL EA - OPTION 2	2.00 LS	6,000,000				59.71 /MH		6,000,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO			6,000,000			0			6,000,000
			MISCELLANEOUS STRUCTURAL ITEM			6,000,000			0			6,000,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			CRANES & HOISTS - & TROLLEYS ALLOWANCE	REAGENT HANDLING SYSTEM	1.00 LT	-	275,000	-		68.48 /MH		275,000
			CRANES & HOISTS				275,000					275,000
			MECHANICAL EQUIPMENT				275,000					275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - VACUUM EXHAUSTER WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	2.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - RECEIVING PANS UNDER RAIL CARS	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - FILTER SEPARATORS ON TOP OF SILO	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRANSPORT SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - PRESSURE BLOWERS WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	3.00 LS	-		-		/MH		
			LIME HANDLING SYSTEM - PRESSURE FEEDERS	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	8,000	-		68.48 /MH		8,000
			LIME HANDLING SYSTEM - FREIGHT		1.00 LS	-	50,000	-		68.48 /MH		50,000
			MATERIAL HANDLING EQUIPMENT				1,058,000		6,611		452,755	1,510,755
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.48 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER -	IN UNLOADING SHED 200'X75' WIDE	1.00 LT	-	225,000	-	3,103	92.62 /MH	287,441	512,441
			RAIL CAR UNLOADER				225,000		3,103		287,441	512,441
			MATERIAL HANDLING EQUIPMENT				1,508,000		9,715		740,197	2,248,197
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	2-2200 TON LIME STORAGE SILOS	3,600.00 SF	-	-	39,600	41	64.10 /MH	2,652	42,252
			HVAC, MISCELLANEOUS					39,600	41		2,652	42,252
			HVAC					39,600	41		2,652	42,252
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	500.00 LF	-	38,000		540	77.36 /MH	41,792	79,792
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	2,500.00 LF	-	225,000		3,966	77.36 /MH	306,772	531,772
			CARBON STEEL, STRAIGHT RUN				263,000		4,506		348,565	611,565
			PIPING				263,000		4,506		348,565	611,565
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	4200 TON LIME STORAGE SILO	2,500.00 SF	-	-	27,500	29	63.63 /MH	1,828	29,328
			LIGHTING ACCESSORY (FIXTURE)					27,500	29		1,828	29,328
			ELECTRICAL EQUIPMENT					27,500	29		1,828	29,328
			102 REAGENT HANDLING SYSTEM			6,000,000	2,046,000	3,162,954	59,192		4,646,650	15,855,604
105			BYPRODUCT HANDLING SYSTEM									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	21.00.00		**CIVIL WORK**									
		21.54.00	**CAISSON**									
			2.5 FT DIA X 30 FT DEEP CAISSON	ASH SILO AND FGD BYPRODUCT SILOS	125.00 EA	-	-	232,125	3,161	108.46 /MH	342,833	574,958
			CAISSON					**232,125**	**3,161**		**342,833**	**574,958**
			CIVIL WORK					**232,125**	**3,161**		**342,833**	**574,958**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FGD BYPRODUCT SILOS	614.00 CY	-	-	141,220	4,940	59.71 /MH	294,981	436,201
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FLY ASH BLENDING SILO	67.00 CY	-	-	15,410	539	59.71 /MH	32,188	47,598
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	FOR TRUCK SCALES	144.00 CY	-	-	33,120	1,159	59.71 /MH	69,181	102,301
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	MISC	100.00 CY	-	-	23,000	805	59.71 /MH	48,043	71,043
			CONCRETE					**212,750**	**7,443**		**444,393**	**657,143**
			CONCRETE					**212,750**	**7,443**		**444,393**	**657,143**
	23.00.00		**STEEL**									
		23.13.75	**SILO**									
			NEW 250 TON FLYASH BLENDING BIN SILO - 24FT DIA X 72 FT HIGH - ERECTION AND FREIGHT INCLUDED	SILO	1.00 EA		275,000		2,839	73.12 /MH	207,594	482,594
			SILO				**275,000**		**2,839**		**207,594**	**482,594**
			STEEL				**275,000**		**2,839**		**207,594**	**482,594**
	26.00.00		**MISCELLANEOUS STRUCTURAL ITEM**									
		26.13.00	**CONCRETE SILO**									
			CONCRETE SILO - 3000 TON FGD BYPRODUCT SILO	ERECTED - 52' DIA X 162' TALL EA	2.00 LS	7,600,000				59.71 /MH		7,600,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	10,000			73.12 /MH		10,000
			CONCRETE SILO - FREIGHT		1.00 LS	-	70,000			73.12 /MH		70,000
			CONCRETE SILO			**7,600,000**	**80,000**		**0**			**7,680,000**
			MISCELLANEOUS STRUCTURAL ITEM			**7,600,000**	**80,000**		**0**			**7,680,000**
	33.00.00		**MATERIAL HANDLING EQUIPMENT**									
		33.13.00	**BYPRODUCT HANDLING EQUIPMENT**									
			PNEUMATIC ASH CONVEYORS	EQUIPMENT INCLUDES FREIGHT	1.00 LS	-	5,655,000	-		73.12 /MH		5,655,000
			PNEUMATIC ASH CONVEYORS	INSTALLATION COST	1.00 LT	-		-	79,293	73.12 /MH	5,797,912	5,797,912
			BLOWERS, PRESSURE FEEDERS, TRANSPORT PIPING AND VACUUM / PRESSURE RELIEF VALVES	INCLUDED ABOVE	1.00 LT	-		-		73.12 /MH		
			-FOUR PIN MIXERS BELOW CONCRETE SILOS INCL ALL VALVES AND ACCESSORIES		1.00 LT	-	540,000	-	3,347	73.12 /MH	244,742	784,742
			-DRY UNLOADING SPOUT BELOW THE PRODUCT SILO		2.00 EA	-	60,000	-	258	73.12 /MH	18,877	78,877
			AIRSLIDE CONVEYORS FROM BLENDING BIN MIXER/PIPE CONVEYOR, INCL ALL VALVES AND ACCESSORIES		4.00 EA	-	80,000	-	688	73.12 /MH	50,327	130,327
			BYPRODUCT HANDLING EQUIPMENT				**6,335,000**		**83,587**		**6,111,857**	**12,446,857**
		33.57.00	**SCALE**									
			SCALE - NEW TRUCK SCALES	BYPRODUCT HANDLING SYSTEM	2.00 EA	-	182,000	-	460	68.48 /MH	31,485	213,485
			SCALE				**182,000**		**460**		**31,485**	**213,485**
			MATERIAL HANDLING EQUIPMENT				**6,517,000**		**84,046**		**6,143,342**	**12,660,342**
	34.00.00		**HVAC**									
		34.37.00	**DUST COLLECTOR**									
			DUST COLLECTOR - INSTALLED COST		1.00 LS	113,100	-			64.10 /MH		113,100
			DUST COLLECTOR			**113,100**						**113,100**
			HVAC			**113,100**						**113,100**
	35.00.00		**PIPING**									
		35.14.10	**CARBON STEEL, STRAIGHT RUN**									
			12 IN DIA, 3/8 IN STD	CONVEYOR PIPING	5,000.00 LF	-	-	496,000	7,931	77.36 /MH	613,545	1,109,545
			12 IN DIA, 3/8 IN STD	12" TIE IN PIPING TO BYPRODUCT SILO	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	FROM THE EXISTING 50 TPH FLY ASH PRESSURE SYSTEM	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863
			CARBON STEEL, STRAIGHT RUN					644,800	10,310		797,608	1,442,408
			PIPING					644,800	10,310		797,608	1,442,408
			105 BYPRODUCT HANDLING SYSTEM			**7,713,100**	**6,872,000**	**1,089,675**	**107,800**		**7,935,771**	**23,610,546**
111			**FLUE GAS SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILING					526,608	7,297		791,384	1,317,992
			CIVIL WORK					526,608	7,297		791,384	1,317,992
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 1 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 2 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			CONCRETE					444,360	15,545		928,182	1,372,542
			CONCRETE					444,360	15,545		928,182	1,372,542
	23.00.00		STEEL									
		23.15.00	DUCTWORK									
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			97.25 /MH		
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			97.25 /MH		
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			92.62 /MH		
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	TN	-	-			92.62 /MH		
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - CHIMNEY	UNIT 1 FLUE GAS SYSTEM	1.00 LT	-	-	110,000	4,109	47.61 /MH	195,639	305,639
			PAINTING					110,000	4,109		195,639	305,639
			PAINTING & COATING					110,000	4,109		195,639	305,639
	31.00.00		MECHANICAL EQUIPMENT									
		31.27.00	DAMPERS & ACCESSORIES									
			DAMPERS & ACCESSORIES	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	SF	-				97.25 /MH		
			DAMPERS & ACCESSORIES	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	SF	-				97.25 /MH		
		31.33.00	EXPANSION JOINT									
			EXPANSION JOINT	UNIT 1 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	LF	-				97.25 /MH		
			EXPANSION JOINT	UNIT 2 FLUE GAS SYSTEM - INCLUDED IN ALSTOM'S QUOTE	LF	-				97.25 /MH		
	36.00.00		INSULATION									
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 1 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 2 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			DUCT					2,186,860	87,010		5,982,831	8,169,691
			INSULATION					2,186,860	87,010		5,982,831	8,169,691
			111 FLUE GAS SYSTEM					**3,267,828**	**113,961**		**7,898,036**	**11,165,864**
121			**CIVIL BOP**									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"		300,000.00 SF	-	-		690	182.33 /MH	125,745	125,745
			STRIP & STOCKPILE TOPSOIL - ONSITE		40,000.00 CY	-	-		5,287	182.33 /MH	964,044	964,044
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING	600,000.00 SF	-	-		1,379	182.33 /MH	251,490	251,490
			STRIP & STOCKPILE TOPSOIL - ONSITE	SITE GRADING	160,000.00 CY	-	-		21,149	182.33 /MH	3,856,175	3,856,175
			STRIP & STOCKPILE TOPSOIL						28,506		5,197,453	5,197,453
		21.17.00	EXCAVATION									
			MASS EXCAVATION, COMMON EARTH USING 1.5 CY BACKHOE AND (6) 12 CY DUMP TRUCKS, 4 MI ROUNDTRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		523	182.33 /MH	95,356	95,356
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS		12,600.00 CY	-	-		4,345	79.31 /MH	344,588	344,588
			EXCAVATION						4,868		439,945	439,945
		21.19.00	DISPOSAL									
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		483	79.31 /MH	38,288	38,288
			DISPOSAL						483		38,288	38,288
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,000.00 CY	-	-		172	79.31 /MH	13,674	13,674
			BACKFILL						172		13,674	13,674
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING	1.00 LT	-	-	110,000	2,299	72.14 /MH	165,839	275,839
			STORM DRAINAGE UTILITIES					110,000	2,299		165,839	275,839
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK		33,334.00 SY	-	-	355,007	1,149	97.31 /MH	111,853	466,860
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING	66,667.00 SY	-	-	710,004	2,299	97.31 /MH	223,702	933,706
			EROSION AND SEDIMENTATION CONTROL					1,065,011	3,448		335,555	1,400,566
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ROAD - ROAD UPGRADE	BYPRODUCT HAUL ROAD - EAST OF COAL PILE	10,000.00 LF	-	-	500,000	8,046	78.37 /MH	630,563	1,130,563
			BITUMINOUS ROAD - ELIMINATE CHICANE CURVES AT LOW PRESSURE SERVICE WATER PUMPS		1.00 LT	-	-	500,000		78.37 /MH		500,000
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ROADWORK 24' WIDE 4" ASPHALT	SITE GRADING	1,668.00 LF	-	-	201,828	2,013	78.37 /MH	157,767	359,595
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW BYPASS LANE (ON WEST SIDE)	9,000.00 LF	-	-	603,000	1,655	78.37 /MH	129,716	732,716
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW LEFT TURN LANE (SOUTH BOUND)	3,000.00 LF	-	-	201,000	552	78.37 /MH	43,239	244,239
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW MERGE LANE (NORTH BOUND)	4,175.00 LF	-	-	279,725	768	78.37 /MH	60,174	339,899
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW RIGHT TURN LANE (NORTH BOUND)	4,000.00 LF	-	-	268,000	736	78.37 /MH	57,651	325,651
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), UPGRADE, REMOVE EXISTING ASPHALT, SUBGRADE PREP NEW BASE AND NEW ASPHALT	4,250.00 LF	-	-	514,250	3,126	78.37 /MH	245,019	759,269
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), EXTENSION, 24' WIDE	580.00 LF	-	-	84,100	907	78.37 /MH	71,055	155,155
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	WIDENING OF EXISTING MAIN PLANT ROAD FROM CONTRACTOR HAUL ROAD (HWY 46 SPUR) TO MAIN GUARD HOUSE	2,900.00 LF	-	-	194,300	1,767	78.37 /MH	138,454	332,754
			ROAD, PARKING AREA, & SURFACED AREA					3,346,203	19,569		1,533,638	4,879,841
		21.71.00	TRACKWORK									
			SIGNAL SYSTEM - RR CROSSING SIGNALS AND GATES	CONTRACTOR HAUL ROAD (HWY 46 SPUR) CROSSING	1.00 LS	220,000	-			/MH		220,000
			TRACKWORK			220,000						220,000
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	10.00 AC	-	-	780,000	9,195	79.31 /MH	729,287	1,509,287

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK, MISCELLANEOUS					780,000	9,195		729,287	1,509,287
			CIVIL WORK			220,000		5,301,214	68,540		8,453,679	13,974,892
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	75.00 CY	-	-	17,250	603	59.71 /MH	36,032	53,282
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	555.00 CY	-	-	127,650	4,466	59.71 /MH	266,636	394,286
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,800.00 CY	-	-	216,000	2,586	59.71 /MH	154,422	370,422
			CONCRETE					362,280	7,703		459,973	822,253
		22.15.00	EMBEDMENT									
			EMBEDMENTS, CARBON STEEL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	10,000.00 LB	-	-	30,000	575	51.10 /MH	29,368	59,368
			EMBEDMENT					30,000	575		29,368	59,368
		22.17.00	FORMWORK									
			BUILT UP INSTALL & STRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	11,000.00 SF	-	-	27,500	2,529	81.61 /MH	206,370	233,870
			FORMWORK					27,500	2,529		206,370	233,870
		22.25.00	REINFORCING									
			UNCOATED A615 GR60	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	135.00 TN	-	-	138,375	2,793	56.35 /MH	157,391	295,766
			REINFORCING					138,375	2,793		157,391	295,766
			CONCRETE					558,155	13,600		853,102	1,411,257
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA, 45 FT X 45 FT	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	56,700	791	92.62 /MH	73,298	129,998
			SHELL ONLY, STEEL UNINSULATED 22 GA, 200 FT X 75 FT x 15' TALL	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	420,000	5,862	92.62 /MH	542,945	962,945
			PRE-ENGINEERED BUILDING	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					486,700	6,768		626,888	1,113,588
		24.41.00	SIDING									
			INSULATION, 2 IN THICK FIBERGLASS,	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	3,240.00 SF	-	-	3,888	37	79.59 /MH	2,964	6,852
			INSULATION, 2 IN THICK FIBERGLASS,	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	8,250.00 SF	-	-	9,900	95	79.59 /MH	7,547	17,447
			SIDING					13,788	132		10,511	24,299
			ARCHITECTURAL					500,488	6,900		637,400	1,137,888
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.99.00	MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS									
			MISCELLANEOUS STRUCTURAL ITEM - WATER INTAKE PUMP STRUCTURE - ONE BAY		1.00 LS	-	-	1,110,000	15,537	92.62 /MH	1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS					1,110,000	15,537		1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM					1,110,000	15,537		1,439,017	2,549,017
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	15,000	172	47.61 /MH	8,209	23,209
			PAINTING					15,000	172		8,209	23,209
			PAINTING & COATING					15,000	172		8,209	23,209
	31.00.00		MECHANICAL EQUIPMENT									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.41.00	**FIRE PROTECTION EQUIPMENT & SYSTEM**									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	11,138	156	68.48 /MH	10,679	21,817
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, FIRE PROTECTION ALLOWANCE	15,000.00 SF	-	-	82,500	1,155	68.48 /MH	79,106	161,606
			FIRE PROTECTION EQUIPMENT & SYSTEM					**93,638**	**1,311**		**89,786**	**183,423**
			MECHANICAL EQUIPMENT					**93,638**	**1,311**		**89,786**	**183,423**
	34.00.00		**HVAC**									
		34.99.00	**HVAC, MISCELLANEOUS**									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	64.10 /MH	1,492	23,767
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	165,000	172	64.10 /MH	11,052	176,052
			HVAC, MISCELLANEOUS					**187,275**	**196**		**12,544**	**199,819**
			HVAC					**187,275**	**196**		**12,544**	**199,819**
	36.00.00		**INSULATION**									
		36.99.00	**INSULATION, MISCELLANEOUS**									
			INSULATION - ROOF INSULATION	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,430	23	51.10 /MH	1,189	3,619
			INSULATION - ROOF INSULATION	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	18,000	172	51.10 /MH	8,810	26,810
			INSULATION, MISCELLANEOUS					**20,430**	**196**		**10,000**	**30,430**
			INSULATION					**20,430**	**196**		**10,000**	**30,430**
	41.00.00		**ELECTRICAL EQUIPMENT**									
		41.37.00	**LIGHTING ACCESSORY (FIXTURE)**									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	63.63 /MH	1,481	23,756
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, LIGHTING ALLOWANCE	15,000.00 SF	-	-	165,000	172	63.63 /MH	10,971	175,971
			LIGHTING ACCESSORY (FIXTURE)					**187,275**	**196**		**12,452**	**199,727**
		41.99.00	**ELECTRICAL EQUIPMENT, MISCELLANEOUS**									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS -	ADD BAY TO EXISTING INTAKE STRUCTURE FOR 3RD PUMP	1.00 LT	-	-	100,000	230	82.05 /MH	18,862	118,862
			ELECTRICAL EQUIPMENT, MISCELLANEOUS					**100,000**	**230**		**18,862**	**118,862**
			ELECTRICAL EQUIPMENT					**287,275**	**426**		**31,314**	**318,589**
	71.00.00		**PROJECT INDIRECT**									
		71.25.00	**CONSULTANT, THIRD PARTY**									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	200,000	-			/MH		200,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000
			CONSULTANT, THIRD PARTY			**350,000**						**350,000**
			PROJECT INDIRECT			**350,000**						**350,000**
			121 CIVIL BOP			**570,000**		**8,073,474**	**106,878**		**11,535,049**	**20,178,523**
151			**MECHANICAL BOP**									
	11.00.00		**DEMOLITION**									
		11.21.00	**CIVIL WORK**									
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	BYPRODUCT PIPE FROM RACK	100.00 LF	-	-		172	79.31 /MH	13,674	13,674
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	REAGENT UNLOADING PIPE FROM RACK	200.00 LF	-	-		345	79.31 /MH	27,348	27,348
			CIVIL WORK						**517**		**41,022**	**41,022**
			DEMOLITION						**517**		**41,022**	**41,022**
	21.00.00		**CIVIL WORK**									
		21.17.00	**EXCAVATION**									
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,430.00 LF	-	-	8,680	526	79.31 /MH	41,715	50,395
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		750.00 LF	-	-	4,553	276	79.31 /MH	21,879	26,431
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		3,000.00 LF	-	-	12,750	966	79.31 /MH	76,575	89,325
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,000.00 LF	-	-	4,250	322	79.31 /MH	25,525	29,775
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		5,260.00 LF	-	-	22,355	1,693	79.31 /MH	134,262	156,617
			EXCAVATION - 8" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,340.00 LF	-	-	9,929	539	79.31 /MH	42,754	52,684
			EXCAVATION - 36" PIPE 4' DEEP PIPE TRENCH & BEDDING	RIVER WATER PIPE TIE IN	20.00 LF	-	-	733	21	79.31 /MH	1,677	2,411
			EXCAVATION - 32" PIPE 4' DEEP PIPE TRENCH & BEDDING	LPSW PIPE	2,100.00 LS	-	-	60,375	1,859	79.31 /MH	147,407	207,782

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	EXCAVATION									
			EXCAVATION - 10" PIPE 4' DEEP PIPE TRENCH & BEDDING	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	15,930	786	79.31 /MH	62,354	78,284
			EXCAVATION - 4" PIPE 4' DEEP PIPE TRENCH & BEDDING	LEACHATE PIPING	3,500.00 LF	-	-	16,905	1,167	79.31 /MH	92,528	109,433
			EXCAVATION					156,460	8,154		646,677	803,138
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	TANK FOUNDATIONS	76.00 EA	-	-	141,132	1,922	108.46 /MH	208,443	349,575
			2.5 FT DIA X 30 FT DEEP CAISSON	COMMON PIPE RACK FOUNDATIONS	186.00 EA	-	-	345,402	4,703	108.46 /MH	510,136	855,538
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCT PIPE RACK FOUNDATIONS	94.00 EA	-	-	174,558	2,377	108.46 /MH	257,811	432,369
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT UNLOADING PIPE RACK FOUNDATIONS	16.00 EA	-	-	29,712	405	108.46 /MH	43,883	73,595
			CAISSON					690,804	9,407		1,020,272	1,711,076
			CIVIL WORK					847,264	17,561		1,666,949	2,514,214
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SPREAD FOOTING FOUNDATION, 4500 PSI - COMPOSITE RATE	3X 35' DIA TANK FDN	81.00 CY	-	-	18,630	652	59.71 /MH	38,914	57,544
			CONCRETE FOUNDATIONS - COMPOSITE RATE	COMMON PIPE RACK FOUNDATIONS	207.00 CY	-	-	47,610	1,666	59.71 /MH	99,448	147,058
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BYPRODUCT PIPE RACK FOUNDATIONS	105.00 CY	-	-	24,150	845	59.71 /MH	50,445	74,595
			CONCRETE FOUNDATIONS - COMPOSITE RATE	REAGENT UNLOADING PIPE RACK FOUNDATIONS	18.00 CY	-	-	4,140	145	59.71 /MH	8,648	12,788
			CONCRETE					94,530	3,307		197,455	291,985
			CONCRETE					94,530	3,307		197,455	291,985
	23.00.00		STEEL									
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	COMMON 500'LX20'W, 400'Lx15'W,400'Lx9'W, ALL 20' HIGH	196.00 TN	-	-	531,160	3,830	92.62 /MH	354,724	885,884
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	BYPRODUCT PIPE RACK, 650LF X6 WIDE X 20' HIGH	39.00 TN	-	-	105,690	762	92.62 /MH	70,583	176,273
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	REAGENT UNLOADING PIPE RACK, 100LF X 6' WIDE X 20' HIGH	6.00 TN	-	-	16,260	117	92.62 /MH	10,859	27,119
			GIRDER					653,110	4,709		436,166	1,089,276
			STEEL					653,110	4,709		436,166	1,089,276
	27.00.00		PAINTING & COATING									
		27.13.00	COATING									
			COATING - CHIMNEY - ACID RESISTANT COATING TOP 100 FT OUTSIDE SHELL		1.00 LS	270,000	-			47.61 /MH		270,000
			COATING			270,000						270,000
			PAINTING & COATING			270,000						270,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.17.00	COMPRESSOR & ACCESSORIES									
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	SERVICE AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	INSTRUMENT AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	SERVICE AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	INSTRUMENT AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR RECEIVER - 1,000 GALLON EA	SERVICE AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			AIR RECEIVER - 1,000 GALLON EA	INSTRUMENT AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			COMPRESSOR & ACCESSORIES				709,200		405		27,707	736,907
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			DELUGE - POWER TRANSFORMERS		3.00 EA	-	-	127,500	1,959	77.36 /MH	151,519	279,019
			FIRE PROTECTION EQUIPMENT & SYSTEM					127,500	1,959		151,519	279,019
		31.65.00	HEAT EXCHANGER									
			HEAT EXCHANGER - SLAKER WATER HEATER 3" IN-LINE, 475 KW		4.00 EA	-	220,000	-	368	63.63 /MH	23,404	243,404
			HEAT EXCHANGER				220,000		368		23,404	243,404
		31.75.00	PUMP									

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.75.00	**PUMP**									
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - MAKEUP WATER PUMPS, 2600 GPM, 200 TDH		2.00 EA	-	96,000	-	577	68.48 /MH	39,514	135,514
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - RECYCLE ASH WATER PUMP, 50 HP		3.00 EA	-	72,000	-	221	68.48 /MH	15,113	87,113
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - LIME SLAKING WATER PIUMPS, 50 HP		2.00 EA	-	48,000	-	147	68.48 /MH	10,075	58,075
			CENTRIFUGAL, VERTICAL, CANNED - LEACHATE PUMPS, 50 HP		2.00 EA	-	134,000	-	828	68.48 /MH	56,673	190,673
			CENTRIFUGAL, VERTICAL, WET PIT - LPSW PUMP, 650 HP		1.00 EA	-	188,000	-	690	68.48 /MH	47,228	235,228
			SUMP, CENTRIFUGAL, WET BEARING - REGENT PREP/RECYCLE SUMP, 120GPM, 150 TDH		4.00 EA	-	220,000	-	276	68.48 /MH	18,891	238,891
			SUMP, CENTRIFUGAL, WET BEARING - LIME SILO & UNLOADING AREA SUMP 120 GPM @ 150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTE ASH SILO AREA SUMP 120GPM @150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTEWATER FORWARDING PUMP TO RECYCLED SLURRY, 100 GPM@150 TDH		4.00 EA	-	28,800	-	294	68.48 /MH	20,150	48,950
			SUMP, SUBMERSIBLE - RECYCLE ASH WATER TANK SUPPLY PUMP, 100 HP		2.00 EA	-	77,000	-	690	68.48 /MH	47,228	124,228
			PUMP				**1,039,800**		**3,998**		**273,763**	**1,313,563**
		31.83.00	**TANK**									
			ATMOSPHERIC, FIELD FABRICATED - LIME SLAKING WATER TANK, 175,000 GALLON	35' DIA X 24' HIGH	1.00 EA	220,000		-		90.81 /MH		220,000
			ATMOSPHERIC, FIELD FABRICATED - RECYCLE ASH WATER TANK, 250,000 GALLON	35' DIA X 36' HIGH	2.00 EA	508,000		-		90.81 /MH		508,000
			TANK			**728,000**						**728,000**
			MECHANICAL EQUIPMENT			**728,000**	**1,969,000**	**127,500**	**6,729**		**476,392**	**3,300,892**
	35.00.00		**PIPING**									
		35.13.01	**SS 304, ABOVE GROUND, PROCESS AREA**									
			1 IN DIA, SCH 40S		1,520.00 LF	-	-	32,832	1,974	77.36 /MH	152,728	185,560
			1.5 IN DIA, SCH 40S		1,380.00 LF	-	-	52,302	2,094	77.36 /MH	161,976	214,278
			2 IN DIA, SCH 40S		2,070.00 LF	-	-	113,022	3,426	77.36 /MH	265,051	378,073
			SS 304, ABOVE GROUND, PROCESS AREA					**198,156**	**7,494**		**579,755**	**777,911**
		35.13.10	**CARBON STEEL, ABOVE GROUND, PROCESS AREA**									
			1 IN DIA, SCH 80		260.00 LF	-	-	2,314	305	77.36 /MH	23,581	25,895
			2 IN DIA, SCH 80		2,260.00 LF	-	-	48,138	3,273	77.36 /MH	253,207	301,345
			2.5 IN DIA, SCH 40		1,000.00 LF	-	-	15,400	1,437	77.36 /MH	111,149	126,549
			3 IN DIA, SCH 40		7,160.00 LF	-	-	125,300	11,028	77.36 /MH	853,130	978,430
			3 IN DIA, SCH 80		1,760.00 LF	-	-	38,720	3,055	77.36 /MH	236,313	275,033
			4 IN DIA, SCH 40		1,000.00 LF	-	-	22,600	1,701	77.36 /MH	131,601	154,201
			6 IN DIA, SCH 40		880.00 LF	-	-	28,248	1,629	77.36 /MH	125,981	154,229
			6 IN DIA, SCH 40 VACUUM PIPE		2,260.00 LF	-	-	72,546	4,182	77.36 /MH	323,543	396,089
			8 IN DIA, SCH 80		3,520.00 LF	-	-	256,608	9,832	77.36 /MH	760,582	1,017,190
			CARBON STEEL, ABOVE GROUND, PROCESS AREA					**609,874**	**36,441**		**2,819,087**	**3,428,961**
		35.13.36	**DUCTILE IRON, ABOVE GROUND, PROCESS AREA**									
			12 IN DIA, - ASHCOLITE PIPE		1,620.00 LF	-	-	162,000	3,594	72.14 /MH	259,256	421,256
			DUCTILE IRON, ABOVE GROUND, PROCESS AREA					**162,000**	**3,594**		**259,256**	**421,256**
		35.14.10	**CARBON STEEL, STRAIGHT RUN**									
			6 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	1,200.00 LF	-	-	27,480	1,214	77.36 /MH	93,899	121,379
			8 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	450.00 LF	-	-	13,905	486	77.36 /MH	37,613	51,518
			8 IN DIA, SCH 40, RECYCLE ASH WATER PIPING	RECYCLE ASH WATER PIPING	2,000.00 LF	-	-	61,800	2,161	77.36 /MH	167,169	228,969
			10 IN DIA, SCH 40, RECYCLE ASH TANK MAKEUP	RECYCLE ASH TANK MAKEUP	450.00 LF	-	-	24,660	610	77.36 /MH	47,216	71,876
			CARBON STEEL, STRAIGHT RUN					**127,845**	**4,471**		**345,897**	**473,742**
		35.15.10	**CARBON STEEL, BURIED**									
			3 IN DIA, SCH 40, WRAPPED		3,000.00 LF	-	-	51,000	2,241	77.36 /MH	173,393	224,393
			4 IN DIA, SCH 40, WRAPPED, LEACHATE PIPING	LEACHATE PIPING	3,500.00 LF	-	-	72,800	2,856	77.36 /MH	220,965	293,765
			6 IN DIA, SCH 40, WRAPPED		750.00 LF	-	-	23,925	776	77.36 /MH	60,021	83,946
			10 IN DIA, SCH 40, WRAPPED, RECYCLE ASH WATER PIPE DISCHARGE BURIED	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	119,700	2,441	77.36 /MH	188,865	308,565
			32 IN DIA, 3/8 IN STD, WRAPPED - LPSW PIPE	LPSW PIPE	2,100.00 LF	-	-	638,610	11,079	77.36 /MH	857,095	1,495,705

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.15.10	**CARBON STEEL, BURIED**									
			36 IN DIA, 3/8 IN STD, WRAPPED - RIVER WATER PIPE	RIVER WATER PIPE - TIE IN	20.00 LF	-	-	6,772	138	77.36 /MH	10,706	17,478
			CARBON STEEL, BURIED					**912,807**	**19,533**		**1,511,045**	**2,423,852**
		35.15.25	**FRP, BURIED**									
			3 IN DIA, TAPER		1,000.00 LF	-	-	14,800	460	77.36 /MH	35,568	50,368
			3 IN DIA, TAPER FRP/HDPE PIPE		2,380.00 LF	-	-	35,224	1,094	77.36 /MH	84,651	119,875
			FRP, BURIED					**50,024**	**1,554**		**120,219**	**170,243**
		35.15.30	**HDPE, BURIED**									
			6 IN DIA, DR 9		1,430.00 LF	-	-	12,870	1,134	77.36 /MH	87,737	100,607
			8 IN DIA, DR 9		1,340.00 LF	-	-	20,770	1,278	77.36 /MH	98,896	119,666
			HDPE, BURIED					**33,640**	**2,413**		**186,633**	**220,273**
		35.36.00	**PIPE SUPPORTS, RACK**									
			SUPPORT SLEEPERS	BYPRODUCT PIPE, 1750LF	125.00 EA	-	-	43,750	575	77.36 /MH	44,460	88,210
			SUPPORT SLEEPERS	REAGENT UNLOADING PIPE, 1500LF	108.00 EA	-	-	37,800	497	77.36 /MH	38,413	76,213
			PIPE SUPPORTS, RACK					**81,550**	**1,071**		**82,873**	**164,423**
		35.45.00	**VALVES**									
			VALVE - 36" 150 LB CS BUTTERFLY, FLANGED		2.00 EA	-	-	79,920	96	77.36 /MH	7,398	87,318
			VALVE - 12" 150 LB CS KNIFE GATE, FLANGED		6.00 EA	-	-	20,160	195	77.36 /MH	15,099	35,259
			VALVE - 12" 150 LB CS GATE VALVE, FLANGED		2.00 EA	-	-	8,920	65	77.36 /MH	5,033	13,953
			VALVE - 10" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	9,200	55	77.36 /MH	4,268	13,468
			VALVE - 10" 150 LB CS BUTTERFLY, FLANGED		5.00 EA	-	-	22,200	138	77.36 /MH	10,670	32,870
			VALVE - 8" 150 LB CS GATE, FLANGED		20.00 EA	-	-	100,000	425	77.36 /MH	32,900	132,900
			VALVE - 6" 150 LB CS GATE, FLANGED		6.00 EA	-	-	19,800	110	77.36 /MH	8,536	28,336
			VALVE - 6" 150 LB CS AIR OPERATED GATE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS AIR OPERATED GLOBE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	3,400	37	77.36 /MH	2,845	6,245
			VALVE - 4" 150 LB CS GATE, FLANGED		3.00 EA	-	-	3,825	25	77.36 /MH	1,921	5,746
			VALVE - 3" AND BELOW CS FOR SERVICE WATER ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" AND BELOW CS FOR SERVICE AIR ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" 150 LB CS GATE, FLANGED		20.00 EA	-	-	15,000	179	77.36 /MH	13,871	28,871
			VALVE - 3" CS PST IND FOR FP 250 LB		6.00 EA	-	-	6,600	54	77.36 /MH	4,161	10,761
			VALVE - 2" AND ABOVE BRONZE VALVES FOR INSTRUMENT AIR ISOLATION		600.00 EA	-	-	78,000	501	77.36 /MH	38,787	116,787
			VALVE - 1" CS FLANGED		4.00 EA	-	-	880	21	77.36 /MH	1,636	2,516
			VALVE - 6" CI POST INDICATOR 250 LB., MECHANICAL JOINT WITH BOXES BURIED VALVE		6.00 EA	-	-	4,080	28	77.36 /MH	2,134	6,214
			VALVES					**2,860,785**	**4,228**		**327,099**	**3,187,884**
			PIPING					**5,036,681**	**80,799**		**6,231,866**	**11,268,547**
	36.00.00		**INSULATION**									
		36.17.01	**PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING**									
			CALCIUM SILICATE W/ALUMINUM JACKETING - 8" PIPE 1.5" THICK		2,520.00 LF	-	-	16,380	487	68.76 /MH	33,460	49,840
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		1,260.00 LF	-	-	3,591	155	68.76 /MH	10,655	14,246
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		5,660.00 LF	-	-	16,131	696	68.76 /MH	47,865	63,996
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.5" PIPE		380.00 LS	-	-	1,083	47	68.76 /MH	3,214	4,297
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.0" PIPE		4,140.00 LS	-	-	10,309	476	68.76 /MH	32,720	43,029
			PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING					**47,494**	**1,860**		**127,914**	**175,408**
			INSULATION					**47,494**	**1,860**		**127,914**	**175,408**
	41.00.00		**ELECTRICAL EQUIPMENT**									
		41.33.00	**HEAT TRACING**									
			HEAT TRACING - 8" PIPE		2,520.00 LS	-	-	18,749	43	63.63 /MH	2,765	21,513
			HEAT TRACING - 3" PIPE		1,260.00 LF	-	-	9,374	22	63.63 /MH	1,382	10,757
			HEAT TRACING - 3" PIPE		5,660.00 LF	-	-	42,110	98	63.63 /MH	6,209	48,320
			HEAT TRACING - 2.5" PIPE		380.00 LS	-	-	2,827	7	63.63 /MH	417	3,244
			HEAT TRACING - 2.0" PIPE		440.00 LS	-	-	3,274	8	63.63 /MH	483	3,756
			HEAT TRACING					**76,334**	**177**		**11,256**	**87,590**
			ELECTRICAL EQUIPMENT					**76,334**	**177**		**11,256**	**87,590**
			151 MECHANICAL BOP			**998,000**	**1,969,000**	**6,882,913**	**115,659**		**9,189,021**	**19,038,934**

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
190			**DEMOLITION / RELOCATION**									
	11.00.00		**DEMOLITION**									
		11.21.00	**CIVIL WORK**									
			CIVIL WORK - REMOVE FENCING & GATES	HAZARDOUS MATERIAL ACCUMULATION BLDG	1,133.00 LF	-	-		91	107.10 /MH	9,763	9,763
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		948	79.31 /MH	75,208	75,208
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH E970 FROM N2055 'TO N1350'	705.00 LF	-	-		1,216	79.31 /MH	96,403	96,403
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH e1350 from n970' to n1180'	210.00 LF	-	-		362	79.31 /MH	28,716	28,716
			CIVIL WORK - DEMO AREA PAVEMENT	ASH HANDLING / ELECT BLDG	1.00 LS	-	-		115	107.10 /MH	12,310	12,310
			CIVIL WORK						**2,732**		**222,400**	**222,400**
		11.22.00	**CONCRETE**									
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	80.00 CY	-	-		230	107.10 /MH	24,621	24,621
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, HAZMAT PAVEMENT DEMO	12.00 CY	-	-		61	107.10 /MH	6,574	6,574
			CONCRETE FOUNDATION - ASH HANDLING MAINT BLDG	ASH HANDLING / ELECT BLDG FDN	225.00 CY	-	-		647	107.10 /MH	69,246	69,246
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	FLOURESCENT LIGHT TUBE DISPOSAL SHED FDN	2.00 CY	-	-		10	107.10 /MH	1,096	1,096
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	USED OIL SHED DEMO	35.00 CY	-	-		101	107.10 /MH	10,772	10,772
			CONCRETE						**1,049**		**112,307**	**112,307**
		11.23.00	**STEEL**									
			STRUCTURAL STEEL DISASSEMBLE BLDG STEEL & TOOL CRIB FOR RELOCATION	ASH HANDLING / ELECT BLDG	52.00 TN	-	-		359	107.10 /MH	38,408	38,408
			STEEL						**359**		**38,408**	**38,408**
		11.24.00	**ARCHITECTURAL**									
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	50,000.00 CF	-	-		632	107.10 /MH	67,707	67,707
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, CONTAINER DISPOSAL AREA	1.00 LT	-	-		287	107.10 /MH	30,776	30,776
			ARCHITECTURAL - DEMO EXISTING INSULATED SIDING & ROOFING , DEMO INTERIOR OFFICES	ASH HANDLING / ELECT BLDG	15,000.00 CF	-	-		862	107.10 /MH	92,328	92,328
			ARCHITECTURAL - BLDG DEMO	COAL DUMPER AIR COMPRESSOR DEMOLITION	100.00 SF	-	-		11	107.10 /MH	1,231	1,231
			ARCHITECTURAL - BLDG DEMO	USED OIL SHED DEMO	600.00 SF	-	-		8	107.10 /MH	812	812
			ARCHITECTURAL						**1,801**		**192,854**	**192,854**
		11.31.00	**MECHANICAL EQUIPMENT**									
			MECHANICAL EQUIPMENT - DEMOLISH SEPTIC TANKS	ASH HANDLING / ELECT BLDG	2.00 EA	-	-		0	107.10 /MH	25	25
			MECHANICAL EQUIPMENT - REMOVE 15 TN BRIDGE CRANE (50 FT SPAN) , CRANE SUPPORT STEEL AND 3 JIB CRANES FGOR RELOCATION	ASH HANDLING / ELECT BLDG	21.00 TN	-	-		290	92.62 /MH	26,828	26,828
			MECHANICAL EQUIPMENT						**290**		**26,852**	**26,852**
		11.35.00	**PIPING**									
			PIPING - REMOVE 12" BA PIPE IN PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		87	107.10 /MH	9,276	9,276
			PIPING - REMOVE 10" FA PIPE	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		76	107.10 /MH	8,125	8,125
			PIPING						**162**		**17,401**	**17,401**
		11.99.00	**DEMOLITION, MISCELLANEOUS**									
			DEMOLITION - MISC	ALLOWANCE	1.00 LT	-	-		2,299	92.62 /MH	212,920	212,920
			DEMOLITION, MISCELLANEOUS						**2,299**		**212,920**	**212,920**
			DEMOLITION						**8,691**		**823,142**	**823,142**
	21.00.00		**CIVIL WORK**									
		21.16.00	**GENERAL EARTHWORK**									
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	HAZARDOUS MATERIAL ACCUMULATION BLDG	300.00 CY	-	-	4,800	138	182.33 /MH	25,149	29,949
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	ASH HANDLING / ELECT BLDG	1,000.00 CY	-	-	16,000	460	182.33 /MH	83,830	99,830
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE 250'X250'X2'	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	5,000.00 CY	-	-	80,000	259	182.33 /MH	47,154	127,154
			GENERAL EARTHWORK					**100,800**	**856**		**156,133**	**256,933**
		21.17.00	**EXCAVATION**									
			EXCAVATION - ALLOWANCE FOR NEW DITCHES	WASTE MANAGEMENT FACILITY (	1,200.00 CY	-	-		276	79.31 /MH	21,879	21,879

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	EXCAVATION									
			EXCAVATION - ALLOWANCE FOR NEW DITCHES	REPLACES HAZMAT BLDG) AREA FILL	1,200.00 CY	-	-		276	79.31 /MH	21,879	21,879
			EXCAVATION						276		21,879	21,879
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL, ALLOWANCE FOR OLD DITCHES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	100.00 CY	-	-		17	79.31 /MH	1,367	1,367
			BACKFILL						17		1,367	1,367
		21.21.00	MASS FILL									
			MASS FILL, COMMON EARTH USING DUMP TRUCK, 2 MI ROUND TRIP, ALLWANCE FOR MISC ADDITIONAL FILL	RELOCATED BLDGS	1.00 LT	-	-	30,000	345	79.31 /MH	27,348	57,348
			MASS FILL					30,000	345		27,348	57,348
		21.39.00	STORM DRAINAGE UTILITIES									
			EXTEND CULVERTS UNDER ROAD	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	48.00 LF	-	-	4,800	166	79.31 /MH	13,127	17,927
			STORM DRAINAGE UTILITIES					4,800	166		13,127	17,927
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			EROSION AND SEDIMENTATION CONTROL - ALLOWANCE	RELOCATED BLDGS	1.00 LS	-	-	20,000	345	36.12 /MH	12,455	32,455
			EROSION AND SEDIMENTATION CONTROL					20,000	345		12,455	32,455
		21.43.00	FENCEWORK									
			FABRIC, WIRE & POSTS, CHAIN LINK FENCE, GALVANIZED, 6 FT TALL, 6 GAGE 3 STRANDS OF BARB WIRE, 2 IN POST AT 10 FT O.C.	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	800.00 FT	-	-	18,880	92	36.12 /MH	3,321	22,201
			VEHICLE GATE, 14 FT WIDE BY 7 FT TALL	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	4.00 EA	-	-	4,000	110	36.12 /MH	3,986	7,986
			FENCEWORK					22,880	202		7,307	30,187
		21.47.00	LANDSCAPING									
			LANDSCAPING - ALLOWANCE FOR PAVING GRADING & SEEDING	RELOCATED BLDGS	1.00 LS	-	-	40,000	460	36.12 /MH	16,607	56,607
			LANDSCAPING					40,000	460		16,607	56,607
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ASHPALT PAVING FOR TRUCK TURNAROUND , DRIVEWAY AND AROUND BLDG	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	43,000.00 SF	-	-	216,720	1,236	78.37 /MH	96,836	313,556
			ROAD, PARKING AREA, & SURFACED AREA					216,720	1,236		96,836	313,556
			CIVIL WORK					435,200	3,902		353,060	788,260
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	320.00 CY	-	-	73,600	2,575	59.71 /MH	153,736	227,336
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)- CONTAINER DISPOSAL SLAB & APRON	550.00 CY	-	-	126,500	4,425	59.71 /MH	264,234	390,734
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ACI PORT STAIRTOWER FDNS	60.00 CY	-	-	13,800	483	59.71 /MH	28,826	42,626
			CONCRETE					213,900	7,483		446,796	660,696
			CONCRETE					213,900	7,483		446,796	660,696
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	ACI PORT STAIR TOWERS AND PLATFORMS	728.00 SF	-	-	10,920	84	66.07 /MH	5,529	16,449
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	ACI PORT STAIR TOWERS AND PLATFORMS	436.00 LF	-	-	23,108	90	66.07 /MH	5,960	29,068
			STAIR SYSTEM	ACI PORT STAIR TOWERS AND PLATFORMS	896.00 SF	-	-	81,536	1,184	66.07 /MH	78,251	159,787
			GALLERY					115,564	1,358		89,740	205,304
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	UNIT 2 ACI PIPE RACK OVER ROADWAY, 35LF X 23 WIDE X 20' HIGH	1.26 TN	-	-	3,415	25	92.62 /MH	2,280	5,695

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			GIRDER					**3,415**	**25**		**2,280**	**5,695**
		23.25.00	**ROLLED SHAPE**									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	ACI PORT STAIRTOWER FRAMING - 2 TOWERS	4.40 TN	-	-	15,752	111	92.62 /MH	10,305	26,057
			REASSEMBLE ASH HANDLING/ELEC BLDG METAL FRAME, PURLINS & GIRTS AS NEW LABOR SHOP	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	50.00 TN	-	-		1,379	92.62 /MH	127,752	127,752
			ROLLED SHAPE					**15,752**	**1,491**		**138,057**	**153,809**
			STEEL					**134,731**	**2,873**		**230,077**	**364,808**
	24.00.00		**ARCHITECTURAL**									
		24.15.00	**DOOR (INCL. FRAME & HARDWARE)**									
			DOOR (INCL. FRAME & HARDWARE) - ROLL UP DOOR MAN DOOR ETC...	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			DOOR (INCL. FRAME & HARDWARE)					**5,000**	**92**		**4,699**	**9,699**
		24.27.00	**MASONRY**									
			BLOCK, CONCRETE, 8 IN, HOLLOW REINFORCED, ALTERNATE COURSES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	850.00 SF	-	-	4,242	106	53.08 /MH	5,601	9,842
			MASONRY					**4,242**	**106**		**5,601**	**9,842**
		24.35.00	**PRE-ENGINEERED BUILDING**									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	140,000	1,954	92.62 /MH	180,982	320,982
			PRE-ENGINEERED BUILDING					**140,000**	**1,954**		**180,982**	**320,982**
		24.37.00	**ROOFING**									
			METAL, INSULATED- NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	50,505	2,241	35.02 /MH	78,493	128,998
			ROOFING					**50,505**	**2,241**		**78,493**	**128,998**
		24.41.00	**SIDING**									
			METAL, INSULATED, NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	8,500.00 SF	-	-	140,760	870	79.59 /MH	69,207	209,967
			SIDING					**140,760**	**870**		**69,207**	**209,967**
		24.99.00	**ARCHITECTURAL, MISCELLANEOUS**									
			ARCHITECTURAL, MISCELLANEOUS - OFFICE ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	100,000	2,299	51.10 /MH	117,471	217,471
			ARCHITECTURAL, MISCELLANEOUS - TOOL CRIB	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			ARCHITECTURAL, MISCELLANEOUS					**105,000**	**2,391**		**122,170**	**227,170**
			ARCHITECTURAL					**445,507**	**7,653**		**461,151**	**906,658**
	27.00.00		**PAINTING & COATING**									
		27.17.00	**PAINTING**									
			PAINTING - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,025	23	47.61 /MH	1,108	3,133
			PAINTING					**2,025**	**23**		**1,108**	**3,133**
			PAINTING & COATING					**2,025**	**23**		**1,108**	**3,133**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.25.00	**CRANES & HOISTS**									
			BRIDGE CRANE - INSTALL SALVAGED 15 TN BRIDGE CRANE AND 2 JIB CRANES WITH EXISTING SUPPORT STEEL	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	21.00 TN	-	-	-	290	92.62 /MH	26,828	26,828
			BRIDGE CRANE - LOAD TEST & CERTIFY BRIDGE CRANE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 EA	-	-	-	230	92.62 /MH	21,292	21,292
			MOTORIZED HOIST - 1 TON	RELOCATED FROM PRESENT PORT LOCATIOIN	2.00 EA	-	-	-	138	68.48 /MH	9,446	9,446
			CRANES & HOISTS						**657**		**57,565**	**57,565**
		31.41.00	**FIRE PROTECTION EQUIPMENT & SYSTEM**									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LT	-	-	10,000	138	68.48 /MH	9,446	19,446
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	WASTE MANAGEMENT FACILITY (	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.41.00	**FIRE PROTECTION EQUIPMENT & SYSTEM**									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM					**37,500**	**523**		**35,814**	**73,314**
		31.51.00	**MERCURY REMOVAL EQUIPMENT**									
			ACTIVATED CARBON INJECTION (ACI) - LANCE RELOCATIONS	RELOCATED FROM PRESENT PORT LOCATIOIN (16 PER UNIT)	32.00 EA	-	-	-	368	68.48 /MH	25,188	25,188
			ACTIVATED CARBON INJECTION (ACI) - 40 HP BLOWERS	NEW BLOWERS (2 PER UNIT)	4.00 EA	-	-	80,000	184	68.48 /MH	12,594	92,594
			ACTIVATED CARBON INJECTION (ACI) - REMOVE EXISTING 20 HP BLOWERS	REMOVE EXISTING	2.00 EA	-	-	-	23	68.48 /MH	1,574	1,574
			MERCURY REMOVAL EQUIPMENT					**80,000**	**575**		**39,356**	**119,356**
			MECHANICAL EQUIPMENT					**117,500**	**1,755**		**132,736**	**250,236**
	34.00.00		**HVAC**									
		34.99.00	**HVAC, MISCELLANEOUS**									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS					**46,200**	**48**		**3,094**	**49,294**
			HVAC					**46,200**	**48**		**3,094**	**49,294**
	35.00.00		**PIPING**									
		35.13.25	**FRP, ABOVE GROUND, PROCESS AREA**									
			1.5 IN DIA, TAPER	INJECTION PORTS	12.00 LF	-	-	353	6	77.36 /MH	437	790
			2 IN DIA, TAPER	INJECTION PORTS	16.00 LF	-	-	421	9	77.36 /MH	697	1,118
			3 IN DIA, TAPER	INJECTION PORTS	40.00 LF	-	-	1,032	31	77.36 /MH	2,383	3,415
			FRP, ABOVE GROUND, PROCESS AREA					**1,806**	**45**		**3,518**	**5,323**
		35.14.25	**FRP, STRAIGHT RUN**									
			4 IN DIA, TAPER	NEW ACI PIPING	600.00 LF	-	-	12,660	400	77.36 /MH	30,944	43,604
			FRP, STRAIGHT RUN					**12,660**	**400**		**30,944**	**43,604**
		35.36.00	**PIPE SUPPORTS, RACK**									
			U-BOLT FOR 4 IN PIPE	ACI PIPE	27.00 EA	-	-	81	62	77.36 /MH	4,802	4,883
			SUPPORT SLEEPERS	ACI PIPE 330 LF	17.00 EA	-	-	5,950	78	77.36 /MH	6,047	11,997
			SUPPORT FOR 4 IN DIA PIPE - USER DEFINED		2.00 EA	-	-	306	18	77.36 /MH	1,423	1,729
			SUPPORT FOR 3 IN DIA PIPE - USER DEFINED		4.00 EA	-	-	576	32	77.36 /MH	2,490	3,066
			PIPE SUPPORTS, RACK					**6,913**	**191**		**14,761**	**21,674**
		35.45.00	**VALVES**									
			VALVE - 4" 150 LB CS GATE, FLANGED	ACI AUTO MATIC ISOLATION VALVES (RELOCATE 4 PER UNIT)	8.00 EA	-	-	160	66	77.36 /MH	5,122	5,282
			VALVES					**160**	**66**		**5,122**	**5,282**
			PIPING					**21,539**	**702**		**54,344**	**75,883**
	41.00.00		**ELECTRICAL EQUIPMENT**									
		41.37.00	**LIGHTING ACCESSORY (FIXTURE)**									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	71,500	75	63.63 /MH	4,754	76,254
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE)					**126,500**	**132**		**8,411**	**134,911**
		41.46.00	**MOTOR CONTROL CENTER (MCC), COMPONENT**									
			FVN STARTER - #4,	NEW BLOWERS	3.00 EA	-	-	14,700	55	63.63 /MH	3,511	18,211
			MOTOR CONTROL CENTER (MCC), COMPONENT					**14,700**	**55**		**3,511**	**18,211**
			ELECTRICAL EQUIPMENT					**141,200**	**187**		**11,921**	**153,121**
	42.00.00		**RACEWAY, CABLE TRAY & CONDUIT**									
		42.15.23	**CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY**									
			1-1/2 IN DIA, 3 FT LONG INCLUDING (2) CONNECTORS	NEW BLOWERS	3.00 EA	-	-	258	4	61.79 /MH	266	524
			CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY					**258**	**4**		**266**	**524**
		42.15.37	**CONDUIT, RGS**									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.15.37	CONDUIT, RGS									
			3/4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	HOIST	450.00 LF	-	-	1,319	100	61.79 /MH	6,200	7,519
			1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	NEW BLOWERS	400.00 LF	-	-	2,688	131	61.79 /MH	8,068	10,756
			CONDUIT, RGS					4,007	231		14,269	18,275
			RACEWAY, CABLE TRAY & CONDUIT					4,264	235		14,535	18,799
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC	ACI RELOCATION	600.00 LF	-	-	1,920	55	82.05 /MH	4,527	6,447
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					1,920	55		4,527	6,447
		43.20.00	600V CABLE & TERMINATION									
			600V #8 3/C CU EPR TS-CPE	HOIST	500.00 LF	-	-	3,280	14	82.05 /MH	1,179	4,459
			600V #4/0 3/C W/G CU EPR TS-CPE	NEW BLOWERS	450.00 LF	-	-	10,728	72	82.05 /MH	5,942	16,670
			TERMINATION - COMPRESSION LUG, #8, 2 HOLE, COPPER	HOIST	12.00 EA	-	-	78	4	82.05 /MH	340	418
			TERMINATION - COMPRESSION LUG, #4, 2 HOLE, COPPER	NEW BLOWERS	12.00 EA	-	-	111	7	82.05 /MH	566	677
			600V CABLE & TERMINATION					14,197	98		8,026	22,223
			CABLE					16,117	153		12,553	28,670
	44.00.00		CONTROL & INSTRUMENTATION									
		44.21.00	INSTRUMENT									
			ACCOUSTIC MONITOR	RELOCATE TO NEW INJECTION LANCES	6.00 EA	-	-		28	64.68 /MH	1,784	1,784
			INSTRUMENT						28		1,784	1,784
			CONTROL & INSTRUMENTATION						28		1,784	1,784
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			COMPUTATIONAL FLUID DYNAMIC ANALYSIS (CFD)	ACI SYSTEM	1.00 LS	100,000	-			/MH		100,000
			CONSULTANT, THIRD PARTY			100,000						100,000
			PROJECT INDIRECT			100,000						100,000
			190 DEMOLITION / RELOCATION			100,000		1,578,182	33,735		2,546,302	4,224,484
201			ELECTRICAL BOP SYSTEM									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	U1 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			2.5 FT DIA X 30 FT DEEP CAISSON	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	36.00 EA	-	-	66,852	910	108.46 /MH	98,736	165,588
			2.5 FT DIA X 30 FT DEEP CAISSON	BUS DUCT SUPPORTS	167.00 EA	-	-	310,119	4,223	108.46 /MH	458,025	768,144
			2.5 FT DIA X 30 FT DEEP CAISSON	OVERHEAD TRANSMISSION LINE STRUCTURAL - INCLUDES 115 KV DISCONNECT SWITCH FOUNDATION	10.00 EA	-	-	18,570	253	108.46 /MH	27,427	45,997
			2.5 FT DIA X 30 FT DEEP CAISSON	U2 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			CAISSON					480,963	6,549		710,351	1,191,314
			CIVIL WORK					480,963	6,549		710,351	1,191,314
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U1 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE FOUNDATIONS - COMPOSITE RATE	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BUS DUCT SUPPORTS	333.00 CY	-	-	76,590	2,679	59.71 /MH	159,982	236,572
			CONCRETE FOUNDATIONS - COMPOSITE RATE	OVERHEAD TRANSMISSION LINE STRUCTURAL	50.00 CY	-	-	11,500	402	59.71 /MH	24,021	35,521
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U2 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE					364,090	12,737		760,513	1,124,603
			CONCRETE					364,090	12,737		760,513	1,124,603
	23.00.00		STEEL									
		23.99.00	STEEL, MISCELLANEOUS									
			STEEL, MISCELLANEOUS - AUX SUPPORT STEEL	AUX SUPPORT STEEL	100.00 TN	-	-	271,000	1,954	92.62 /MH	180,982	451,982

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.99.00	STEEL, MISCELLANEOUS									
			STEEL, MISCELLANEOUS -	BUS DUCT SUPPORTS	167.00 TN	-	-	452,570	3,263	92.62 /MH	302,239	754,809
			STEEL, MISCELLANEOUS -	OVERHEAD TRANSMISSION LINE STRUCTURAL	15.00 TN	-	-	40,650	293	92.62 /MH	27,147	67,797
			STEEL, MISCELLANEOUS					764,220	5,510		510,368	1,274,588
			STEEL					764,220	5,510		510,368	1,274,588
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING				1,008,000		10,023		546,536	1,554,536
			ARCHITECTURAL				1,008,000		10,023		546,536	1,554,536
	41.00.00		ELECTRICAL EQUIPMENT									
		41.13.00	BUS DUCT									
			ISO PHASE, SELF COOLED	TAP BUS EXTENSIONS	200.00 LF	-	315,000		4,828	63.63 /MH	307,179	622,179
			NON SEGREGATED - (600V) (2000A) FGD ONLY		800.00 LF	-	588,000		5,517	63.63 /MH	351,062	939,062
			BUS DUCT				903,000		10,345		658,241	1,561,241
		41.45.00	MOTOR CONTROL CENTER (MCC), COMPLETE									
			MOTOR CONTROL CENTER (MCC), COMPLETE - 480V FGD		12.00 EA	-	636,000		5,931	63.63 /MH	377,392	1,013,392
			MOTOR CONTROL CENTER (MCC), COMPLETE				636,000		5,931		377,392	1,013,392
		41.51.00	POWER TRANSFORMER									
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	1.00 EA	-	875,000		1,379	63.63 /MH	87,766	962,766
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	1.00 EA	-	95,000			/MH		95,000
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	2.00 EA	-	1,700,000		2,759	63.63 /MH	175,531	1,875,531
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	2.00 EA	-	190,000			/MH		190,000
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 2000 KVA		4.00 EA	-	360,000		667	63.63 /MH	42,420	402,420
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 1500 KVA		4.00 EA	-	300,000		598	63.63 /MH	38,032	338,032
			POWER TRANSFORMER				3,520,000		5,402		343,748	3,863,748
		41.55.00	SWITCHGEAR, COMPLETE									
			480 V - REAGENT SWITCHGEAR		4.00 EA	-	212,000		1,977	63.63 /MH	125,797	337,797
			480 V - 480V FGD SWITCHGEAR		4.00 EA	-	840,000		4,138	63.63 /MH	263,297	1,103,297
			6.9 KV - SWITCHGEAR FGD		4.00 EA	-	1,680,000		14,713	63.63 /MH	936,166	2,616,166
			6.9 KV - SWITCHGEAR WALK IN TYPE		3.00 EA	-	660,000		5,810	63.63 /MH	369,712	1,029,712
			SWITCHGEAR, COMPLETE				3,392,000		26,638		1,694,972	5,086,972
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS AUX POWER EQUIPMENT		1.00 LT	-	2,840,000		11,494	63.63 /MH	731,379	3,571,379
			ELECTRICAL EQUIPMENT, MISCELLANEOUS				2,840,000		11,494		731,379	3,571,379
			ELECTRICAL EQUIPMENT				11,291,000		59,810		3,805,732	15,096,732
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.13.00	CABLE TRAY									
			CABLE TRAY - ALLOTMENT		1.00 LT	-	-	505,000	33,333	61.79 /MH	2,059,667	2,564,667
			CABLE TRAY					505,000	33,333		2,059,667	2,564,667
		42.15.37	CONDUIT, RGS									
			XX IN DIA - CONDUIT ALLOTMENT		1.00 LT	-	-	90,000	74,138	61.79 /MH	4,580,983	4,670,983
			CONDUIT, RGS					90,000	74,138		4,580,983	4,670,983
		42.18.00	DUCT BANK									

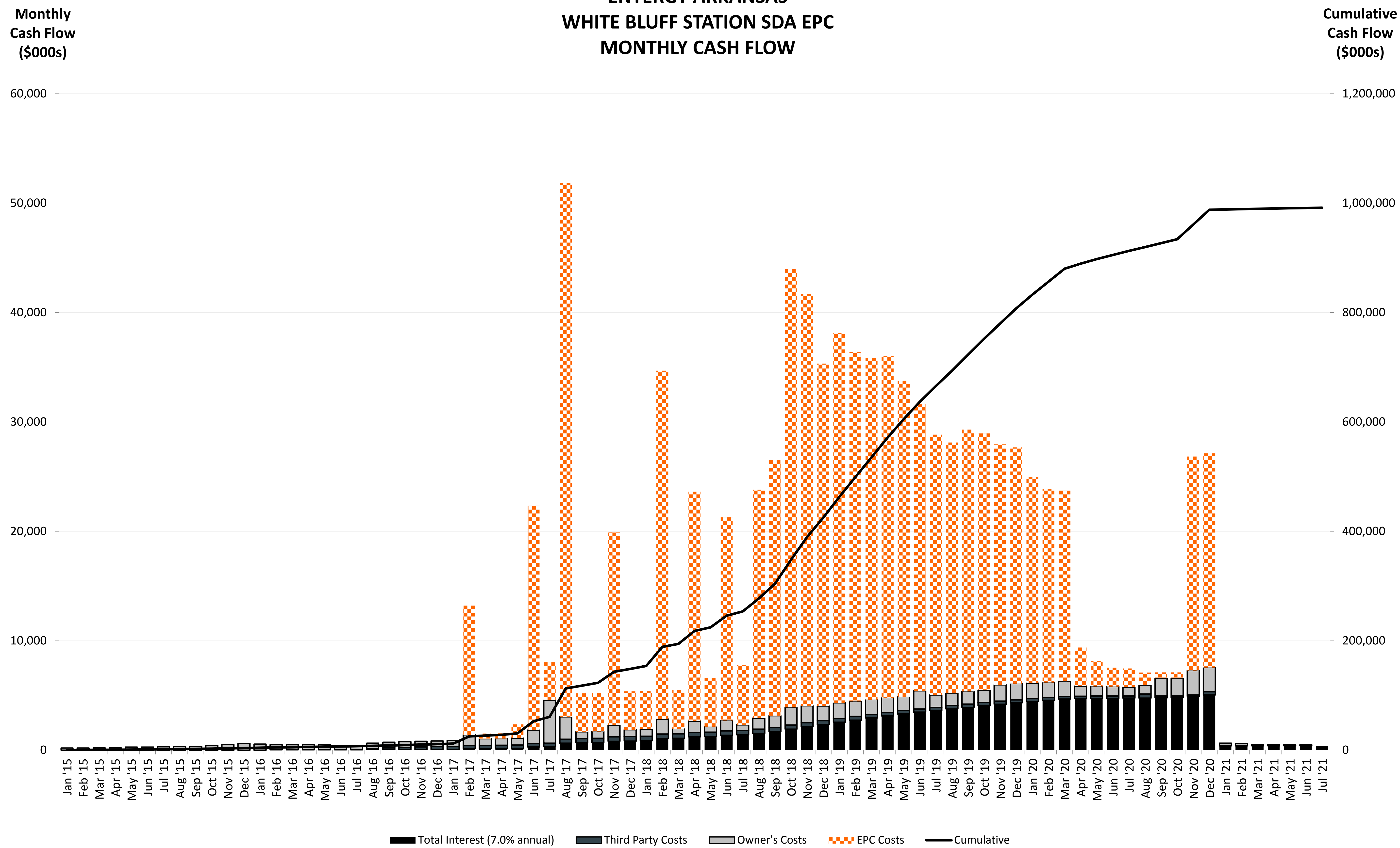
Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.18.00	DUCT BANK									
			DUCT BANK - UNDERGROUND DUCT BANKS NOT APPLICABLE		LT	-	-			61.79 /MH		
			RACEWAY, CABLE TRAY & CONDUIT					595,000	107,471		6,640,649	7,235,649
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC		201,600.00 LF	-	-	645,120	18,538	82.05 /MH	1,521,037	2,166,157
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					645,120	18,538		1,521,037	2,166,157
		43.20.00	600V CABLE & TERMINATION									
			600V CABLE - MISC		218,000.00 LF	-	-	1,881,340	30,069	82.05 /MH	2,467,159	4,348,499
			600V CABLE & TERMINATION					1,881,340	30,069		2,467,159	4,348,499
		43.40.00	5/8KV CABLE & TERMINATION									
			5/8KV #750 KCMIL 1/C CU EPR TS-CPE , FEEDS TO 8KV SWGR BLDG		225,000.00 LF	-	-	5,415,750	23,276	82.05 /MH	1,909,784	7,325,534
			5/8KV MISC		40,200.00 LF	-	-	297,480	10,628	82.05 /MH	871,993	1,169,473
			5/8KV CABLE & TERMINATION					5,713,230	33,903		2,781,778	8,495,008
		43.50.00	15KV CABLE & TERMINATION									
			15KV CABLE - MISC		22,300.00 LF	-	-	206,721	5,895	82.05 /MH	483,718	690,439
			15KV CABLE & TERMINATION					206,721	5,895		483,718	690,439
			CABLE					8,446,411	88,406		7,253,692	15,700,103
	51.00.00		SUBSTATION, SWITCHYARD & TRANSMISSION LINE									
		51.15.27	CIRCUIT BREAKER									
			CIRCUIT BREAKER - SWITCHYARD BAY AND 3 BREAKERS	ADDITION OF A SWITCHYARD BAY IS AVOIDED BY PLACING THE NEW SST NEXT TO THE EXISTING SST AND USING THE SAME OVERHEAD LINE.	0.00 LT	-				55.78 /MH		
		51.15.53	DISCONNECT SWITCH									
			115KV, 1200A, VERTICAL BREAK SWITCH WITH INSULATORS,INCLUDING GROUND SWITCH AND WITHOUT MOTORIZED OPERATOR	FOR ISOLATION OF RAT	1.00 EA	-	-	15,000	69	55.78 /MH	3,847	18,847
			DISCONNECT SWITCH					15,000	69		3,847	18,847
			SUBSTATION, SWITCHYARD & TRANSMISSION LINE					15,000	69		3,847	18,847
			201 ELECTRICAL BOP SYSTEM				12,299,000	10,665,684	290,576		20,231,688	43,196,372
211			INSTRUMENTATION AND CONTROLS BOP SYSTEM									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.13.00	CONTROL SYSTEM									
			DISTRIBUTED CONTROL SYSTEM (DCS) - I/O POINTS	ESTIMATED BOP 2000 I/O POINTS, (ANOTHER 1000 POINTS PER UNIT ARE INCLUDED IN THE DFGD PROPOSAL PRICES AND ARE NOT INCLUDED HERE)	1.00 LT	-	1,500,000		2,299	64.68 /MH	148,690	1,648,690
			CONTROL SYSTEM				1,500,000		2,299		148,690	1,648,690
		44.21.00	INSTRUMENT									
			INSTRUMENT - BOP INSTRUMENTS		1.00 LT	-	-	478,000	7,946	82.05 /MH	651,967	1,129,967
			INSTRUMENT - THERMOCOUPLES IN STACK ENTRANCE W ALARM		1.00 LT	-	-	100,000		82.05 /MH		100,000
			INSTRUMENT					578,000	7,946		651,967	1,229,967
		44.25.00	MONITORING EQUIPMENT									
			CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) - REFURBISHING		2.00 EA	-	-	460,000	625	64.68 /MH	40,444	500,444
			MONITORING EQUIPMENT - LOCAL HMI		3.00 EA	-	-	45,000	14	64.68 /MH	892	45,892

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			MONITORING EQUIPMENT					505,000	639		41,336	546,336
			CONTROL & INSTRUMENTATION				1,500,000	1,083,000	10,884		841,993	3,424,993
			211 INSTRUMENTATION AND CONTROLS				**1,500,000**	**1,083,000**	**10,884**		**841,993**	**3,424,993**
			BOP SYSTEM									

ATTACHMENT 2

Conceptual Capital Cost Estimate Cash Flow

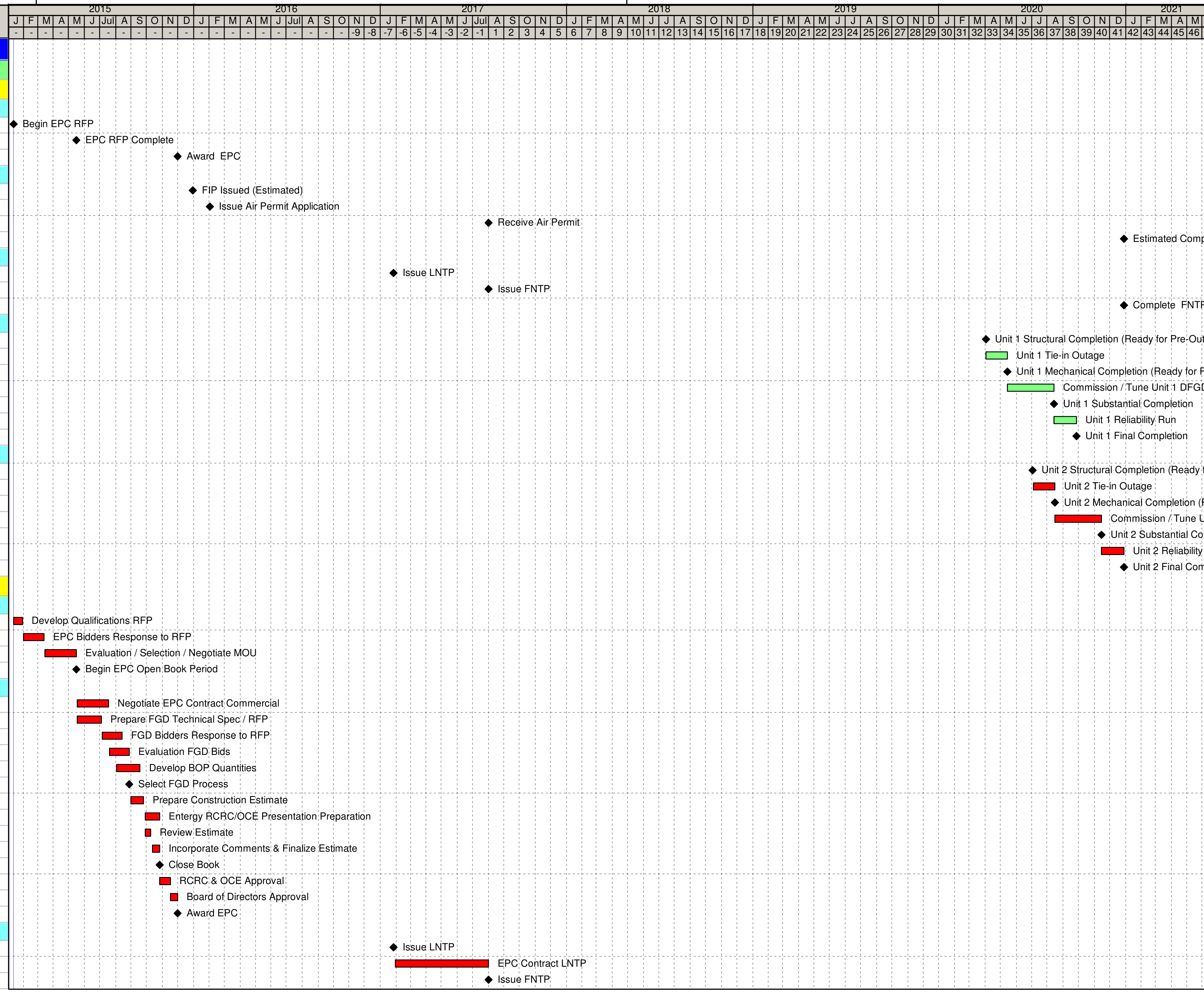
ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
MONTHLY CASH FLOW



ATTACHMENT 3

Level 1 Preliminary Execution Schedule

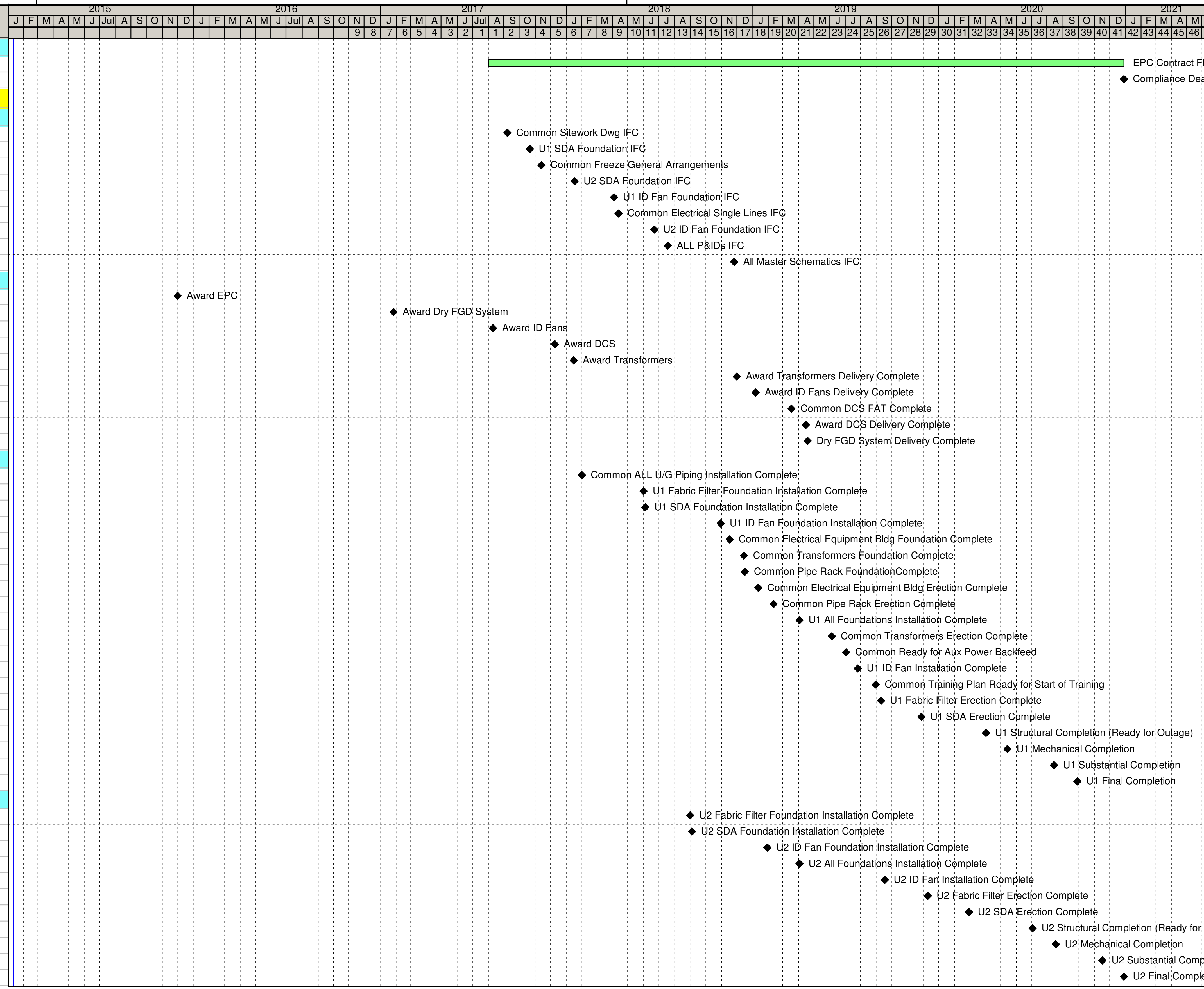
Activity ID	Activity Name	Ori Dur	Start	Finish
WHITE BLUFF FGD SCHEDULE (December 2020)		1556	13-Jan-15	29-Dec-20
Milestones		1556	13-Jan-15	29-Dec-20
Project Milestones		1556	13-Jan-15	29-Dec-20
EPC RFP		225	13-Jan-15	30-Nov-15
MS010	Begin EPC RFP	0	13-Jan-15	
MS100	EPC RFP Complete	0		15-May-15
MS225	Award EPC	0		30-Nov-15
Permitting		1272	30-Dec-15	29-Dec-20
MS275	FIP Issued (Estimated)	0		30-Dec-15
MS015	Issue Air Permit Application	0		02-Feb-16
MS020	Receive Air Permit	0		31-Jul-17
MS285	Estimated Compliance Date	0		29-Dec-20
LNTP/FNTP		998	27-Jan-17	28-Dec-20
MS260	Issue LNTP	0		27-Jan-17
MS030	Issue FNTP	0		31-Jul-17
MS265	Complete FNTP Period	0		28-Dec-20
Unit 1 & Common Outage, Start-Up & Commissioning		178	02-Apr-20	27-Sep-20
MS0100	Unit 1 Structural Completion (Ready for Pre-Outage)	0		02-Apr-20
MS0110	Unit 1 Tie-in Outage	42	03-Apr-20	14-May-20
MS0120	Unit 1 Mechanical Completion (Ready for Flue Gas)	0		14-May-20
MS0130	Commission / Tune Unit 1 DFGD System	91	15-May-20	13-Aug-20
MS0140	Unit 1 Substantial Completion	0		13-Aug-20
MS0150	Unit 1 Reliability Run	45	14-Aug-20	27-Sep-20
MS0160	Unit 1 Final Completion	0		27-Sep-20*
Unit 2 Outage, Start-Up & Commissioning		179	03-Jul-20	29-Dec-20
MS0200	Unit 2 Structural Completion (Ready for Pre-Outage)	0		03-Jul-20
MS0210	Unit 2 Tie-in Outage	43	04-Jul-20	15-Aug-20
MS0220	Unit 2 Mechanical Completion (Ready for Flue Gas)	0		15-Aug-20
MS0230	Commission / Tune Unit 2 DFGD System	91	16-Aug-20	14-Nov-20
MS0240	Unit 2 Substantial Completion	0		14-Nov-20
MS0250	Unit 2 Reliability Run	45	15-Nov-20	29-Dec-20
MS0260	Unit 2 Final Completion	0		29-Dec-20
Project Overview		1556	13-Jan-15	29-Dec-20
EPC RFP		89	13-Jan-15	15-May-15
OV1000	Develop Qualifications RFP	14	13-Jan-15	30-Jan-15
OV1010	EPC Bidders Response to RFP	30	02-Feb-15	13-Mar-15
OV1020	Evaluation / Selection / Negotiate MOU	45	16-Mar-15	15-May-15
OV1040	Begin EPC Open Book Period	0		15-May-15
EPC Development Phase		141	18-May-15	30-Nov-15
OV1030	Negotiate EPC Contract Commercial	45	18-May-15	17-Jul-15
OV1050	Prepare FGD Technical Spec / RFP	35	18-May-15	03-Jul-15
OV1060	FGD Bidders Response to RFP	30	06-Jul-15	14-Aug-15
OV1070	Evaluation FGD Bids	30	20-Jul-15	28-Aug-15
OV1090	Develop BOP Quantities	35	03-Aug-15	18-Sep-15
OV1080	Select FGD Process	0		28-Aug-15
OV1100	Prepare Construction Estimate	20	31-Aug-15	25-Sep-15
OV1110	Entergy RCRC/OCE Presentation Preparation	21	28-Sep-15	26-Oct-15
OV1103	Review Estimate	10	28-Sep-15	09-Oct-15
OV1105	Incorporate Comments & Finalize Estimate	11	12-Oct-15	26-Oct-15
OV1120	Close Book	0		26-Oct-15
OV1130	RCRC & OCE Approval	15	27-Oct-15	16-Nov-15
OV1140	Board of Directors Approval	10	17-Nov-15	30-Nov-15
OV1145	Award EPC	0		30-Nov-15
LNTP		132	27-Jan-17	01-Aug-17
OV1150	Issue LNTP	0		27-Jan-17
OV1160	EPC Contract LNTP	132	30-Jan-17	01-Aug-17
OV1170	Issue FNTP	0		01-Aug-17



Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

Activity ID	Activity Name	Orig Dur	Start	Finish
FNTP		890	02-Aug-17	29-Dec-20
OV1180	EPC Contract FNTP Period	889	02-Aug-17	28-Dec-20
OV1230	Compliance Deadline	0		29-Dec-20*
EPC Milestones		1292	30-Nov-15	29-Dec-20
Engineering		308	07-Sep-17	26-Nov-18
EPC325	Common Sitework Dwg IFC	0		07-Sep-17
EPC345	U1 SDA Foundation IFC	0		20-Oct-17
EPC340	Common Freeze General Arrangements	0		13-Nov-17
EPC510	U2 SDA Foundation IFC	0		16-Jan-18
EPC350	U1 ID Fan Foundation IFC	0		03-Apr-18
EPC320	Common Electrical Single Lines IFC	0		13-Apr-18
EPC485	U2 ID Fan Foundation IFC	0		22-Jun-18
EPC355	ALL P&IDs IFC	0		18-Jul-18
EPC240	All Master Schematics IFC	0		26-Nov-18
Procurement		858	30-Nov-15	19-Apr-19
EPC010	Award EPC	0		30-Nov-15
EPC100	Award Dry FGD System	0		27-Jan-17
EPC110	Award ID Fans	0		09-Aug-17
EPC335	Award DCS	0		08-Dec-17
EPC315	Award Transformers	0		15-Jan-18
EPC545	Award Transformers Delivery Complete	0		30-Nov-18
EPC535	Award ID Fans Delivery Complete	0		07-Jan-19
EPC415	Common DCS FAT Complete	0		18-Mar-19
EPC540	Award DCS Delivery Complete	0		15-Apr-19
EPC530	Dry FGD System Delivery Complete	0		19-Apr-19
Unit 1 & Common Construction & Commissioning		677	30-Jan-18	28-Sep-20
EPC425	Common ALL U/G Piping Installation Complete	0		30-Jan-18
EPC370	U1 Fabric Filter Foundation Installation Complete	0		01-Jun-18
EPC360	U1 SDA Foundation Installation Complete	0		05-Jun-18
EPC365	U1 ID Fan Foundation Installation Complete	0		30-Oct-18
EPC395	Common Electrical Equipment Bldg Foundation Complete	0		16-Nov-18
EPC405	Common Transformers Foundation Complete	0		14-Dec-18
EPC460	Common Pipe Rack FoundationComplete	0		17-Dec-18
EPC400	Common Electrical Equipment Bldg Erection Complete	0		11-Jan-19
EPC390	Common Pipe Rack Erection Complete	0		11-Feb-19
EPC310	U1 All Foundations Installation Complete	0		02-Apr-19
EPC410	Common Transformers Erection Complete	0		05-Jun-19
EPC435	Common Ready for Aux Power Backfeed	0		02-Jul-19
EPC380	U1 ID Fan Installation Complete	0		25-Jul-19
EPC420	Common Training Plan Ready for Start of Training	0		29-Aug-19
EPC385	U1 Fabric Filter Erection Complete	0		09-Sep-19
EPC375	U1 SDA Erection Complete	0		28-Nov-19
EPC440	U1 Structural Completion (Ready for Outage)	0		02-Apr-20
EPC445	U1 Mechanical Completion	0		14-May-20
EPC450	U1 Substantial Completion	0		13-Aug-20
EPC455	U1 Final Completion	0		28-Sep-20
Unit 2 Construction & Commissioning		593	31-Aug-18	29-Dec-20
EPC475	U2 Fabric Filter Foundation Installation Complete	0		31-Aug-18
EPC515	U2 SDA Foundation Installation Complete	0		04-Sep-18
EPC490	U2 ID Fan Foundation Installation Complete	0		29-Jan-19
EPC465	U2 All Foundations Installation Complete	0		02-Apr-19
EPC495	U2 ID Fan Installation Complete	0		16-Sep-19
EPC470	U2 Fabric Filter Erection Complete	0		09-Dec-19
EPC505	U2 SDA Erection Complete	0		28-Feb-20
EPC520	U2 Structural Completion (Ready for Outage)	0		03-Jul-20
EPC500	U2 Mechanical Completion	0		17-Aug-20
EPC525	U2 Substantial Completion	0		16-Nov-20
EPC480	U2 Final Completion	0		29-Dec-20



Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

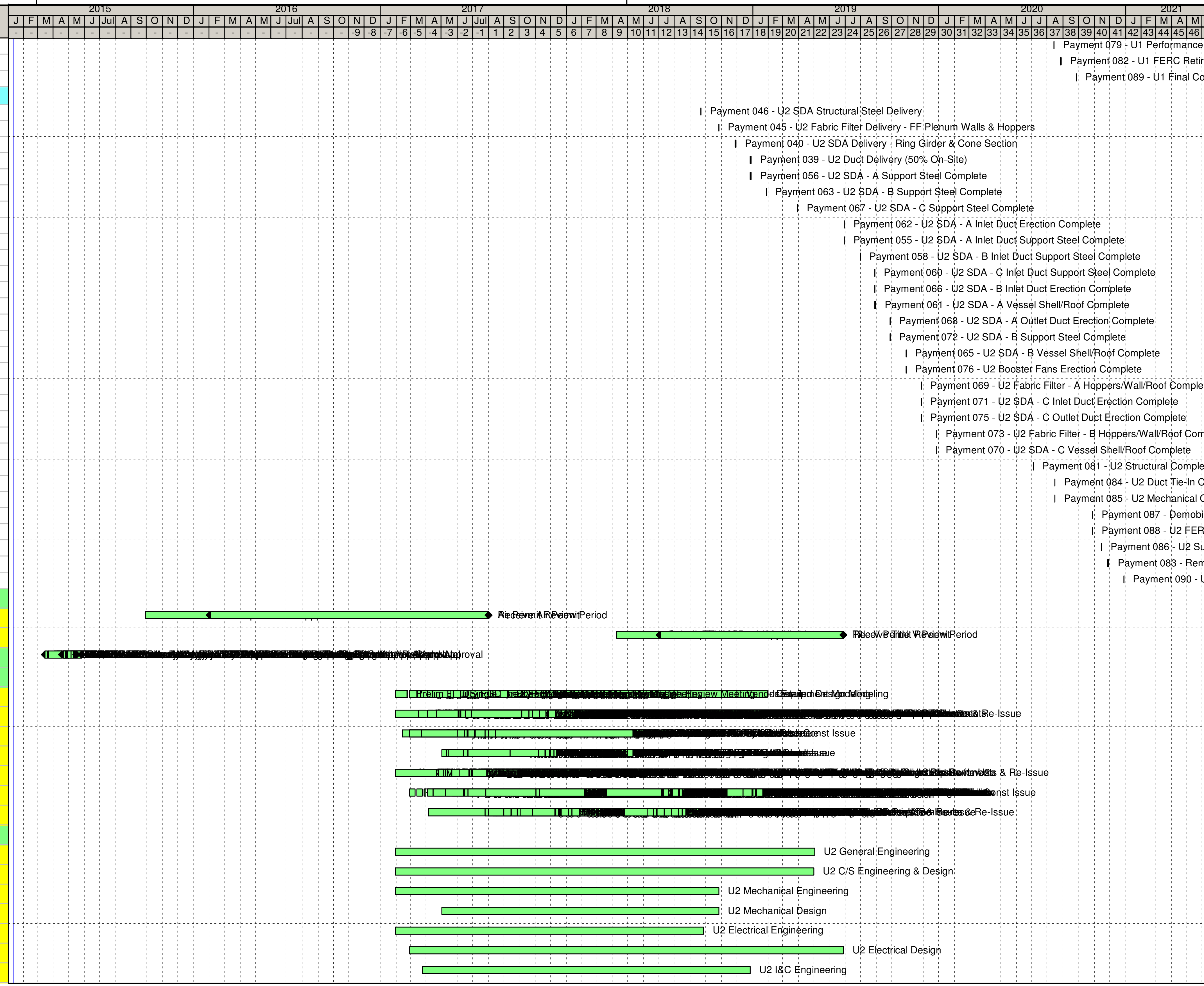
TASK filter: Exclude WBS Activities_1.

Activity ID	Activity Name	Ori Dur	Start	Finish
Payment Milestones		1401	28-Feb-17	29-Dec-20
Unit 1 & Common		1308	28-Feb-17	27-Sep-20
PAY001	Payment 001 - DFGD Award	1	28-Feb-17	28-Feb-17
PAY002	Payment 002 - Initial Design Info from DFGD Supplier - Flow ...	1	29-Mar-17	29-Mar-17
PAY003	Payment 003 - Parent Company Guarantee Document	1	30-Mar-17	30-Mar-17
PAY004	Payment 004 - Initial Design Info from DFGD Supplier - P&IDs...	1	28-Apr-17	28-Apr-17
PAY006	Payment 006 - NTE Load Diagrams for SDA & FF	1	28-Apr-17	28-Apr-17
PAY008	Payment 008 - Initial Design Info from DFGD Supplier - 1st Iss...	1	28-Apr-17	28-Apr-17
PAY005	Payment 005 - Project Specific GA's - Issued for Owner Rvw	1	25-May-17	25-May-17
PAY013	Payment 013 - Initial Design Info from DFGD Supplier - Projec...	1	25-May-17	25-May-17
PAY009	Payment 009 - FERC Retirement Information - Preliminary	1	30-Jun-17	30-Jun-17
PAY011	Payment 011 - Award Atomizers	1	31-Jul-17	31-Jul-17
PAY007	Payment 007 - Award ID Booster Fans	1	22-Aug-17	22-Aug-17
PAY015	Payment 015 - NTE Load Diagrams - Lime Storage & Prep Sy...	1	22-Aug-17	22-Aug-17
PAY027	Payment 027 - Receive Permits for Construction - Req'd Tier ...	1	25-Aug-17	25-Aug-17
PAY028	Payment 028 - Mobilize On Site	1	26-Aug-17	26-Aug-17
PAY012	Payment 012 - Award Lime System	1	28-Aug-17	28-Aug-17
PAY014	Payment 014 - Flue Gas Ductwork Procurement Initiated - PO...	1	28-Sep-17	28-Sep-17
PAY030	Payment 030 - Office Complex & Fab Areas Set-Up - Office Tr...	1	28-Sep-17	28-Sep-17
PAY016	Payment 016 - Initial EI&C Design Info - Project Specific Proc...	1	24-Oct-17	24-Oct-17
PAY010	Payment 010 - NTE Load Diagrams - ID Booster Fans	1	22-Nov-17	22-Nov-17
PAY017	Payment 017 - Flue Gas Ductwork Procurement Initiated - U1 ...	1	28-Nov-17	28-Nov-17
PAY018	Payment 018 - Structural Steel Procurement - SDA Support St...	1	26-Dec-17	27-Dec-17
PAY022	Payment 022 - Award DCS	1	26-Dec-17	27-Dec-17
PAY024	Payment 024 - Flue Gas Ductwork Start Fab - Ductwork	1	26-Dec-17	27-Dec-17
PAY019	Payment 019 - Strucutural Steel Fab Sched - Schedule for Fa...	1	26-Jan-18	26-Jan-18
PAY020	Payment 020 - SDA Design Dwgs - SDA Access Steel Dwgs (...	1	28-Feb-18	28-Feb-18
PAY021	Payment 021 - Fabric Filter Design Dwgs - Fabric Filter Acces...	1	28-Feb-18	28-Feb-18
PAY023	Payment 023 - Award Fabric Filter Bags & Cages	1	30-Apr-18	30-Apr-18
PAY025	Payment 025 - Structural Steel Start Fab - Steel Members	1	30-May-18	30-May-18
PAY026	Payment 026 - Design Info from DFGD Supplier - Physical Flo...	1	30-Jun-18	30-Jun-18
PAY033	Payment 033 - U1 Fabric Filter Delivery - FF Plenum Walls & ...	1	30-Jun-18	30-Jun-18
PAY034	Payment 034 - U1 SDA Structural Steel Delivery	1	30-Jun-18	30-Jun-18
PAY035	Payment 035 - U1 Duct Delivery (50% On-Site)	1	25-Jul-18	25-Jul-18
PAY032	Payment 032 - Lime Storage & Prep Sys Delivery - Silos, Tan...	1	23-Aug-18	23-Aug-18
PAY029	Payment 029 - U1 SDA Delivery - Ring Girder & Cone Section	1	28-Sep-18	28-Sep-18
PAY036	Payment 036 - U1 SDA - A Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY042	Payment 042 - U1 SDA - C Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY037	Payment 037 - U1 SDA - A Duct Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY038	Payment 038 - U1 Fabric Filter Struct Steel Delivery - Grid Ste...	1	28-Dec-18	28-Dec-18
PAY031	Payment 031 - U1 & U2 Booster Fan Delivery - Fans-Motors-L...	1	26-Jan-19	26-Jan-19
PAY041	Payment 041 - U1 SDA - A Inlet Duct Erection Complete	1	30-Apr-19	30-Apr-19
PAY043	Payment 043 - U1 SDA - A Outlet Duct Erection Complete	1	30-May-19	30-May-19
PAY054	Payment 054 - DCS Equipment Delivery	1	28-Jun-19	28-Jun-19
PAY044	Payment 044 - U1 SDA - A Vessel Shell/Roof Complete	1	29-Jun-19	29-Jun-19
PAY047	Payment 047 - U1 SDA - B Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY049	Payment 049 - U1 SDA - B Outlet Duct Erection Complete	1	31-Jul-19	31-Jul-19
PAY057	Payment 057 - U1 Booster Fans Erection Complete	1	01-Aug-19	01-Aug-19
PAY051	Payment 051 - U1 SDA - C Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY052	Payment 052 - U1 SDA - C Outlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY048	Payment 048 - U1 SDA - B Vessel Shell/Roof Complete	1	27-Sep-19	27-Sep-19
PAY050	Payment 050 - U1 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY059	Payment 059 - U1 Fabric Filter - C Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY064	Payment 064 - Operating & Maintenance Manuals	1	28-Sep-19	28-Sep-19
PAY053	Payment 053 - U1 SDA - C Vessel Shell/Roof Complete	1	28-Nov-19	28-Nov-19
PAY074	Payment 074 - U1 Structural Completion	1	02-Apr-20	02-Apr-20
PAY077	Payment 077 - U1 Duct Tie-In Complete	1	29-Apr-20	29-Apr-20
PAY078	Payment 078 - U1 Mechanical Completion	1	15-May-20	15-May-20
PAY080	Payment 080 - U1 Substantial Completion	1	13-Aug-20	13-Aug-20

Remaining Work | Actual Work | WBS Summary | Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

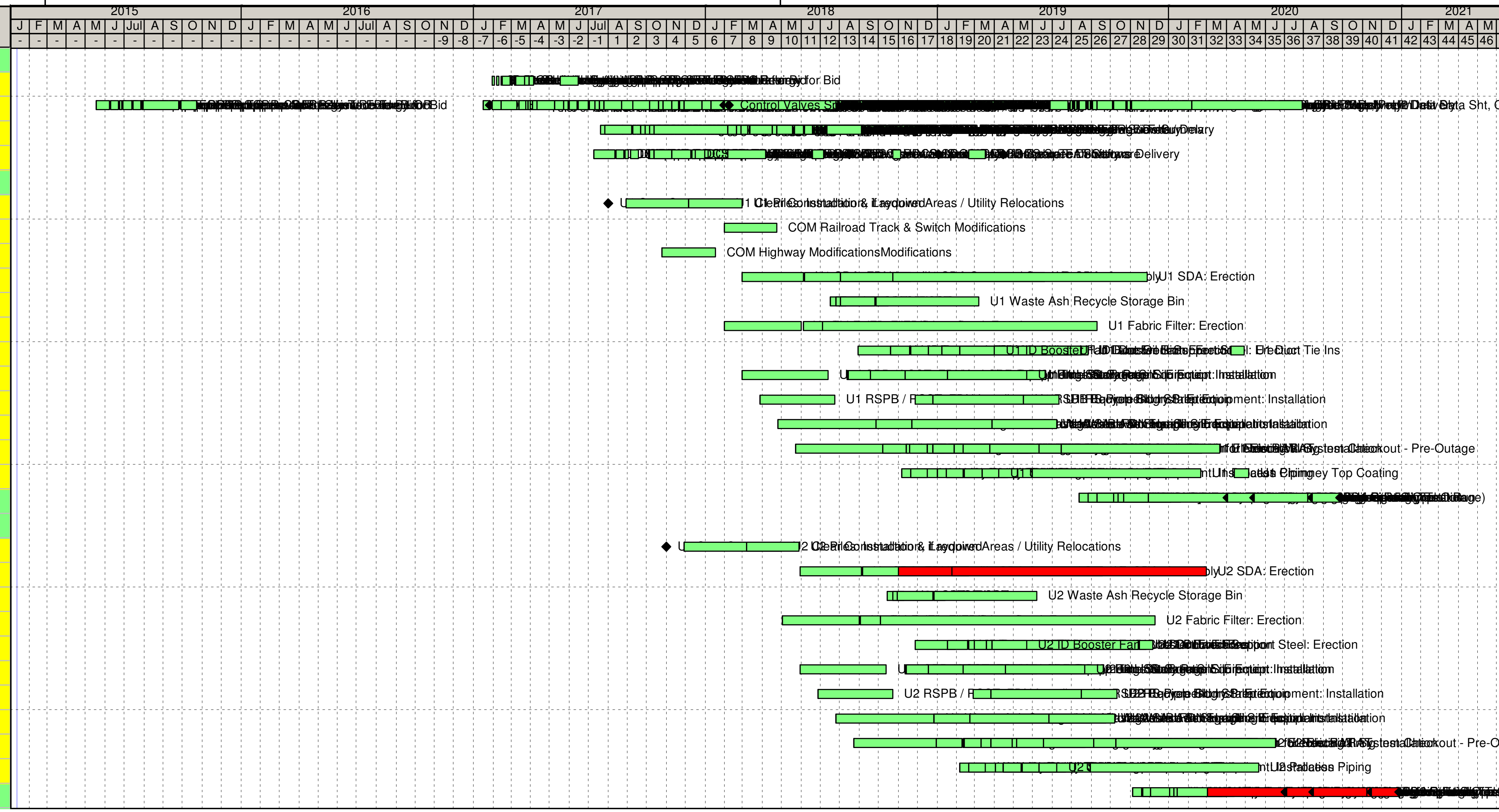
Activity ID	Activity Name	Orig Dur	Start	Finish
PAY079	Payment 079 - U1 Performance Test Report	1	14-Aug-20	14-Aug-20
PAY082	Payment 082 - U1 FERC Retirement Information	1	27-Aug-20	27-Aug-20
PAY089	Payment 089 - U1 Final Completion	1	27-Sep-20	27-Sep-20
Unit 2		830	22-Sep-18	29-Dec-20
PAY046	Payment 046 - U2 SDA Structural Steel Delivery	1	22-Sep-18	22-Sep-18
PAY045	Payment 045 - U2 Fabric Filter Delivery - FF Plenum Walls & ...	1	27-Oct-18	27-Oct-18
PAY040	Payment 040 - U2 SDA Delivery - Ring Girder & Cone Section	1	28-Nov-18	28-Nov-18
PAY039	Payment 039 - U2 Duct Delivery (50% On-Site)	1	28-Dec-18	28-Dec-18
PAY056	Payment 056 - U2 SDA - A Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY063	Payment 063 - U2 SDA - B Support Steel Complete	1	28-Jan-19	28-Jan-19
PAY067	Payment 067 - U2 SDA - C Support Steel Complete	1	30-Mar-19	30-Mar-19
PAY062	Payment 062 - U2 SDA - A Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY055	Payment 055 - U2 SDA - A Inlet Duct Support Steel Complete	1	30-Jun-19	30-Jun-19
PAY058	Payment 058 - U2 SDA - B Inlet Duct Support Steel Complete	1	31-Jul-19	31-Jul-19
PAY060	Payment 060 - U2 SDA - C Inlet Duct Support Steel Complete	1	28-Aug-19	28-Aug-19
PAY066	Payment 066 - U2 SDA - B Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY061	Payment 061 - U2 SDA - A Vessel Shell/Roof Complete	1	29-Aug-19	29-Aug-19
PAY068	Payment 068 - U2 SDA - A Outlet Duct Erection Complete	1	27-Sep-19	27-Sep-19
PAY072	Payment 072 - U2 SDA - B Support Steel Complete	1	27-Sep-19	27-Sep-19
PAY065	Payment 065 - U2 SDA - B Vessel Shell/Roof Complete	1	29-Oct-19	29-Oct-19
PAY076	Payment 076 - U2 Booster Fans Erection Complete	1	29-Oct-19	29-Oct-19
PAY069	Payment 069 - U2 Fabric Filter - A Hoppers/Wall/Roof Complete	1	28-Nov-19	28-Nov-19
PAY071	Payment 071 - U2 SDA - C Inlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY075	Payment 075 - U2 SDA - C Outlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY073	Payment 073 - U2 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Dec-19	27-Dec-19
PAY070	Payment 070 - U2 SDA - C Vessel Shell/Roof Complete	1	28-Dec-19	28-Dec-19
PAY081	Payment 081 - U2 Structural Completion	1	04-Jul-20	04-Jul-20
PAY084	Payment 084 - U2 Duct Tie-In Complete	1	16-Aug-20	16-Aug-20
PAY085	Payment 085 - U2 Mechanical Completion	1	16-Aug-20	16-Aug-20
PAY087	Payment 087 - Demobilization Complete	1	28-Oct-20	28-Oct-20
PAY088	Payment 088 - U2 FERC Retirement Information	1	28-Oct-20	28-Oct-20
PAY086	Payment 086 - U2 Substantial Completion	1	15-Nov-20	15-Nov-20
PAY083	Payment 083 - Removal of Fabrication Tables Complete	1	28-Nov-20	28-Nov-20
PAY090	Payment 090 - U2 Final Completion	1	29-Dec-20	29-Dec-20
Permitting		949	29-Sep-15	27-Jun-19
Air Permit		465	29-Sep-15	31-Jul-17
Title V Operating Permit		310	09-Apr-18	27-Jun-19
TRAX Boiler Pressure Analysis		81	16-Mar-15	08-Jul-15
U1 Engineering		540	30-Jan-17	15-Mar-19
U1 General Engineering & Design		507	30-Jan-17	29-Jan-19
U1 C/S/A Engineering and Design		500	30-Jan-17	18-Jan-19
U1 Mechanical Engineering		364	13-Feb-17	18-Jul-18
U1 Mechanical Design		309	01-May-17	18-Jul-18
U1 Electrical Engineering		344	30-Jan-17	05-Jun-18
U1 Electrical Design		520	27-Feb-17	15-Mar-19
U1 I&C Engineering		368	06-Apr-17	17-Sep-18
U2 Engineering		630	30-Jan-17	28-Jun-19
U2 General Engineering & Design		590	30-Jan-17	03-May-19
U2 C/S/A Engineering and Design		587	30-Jan-17	30-Apr-19
U2 Mechanical Engineering		455	30-Jan-17	26-Oct-18
U2 Mechanical Design		389	02-May-17	26-Oct-18
U2 Electrical Engineering		434	30-Jan-17	27-Sep-18
U2 Electrical Design		610	27-Feb-17	28-Jun-19
U2 I&C Engineering		460	24-Mar-17	27-Dec-18



Remaining Work · Actual Work · WBS Summary
Critical Remaining Work · Milestone

TASK filter: Exclude WBS Activities_1.

Activity ID	Activity Name	Ori Dur	Start	Finish
	Procurement	1357	18-May-15	28-Jul-20
	C/S/A Procurement	98	30-Jan-17	15-Jun-17
	Mechanical Procurement	1357	18-May-15	28-Jul-20
	Electrical Procurement	347	20-Jul-17	30-Nov-18
	I&C Procurement	448	10-Jul-17	15-Apr-19
	U1 Construction	720	02-Aug-17	05-May-20
	U1 Sitework	150	02-Aug-17	27-Feb-18
	U1 Railroad Track & Switch Mods	60	31-Jan-18	24-Apr-18
	U1 Highway Mods	60	25-Oct-17	16-Jan-18
	U1 SDA	457	28-Feb-18	28-Nov-19
	U1 Field Fabricated Tanks	170	16-Jul-18	08-Mar-19
	U1 Fabric Filter	419	31-Jan-18	09-Sep-19
	U1 ID Booster Fans / Ductwork	436	29-Aug-18	29-Apr-20
	U1 Lime Slurry	343	28-Feb-18	21-Jun-19
	U1 Recycle Slurry	337	29-Mar-18	12-Jul-19
	U1 Byproduct Handling	314	25-Apr-18	08-Jul-19
	U1 Auxiliary Power	478	23-May-18	20-Mar-20
	U1 Balance of Plant	390	07-Nov-18	05-May-20
	U1 System Testing and Commissioning	294	13-Aug-19	27-Sep-20
	U2 Construction	686	01-Nov-17	17-Jun-20
	U2 Sitework	150	01-Nov-17	29-May-18
	U2 SDA	458	30-May-18	28-Feb-20
	U2 Field Fabricated Tanks	170	15-Oct-18	07-Jun-19
	U2 Fabric Filter	419	02-May-18	09-Dec-19
	U2 ID Booster Fans / Ductwork	268	28-Nov-18	07-Dec-19
	U2 Lime Slurry	343	30-May-18	20-Sep-19
	U2 Recycle Slurry	337	28-Jun-18	11-Oct-19
	U2 Byproduct Handling	314	25-Jul-18	07-Oct-19
	U2 Auxiliary Power	476	22-Aug-18	17-Jun-20
	U2 Balance of Plant	337	06-Feb-19	21-May-20
	U2 System Testing and Commissioning	301	05-Nov-19	29-Dec-20



Remaining Work
Critical Remaining Work
Actual Work
Milestone
WBS Summary

TASK filter: Exclude WBS Activities_1.

ATTACHMENT 4

Milestone Progress Payment Schedule

Attachment 4

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
1	Feb-17	Award Dry FGD Contract Execution	1.51	1.51
2	Mar-17	DFGD Supplier - Process Flow Diagrams and Mass Balances	0.06	1.57
3	Apr-17	DFGD Supplier - P&ID Drawings	0.06	1.63
4	May-17	DFGD Supplier - General Arrangement Drawings NTE Load Diagrams	0.16	1.79
5	Jun-17	DFGD Supplier - Preliminary 3D CAD Model Award Booster Fans	2.62	4.41
6	Jul-17	NTE Load Diagrams Award Atomizers	0.45	4.86
7	Aug-17	DFGD Supplier - Equipment Lists Award Lime System	6.24	11.10
8	Sep-17	Flue Gas Ductwork Procurement Initiated	0.45	11.55
9	Oct-17	Initial EI&C Design Information NTE Load Diagrams	0.45	12.00
10	Nov-17	Flue Gas Ductwork Procurement Initiated	2.26	14.26
11	Dec-17	Structural Steel Procurement Initiated	0.45	14.71
12	Jan-18	Structural Steel Fabrication Schedule Complete	0.45	15.16
13	Feb-18	SDA and Fabric Filter Design Drawings	4.07	19.23
14	Mar-18	Award DCS	0.45	19.68
15	Apr-18	Award Fabric Filter Bags and Cages Flue Gas Ductwork Start of Fabrication	2.68	22.36
16	May-18	Structural Steel Start of Fabrication	0.57	22.93
17	Jun-18	Physical Flow Model Completed	2.38	25.31
18	Jul-18	Receive Permits for Construction	0.70	26.01
19	Aug-18	Mobilize On-Site	2.67	28.68
20	Sep-18	Unit 1 SDA Delivery Office Complex and Fabrication Areas Set-Up	2.99	31.67
21	Oct-18	Unit 1 and Unit 2 Booster Fan Delivery Lime Storage and Preparation System Delivery Unit 1 Fabric Filter Delivery	5.12	36.79
22	Nov-18	Unit 1 SDA Structural Steel Delivery Unit 1 Duct Delivery Unit 1 SDA-A Support Steel Erection Complete	4.81	41.60
23	Dec-18	Unit 1 SDA-A Inlet Duct Support Steel Complete Unit 1 Fabric Filter Structural Steel Delivery Unit 2 Duct Delivery	4.00	45.60
24	Jan-19	Unit 2 SDA Delivery Unit 1 SDA-A Inlet Duct Erection Complete Unit 1 SDA-C Support Steel Erection Complete	4.32	49.92
25	Feb-19	Unit 1 SDA-A Outlet Duct Erection Complete Unit 1 SDA-A Vessel Shell/Roof Complete Unit 2 Fabric Filter Delivery	4.08	54.00
26	Mar-19	Unit 2 Structural Steel Delivery Unit 1 SDA-B Inlet Duct Erection Complete Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete	3.99	57.99

Attachment 4

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
27	Apr-19	Unit 1 SDA-B Vessel Shell/Roof Complete	3.99	61.98
		Unit 1 SDA-B Outlet Duct Erection Complete		
		Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete		
28	May-19	Unit 1 SDA-C Inlet Duct Erection Complete	3.69	65.67
		Unit 1 SDA-C Outlet Duct Erection Complete		
29	Jun-19	Unit 1 SDA-C Vessel Shell/Roof Complete	3.35	69.02
		DCS Equipment Delivery		
		Unit 2 SDA-A Inlet Duct Support Steel Complete		
		Unit 2 SDA-A Support Steel Complete		
30	Jul-19	Unit 1 Booster Fans Erection Complete	3.04	72.06
		Unit 2 SDA-B Inlet Duct Support Steel Complete		
		Unit 1 Fabric Filter-C Hoppers/Wall/Roof Complete		
31	Aug-19	Unit 2 SDA-C Inlet Duct Support Steel Complete	2.93	74.99
		Unit 2 SDA-A Vessel Shell/Roof Complete		
		Unit 2 SDA-A Inlet Duct Erection Complete		
32	Sep-19	Unit 2 SDA-B Support Steel Complete	3.06	78.05
		Operating and Maintenance Manuals		
33	Oct-19	Unit 2 SDA-B Vessel Shell/Roof Complete	3.00	81.05
		Unit 2 SDA-B Inlet Duct Erection Complete		
		Unit 2 SDA-C Support Steel Complete		
34	Nov-19	Unit 2 SDA-A Outlet Duct Erection Complete	2.81	83.86
		Unit 2 Fabric Filter-A Hoppers/Wall/Roof Complete		
35	Dec-19	Unit 2 SDA-C Vessel Shell/Roof Complete	2.76	86.62
		Unit 2 SDA-C Inlet Duct Erection Complete		
36	Jan-20	Unit 2 SDA-B Outlet Duct Erection Complete	2.41	89.03
		Unit 2 Fabric Filter-B Hoppers/Wall/Roof Complete		
		Unit 1 Structural Completion		
37	Feb-20	Unit 2 SDA-C Outlet Duct Erection Complete	2.26	91.29
		Unit 2 Booster Fans Erection Complete		
38	Mar-20	Unit 1 Duct Tie-In Complete	2.23	93.52
39	Apr-20	Unit 1 Mechanical Completion	0.45	93.97
40	May-20	Unit 1 Performance Test Report	0.30	94.27
41	Jun-20	Unit 1 Substantial Completion	0.22	94.49
		Unit 2 Structural Completion		
42	Jul-20	Removal of Fabrication Tables Complete	0.22	94.71
43	Aug-20	Unit 2 Duct Tie-In Complete	0.15	94.86
44	Sep-20	Unit 2 Mechanical Completion	0.07	94.93
45	Oct-20	Unit 2 Substantial Completion	0.07	95.00
		Demobilization Complete		
46	Nov-20	Unit 1 Final Acceptance	2.50	97.50
47	Dec-20	Unit 2 Final Acceptance	2.50	100.00

ATTACHMENT 5

S&L Estimating Documentation:

Indirects and Construction Equipment included in Crew Rates

Indirects and Construction Equipment included in Crew Rates

Typical Construction Equipment included in our Crew Rates

- Air compressor
- Air tugger
- Crane, 5 ton
- Crane, 15 ton mobile
- Crane, 35 ton
- Crane, 50 ton
- Crane, 60 ton
- Dozer
- Finishing machine
- Flat bed trailer
- Fork lift
- Front end loader
- Generator
- Grader
- Pickup truck
- Powdered riding buggy
- Roller, sheepsfoot
- Roller, vibratory
- Radial saw
- Scraper
- Stress relieving machine
- Tremie
- Truck mounted concrete pump
- Vibrator
- Water wagon
- Welding machine
- Wire puller

Site Indirects included in Crew Rates

- Job Supervision-Field Staff
- Administration-Field Staff
- Personnel Hiring
- Craft Superintendents
- Safety / Purchasing/Expediting-Field Staff
- Material Control-Field Staff
- Engineering Liaison-Field Staff
- Project Controls-Field Staff
- Cost/Schedule Controls-Field Staff
- Quality Control Inspection-Field Staff
- Project Office Supplies-Field Staff
- Computer Expenses
- Service Trucks/Supplies
- Field and Shop Mechanics and Supplies
- Subcontract Administration
- Warehousing-Field Staff
- Field Surveying
- Water & Ice
- Sanitation and Cleanup
- Move In/Move Out
- Detours/Barricades/Flags
- Security
- Temp. Utilities/Distr/Hookup
- Temporary Site Improvement
- Temporary Facilities/Buildings
- Utilities Consumption
- Employee Expenses
- Legal Expenses/Claims
- Permits and Fees
- Timekeeping

ATTACHMENT 6

S&L Estimating Documentation:

Escalation Projections

Entergy
White Bluff DGFD Project
Escalation Projections

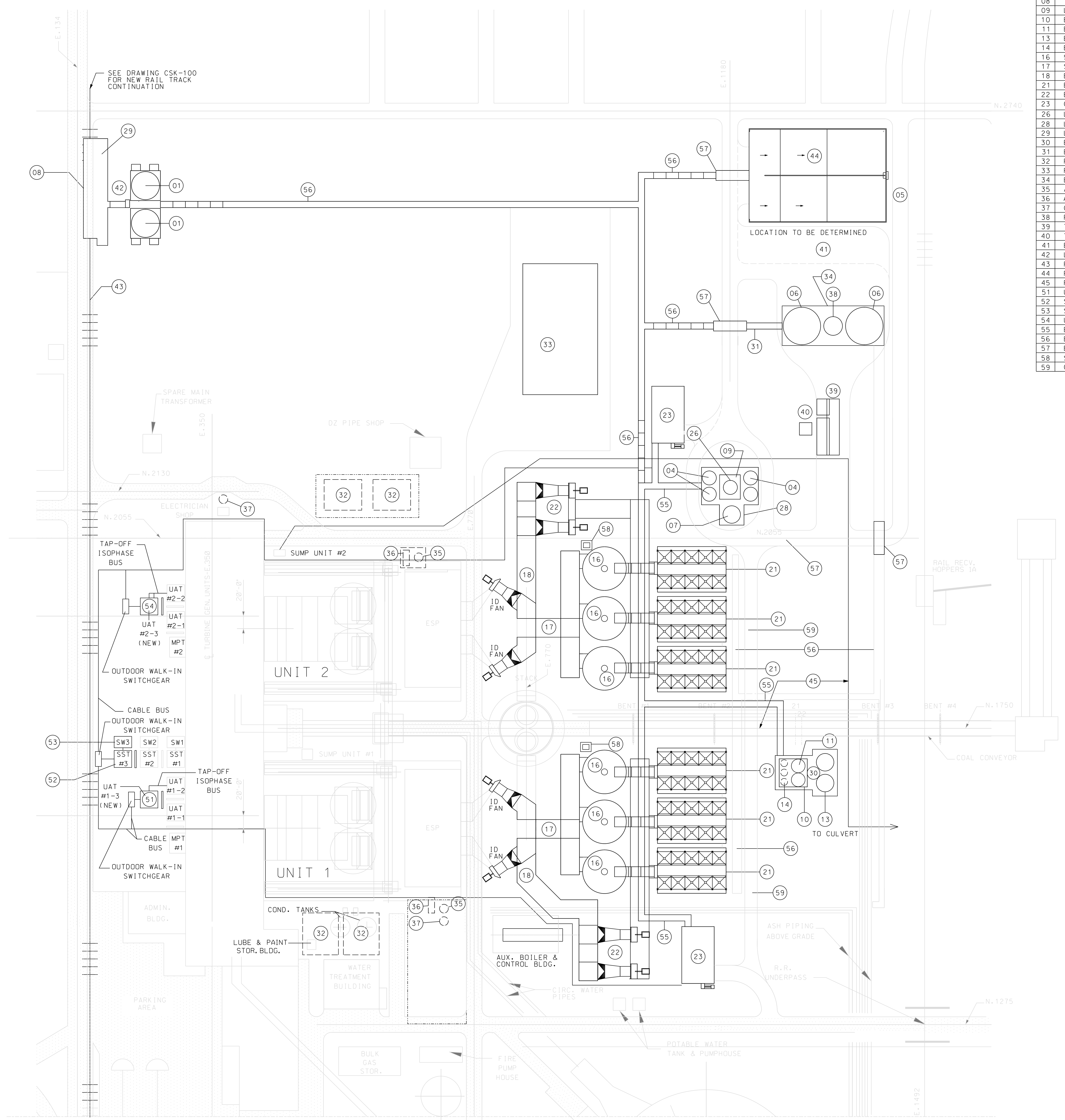
Basis: Pine Bluff Arkansas Labor rates as published in RS Means	Yearly Base Rates + Fringes										
Craft Description	2009	2010	2011	2012	2013	2014	% increase in past 1 year	% increase in past 2 years	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % labor increase next 5 years.
Boilermaker	$38.59	$41.59	$41.59	$41.59	$43.10	$44.39	2.99%	6.73%	6.73%	15.03%	
Iron worker	$28.06	$30.44	$30.44	$30.44	$32.05	$34.00	6.08%	11.70%	11.70%	21.17%	
Pipe Fitter	$25.28	$31.65	$31.65	$31.65	$35.56	$35.56	0.00%	12.35%	12.35%	40.66%	
Electrician	$35.74	$35.74	$35.74	$35.74	$36.95	$36.95	0.00%	3.39%	3.39%	3.39%	
Common Laborer	$16.83	$17.47	$17.47	$17.47	$17.47	$17.47	0.00%	0.00%	0.00%	3.80%	
Average increase in five major crafts							1.82%	6.83%	6.83%	16.81%	**18%**

Misc Material and Equipment (Please see Note 1)	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % increase next 5 years.
Construction & Building Index	8%	15%	17.00%
Material Price, Construction Mat.	8%	7%	10.00%
Plant Cost Index	no increase	slightly negative	5.00%
Civil Work	8%	14%	15.00%
Steel - ductwork	no increase	slightly negative	8.00%
Steel - rolled shape	8%	no increase	10.00%
Architectural	5%	4%	8.00%
Overall mechanical equipment	4%	1%	7.00%
Overall piping	6%	11%	12.00%
Overall electrical equipment	9%	17%	18.00%
Raceway, Cable Tray, & Conduit	8%	slightly negative	10.00%
Electrical cable	14%	7%	15.00%
Controls & Instrumentation	1%	1%	5.00%
Average overall increase for Power back-fit projects	**7%**	**9%**	**11%**

Note 1: From major industrial sources such as BLS, Chemical Engineering, Handy Whitman, ENR Commodity pricing (20 city average),

ATTACHMENT 7

Conceptual General Arrangement Drawing



LEGEND	
01	LIME STORAGE SILOS
03	NOT USED
04	LIME SLURRY FEED TANKS
05	BYPRODUCT HAUL ROAD
06	BYPRODUCT STORAGE SILOS
07	SLAKING WATER STORAGE TANK
08	TRAIN UNLOADING SHED
09	LIME PREPARATION BUILDING
10	BYPRODUCT RECYCLE EQUIPMENT BUILDING
11	BYPRODUCT RECYCLE DAY BINS
13	BYPRODUCT RECYCLE MAKE-UP WATER TANKS
14	BYPRODUCT RECYCLE SLURRY TANKS
16	SPRAY DRYER ABSORBERS
17	SDA FLUE GAS INLET DUCTS
18	BOOSTER FAN DISCHARGE
21	BAG HOUSES
22	BOOSTER FANS
23	COMPRESSOR / ELECTRICAL BUILDINGS
26	LIME DAY BIN
28	LIME PREPARATION AREA
29	LIME UNLOADING EQUIPMENT ROOM
30	BYPRODUCT RECYCLE AREA
31	ELEVATED BOP CONTRACTOR UTILITY RACK
32	FUTURE PROVISION SPACE FOR SCRS
33	FGD SPARE PARTS WAREHOUSE
34	BYPRODUCT HANDLING AREA
35	ACI SILOS
36	ACI ELECTRICAL BUILDINGS
37	CHI TANK
38	FLY ASH SILO
39	TRUCK SCALES
40	TRUCK SCALE HOUSE
41	BYPRODUCT TRUCK PARKING
42	LIME UNLOADING AND STORAGE AREA
43	RAIL SPUR
44	PROCESS WATER RETENTION PONDS
45	PROPOSED GRATED CONCRETE TRENCH
51	UNIT AUX. TRANSFORMER UNIT 1
52	STARTUP / STANDBY TRANSFORMER COMMON (UNITS 1&2)
53	SWITCH
54	UNIT AUX. TRANSFORMER UNIT 2
55	ELEVATED FGD CONTRACTOR UTILITY RACK
56	BOP SLEEPER RACK
57	BOP TRENCH
58	SDA PENTHOUSE ELEVATOR
59	CRANE MAINTENANCE AISLE

HOLD INFORMATION

NO.	DATE	DESCRIPTION

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION

REV.	DATE	DESCRIPTION

ISSUE PURPOSE: ISSUED FOR STUDY

SPECIFICATION: -

PROJECT NO.: 13138-001

I HEREBY CERTIFY THAT THIS ENGINEERING DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT PERSONAL SUPERVISION AND THAT I AM A DULY LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ARKANSAS.

ENTER NAME
ENTER DATE

MY LICENSE RENEWAL DATE IS: ENTER DATE
PAGES OR SHEETS COVERED BY THIS SEAL:
THIS DOCUMENT ONLY.

CAD FILE NAME: M-GA-001.DGN

PREPARED BY: D.J.MERRICK

REVIEWED BY: G.A.RIVERA

APPROVED BY: S.C.MCHONE

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

Sargent & Lundy LLC

SARGENT & LUNDY LLC
55 EAST MONROE STREET
CHICAGO, ILLINOIS 60603-5780
WWW.SARGENTLUNDY.COM
CERTIFICATE OF AUTHORIZATION NO. 6938

Entergy

PROJECT

WHITE BLUFF STATION
UNITS 1 & 2
ENTERGY

DRAWING TITLE

GENERAL ARRANGEMENT
SDA SITE DEVELOPMENT

PRELIMINARY
NOT FOR
CONSTRUCTION

GRAPHIC SCALE 60' 0 60' 120' 180'

DRAWING SCALE 1" = 60'-0"

DRAWING NUMBER	REVISION
M-GA-001	N/A

SHEET 1 OF 1

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ATTACHMENT 8

Entergy Basis of Contingency

WB FGD Project

Risk Register

Contingency Estimate					
Estimate Total w/o Contingency, IDC, Escalation	**$ 740,968,200**				
	P90	**P80**	**P70**	**P60**	**P50**
Risk Contingency	**$ 35,870,000**	**$ 27,220,000**	**$ 20,550,000**	**$ 16,210,000**	**$ 13,090,000**
Estimate Uncertainty Contingency	**$ 95,350,000**	**$ 66,600,000**	**$ 41,540,000**	**$ 21,330,000**	**$ (290,000)**
Unknown Risk Contingency	**$ 18,560,000**	**$ 17,380,000**	**$ 16,450,000**	**$ 15,610,000**	**$ 14,810,000**
Total Contingency	$ 149,780,000	$ 111,200,000	$ 78,540,000	$ 53,150,000	$ 27,610,000
Percentage of Total	20%	15%	11%	7%	4%
Total Estimate w/ Contingency	$ 890,748,200	$ 852,168,200	$ 819,508,200	$ 794,118,200	$ 768,578,200

Project Delivery Standard

	Estimate Characteristic			Resulting Range	
Estimate class	**Maturity level of project definition** **expressed as % of complete engineering**	**End usage** **typical purpose of estimate**	**Methodology** **typical estimating method**	**Estimate accuracy range** **typical variation in low & high ranges**	**Target contingency range**
Class 5	0 to 2%	Rough Order of Magnitude (ROM)	Capacity factored, parametric models, judgment, or analogy	-50 to +100%	30 to 50%
Class 4	1 to 15%	Feasibility	Equipment factored or parametric models	-30 to +50%	25 to 40%
Class 3	10 to 50%	Funding Authorization	Semi-detailed unit costs with assembly level line items	-20 to +30%	15 to 30%
Class 2	30 to 90%	Control	Detailed unit costs with forced detailed take-off	-15 to +20%	5 to 20%
Class 1	50 to 100%	Check Estimate	Detailed unit cost with detailed take-off	-10 to +15%	2 to 7%

ESTIMATE UNCERTAINTY

Risk Category	Description of Risk	Quantitative Risk Analysis					Status / Comments
		Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	
Estimate Uncertainty	**EPC Contract**	$ 752,912,300	($188,228,075)	$0	$188,228,075	From S&L estimate report, the project definition and accuracy of the individual components in this estimate result in an overall accuracy of +/- 25%.	
Estimate Uncertainty	**Owner's Costs**	$ 58,546,000	($11,709,200)	$0	$17,563,800	Estimate from Entergy, estimate is considered a Class 3 (+30% to -20%).	Entergy Indirects were calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.
Estimate Uncertainty	**Third Party Services**	$ 12,544,000	($3,136,000)	$0	$3,136,000	From S&L estimate report, estimate is considered a Class 3 (+25% to -25%)	

UNKNOWN RISK							
		Quantitative Risk Analysis					
Risk Category	Description of Risk	Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	Status / Comments
Unknown Risks	**UNKNOWN RISKS:** This is part of the calculation for the overall contingency to include in the project budget.	$ 740,968,200	$ 7,409,682	$ 14,819,364	$ 22,229,046	Estimating standard guidance. Min = 1%, Exp = 2%, Max = 3%	Due to lack of historical data and current project development, there are a range of potential impacts from unknown risks not yet captured in the estimate uncertainty and identified risks, Entergy contingency guidance is to use 1% - 3% of the total estimate without contingency. This item can be captured in the risk register and modeled with the identified risks when estimating contingency.

IDENTIFIED RISKS

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-007	Budget	**PROJECT BUDGET - CRAFT LABOR - PER DIEM RATE RISK:** This risk is related to the required craft labor per diem increasing due to the high demand of craft labor, at a percentage greater than the estimated rate.	ALL	3	2	0	0	**6**	Low	An increase to per diem to attract labor will increase the project total estimate.	45%	$0	$0	$4,290,000	Yes	The estimated Per Diem is $13M. Assume a 33% increase as a max.	
2014-002	Budget	**PROJECT BUDGET - CRAFT LABOR - WAGE RATE ESCALATION:** This risk is related to wage rates rising, at a rate greater than the rate used in the estimate, due to the high demand for craft labor.	ALL	3	3	0	0	**9**	Low	Received rates over 10-year period from S&L. Range has fluctuated from 0% to 21.23% during that period. Current economic conditions indicate a high probability of craft labor rates increasing beyond the current projection of 3.35% provided by S&L.	45%	($19,700,000)	$0	$42,300,000	Yes	Received rates over 10-year period from S&L. Looked at range and average high and low rates. Expected escalation rate is 3.35%. Assumed Min rate of 1.675% and Max rate of 6.7%. Results in potential increase of $42.3M over current escalation estimate and potential decrease of $19.7M.	
2014-001	Budget	**PROJECT BUDGET - IDC:** This risk is related to the cost of capital increasing over the life of the project, at a rate different than the current estimated escalation rate.	ALL	1	5	0	2	**7**	Low	The EPA Cost Control Manual uses a rate of 7% which was used for the estimate. Historical EAI AFUDC rates have been under 7%.	5%	$0	$0	$25,000,000	Yes	Assumes an index rate of 7.5%; this results in an increase of ~$25M over current IDC estimate.	
2014-006	Budget	**PROJECT BUDGET - CAPITAL SUSPENSE ADJUSTMENTS:** The risk is related to Capital Suspense increasing over the life of the project from the current Entergy forecasted rate.	ALL	2	3	1	1	**10**	Low	Adjustment of rates impact the project total estimate.	25%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	

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Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
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2014-005	Budget	**PROJECT BUDGET - EPC MATERIAL ESCALATION:** Project material cost may be subject to escalation	ALL	1	3	0	1	**4**	Low	Material escalation is included in the project estimate.	5%	$0	$0	$0	No	Material escalation is included in the project estimate. The estimate uncertainty addresses the risk of the amount of material and the material escalation rate being different than the current forecasted rates.	
2014-003	Budget	**PROJECT BUDGET - LIME ESCALATION:** Project lime cost may be subject to escalation different than the estimated rate.	ALL	3	1	0	0	**3**	Low	Assume that lime escalation rate will increase during project.	45%	$0	$0	$0	No	Budgeted Lime escalation rate is 2.15%. The estimate uncertainty addresses the risk of the amount of material and the escalation rate being different than the current forecasted escalation rate.	
2014-005	Budget	**PROJECT BUDGET - MATERIAL LOADER ADJUSTMENTS:** The risk is related to the material loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	1	0	0	**4**	Low	Probability that Material Loaders will change over life of the project.	20%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	
2014-004	Budget	**PROJECT BUDGET - PAYROLL LOADER ADJUSTMENTS:** The risk is related to the payroll loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	2	0	0	**8**	Low	Probability that Payroll Loaders will change over the life of the project.	70%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the Entergy Payroll estimate.	
2014-006	Budget	**SALES TAX:** Risk that the sales tax rate will change and add additional costs to the project.	ALL	2	1	0	0	**2**	Low	Probability that the Sales Tax will change order the life of the project.	20%	$0	$0	$0	No	The risk associated with a Sales Tax change will be included in the estimate uncertainty, which also includes the risk of the quantity of materials subject to sales tax.	

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2014-010	Eng	**DESIGN CRITERIA:** Design criteria is missing information, or information is incorrect resulting in changes to the technical specifications and requirements during the project. The risk would result in re-engineering / re-work.	ALL	2	3	3	1	**14**	Medium Low	The Owner's Engineer (S&L) has performed Engineering Studies in 2009 and 2013. The revised Design Criteria document reflects the current project requirements.	20%	$0	$5,000,000	$25,000,000	Yes	Assumption that the design criteria accurately reflects the requirements of the project, any corrections will have minimal impact to detailed design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-011	Eng	**ENGINEERING SUPPORT:** Inadequate support to review EPC contractor's design to ensure it meets Entergy requirements. The risk would result in re-engineering / re-work.	ALL	1	3	3	2	**8**	Low	The Project will use an Owner's Engineer to augment staff requirements to mitigate this risk. This risk is the potential for redesign based on inadequate reviews.	5%	$0	$5,000,000	$25,000,000	Yes	Assumption that there will be minimal rework based on inadequate Entergy review of EPC contractor design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-012	Eng	**SCOPE GAP OR CHANGES:** Work scope not defined in EPC contract, and not identified/unforeseen conditions in project budget. Risk would result in additional scope to EPC contract.	ALL	2	4	3	2	**18**	Medium Low	Low probability due to 2009 and 2013 studies. BOP scope not as defined as FGD island. There is only minimal engineering complete at this stage. Also, risk covers the potential for additional design requirements over base FGD design to meet Entergy standard designs.	20%	$5,000,000	$15,000,000	$45,000,000	Yes	Assumption that any missed scope will not be significant, there is an Open Book period for development. Assume minimum of 1% of the $500M FGD direct costs, 3% expected, 9% max.	
2014-013	Eng	**TECHNOLOGY - BAGHOUSE**: The baghouse on each of the units fails to meet the PM emissions limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	
2014-014	Eng	**TECHNOLOGY - Dry FGD**: The selection of the technology to meet the emission limits with margin is insufficient to meet the required limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	

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2014-015	Env	**AIR PERMIT (AR) - DELAY**: Delay in receiving the permit, for an additional 6 months (24 total).	ALL	1	2	3	3	**8**	Low	Cost impact to expedite project to stay on schedule as a result in the delay. The current timeline of 18 months accounts for some expected delay.	5%	$0	$0	$3,000,000	Yes	Assume $500k/month for up to 6 mo of delay. This would be prior to FNTP.	In the current timeline, there is some schedule float that could be used. Entergy could release FNTP prior to receipt of the air permit.
2014-016	Env	**ASH DISPOSAL:** EPA determines that combustion byproducts are a hazardous waste resulting in need to utilize other material to stabilize scrubber byproduct.	ALL	1	1	0	3	**4**	Low	Cost impact: possible HAZMAT training and treatment of ash. Still would landfill on site. Loss of ash sales.	5%	$0	$0	$150,000	Yes	Assume some additional training, and minimal equipment modifications.	Most ash will be collected in the ESP. This risk would be addressed by a separate project.
2014-018	Env	**COMPLIANCE RULE - Vacated or Delayed:** If the rule is vacated or delayed, what is the impact?	ALL	1	2	0	0	**2**	Low	Assume delay prior to project approval but same compliance period to comply. Cost impact: engineering, payroll, AFUDC during delay period.	5%	$0	$0	$3,000,000	Yes	Project delayed prior to LNTP. Assume $500k/month for 6 months.	
2014-017	Env	**ASH DISPOSAL:** The ADEQ might impose the same permit restriction as it did at the Flint Creek Plant and not allow WB to route landfill leachate directly to the surge pond.	ALL	3	0	0	1	**3**	Low	Project will not increase probablility to occurrence; plant O&M risk. Cost impact: treatment of leachate prior to sending to surge pond.	45%	$0	$0	$0	No	Plant O&M risk.	
2014-019	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB1	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$4,000,000	$16,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-8 mo delay at $2M/month. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.

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2014-021	EPC	**Delay in FNTP:** Delay in Entergy issuing FNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in issuing FNTP. Delays for receipt of the air permit or regulatory approval are separately identified risks.	20%	$0	$3,000,000	$6,000,000	Yes	Assume EPC contractor request compensation for the FNTP delay (equipment contracts, etc). ($1M/month delay)	
2014-022	EPC	**Delay in LNTP:** Delay in Entergy issuing LNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in receiving internal approvals.	20%	$0	$1,500,000	$3,000,000	Yes	Assume EPC contractor request compensation for the LNTP delay (equipment contracts, etc). ($0.5M/month delay)	
2014-023	EPC	**EPC CONTRACT EQUIPMENT VALUE:** Equipment estimate uncertainty during the period from when the contract price is developed to the LNTP.	ALL	2	4	0	1	**10**	Low	The time between the Open Book Period and LNTP is approximately 14 months.	20%	$0	$8,000,000	$20,000,000	Yes	Risk of price changes for $400M of the EPC contract, subject to 14 months between negotiation and award. Min = 0%, Exp = 2%, Max = 5%	
2014-024	EPC	**EPC CONTRACT:** Negotiated EPC fee	ALL	2	4	0	2	**12**	Medium Low	EPC Fee assumed to be in the 8%-15% range.	20%	($12,000,000)	$0	$12,000,000	Yes	Estimate includes a 10% fee or ~$60M. Min = 8% fee, Max = 12% fee.	
2014-069	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (EPC procurement costs)	ALL	1	1	1	3	**5**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$7,500,000	Yes	Estimate of EPC procurement costs, negotiating, and potential incrase on contract value. To account for procurement activities, Max 1% of EPC value	

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2014-070	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (schedule delay)	ALL	1	5	5	5	**15**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$36,000,000	Yes	Default of the EPC contractor would result in delay of project to procure and onboard a new contractor. For this calculation, the EPC contractor is assumed to default during construction. Apply amount of IDC ($4M/mo) plus carrying costs of Entergy costs ($500k/mo) at this date through end of project to the expected delays (max: 8 mo).	
2014-032	EPC	**SCHEDULE - Delayed:** Change in project schedule due to longer compliance timeline.	ALL	1	1	1	1	**3**	Low	Assume that, if compliance date is delayed, then all costs will shift accordingly. Incremental costs would be maintaining internal staff in the interim, IDC.	5%	$0	$0	$12,000,000	Yes	Assume delay would be known before contract award, when the FIP or SIP is issued. Delay of min = 0 mo, exp = 0 mo, max = 24 mo @ $500k/mo	
2014-033	EPC	**SCHEDULE - Shorter Compliance Timeline:** Change in project schedule that shortens compliance timeline.	ALL	1	4	0	3	**7**	Low	Assume that labor costs and costs to expidite equipment would increase to comply with earlier timeline.	5%	$0	$0	$30,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less IDC costs. Assume 15% increase of estimated craft labor of ~$200M.	
2014-035	EPC	**UN-IDENTIFIED UNDERGROUND OBSTRUCTION:** Claims for extra work for un-identified underground pipe, etc.	ALL	2	3	2	2	**14**	Medium Low	Project plans to perform exploration work to identify unknown underground obstructions during the Open Book period. This risk if realized will increase the EPC contract price.	20%	$0	$500,000	$3,000,000	Yes	Assumption that any missed scope will not be significant. Schedule delays of $500k/month.	

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2014-036	EPC	**WEATHER-RELATED DELAYS:** Extreme weather can greatly affect craft productivity and result in partial or complete site shutdown. Such weather conditions can increase the risk and provide the basis for a contractor claim for a change order.	ALL	1	1	3	2	**6**	Low	The project is subject to extreme weather events. This risk will be further developed during the Open Book period.	5%	$0	$4,000,000	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month. Assumption that the current schedule has sufficient float to mitigate this risk. The Open Book period will be used to develop a more detailed schedule.	The project execution plan is to perform a majority of the construction prior to any outage. Weather risks will be assigned to the EPC contractor.
2014-020	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB2	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$0	$0	No	Risk QRA combined with EPC Construction Delays for WB1. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.
2014-008	EPC	**LABOR:** Schedule delays due to union labor disputes.	ALL	1	2	2	2	**6**	Low	Using non-union labor.	5%	$0	$0	$0	No	Using non-union labor.	

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2014-027	EPC	**OPEN BOOK PERIOD**: Change in contract terms (Limitiation of Liability) during EPC contract negotiations.	ALL	1	3	0	1	**4**	Low	The RFP process to select the EPC contractor will require the contractor to state required terms for an EPC contractor prior to their selection. The Open Book period should not increase their project risk profile, which would be a driver for a change in their terms.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-028	EPC	**OPEN BOOK PERIOD**: Change in rates from EPC contractor during open book period.	ALL	1	1	0	1	**2**	Low	The EPC contractor's labor and equipment rates will be negotiated during the Open Book period to develop the contract price.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-029	EPC	**OPEN BOOK PERIOD**: Unable to negotiate a fixed price contract.	ALL	1	0	0	0	**0**	Low	The scope and schedule of this project are sufficient to meet the project goals. There is no indication that this risk is probable.	5%	$0	$0	$0	No	Not included in QRA.	
2014-030	EPC	**POOR PERFORMANCE BY CONTRACTOR ON PROJECT:** Risk of claims and change orders increases if contractor expects and/or experiences loss on the project.	ALL	1	1	2	1	**4**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy. Risk is for total claims greater than the amount of contingency.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-031	EPC	**POOR QUALITY OF CONTRACTOR WORK**: Schedule impact due to rework and adverse affect on long-term plant operation.	ALL	1	1	2	1	**4**	Low	EPC bidders will be selected based on Entergy experience and previous work experience.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

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2014-034	EPC	**SCOPE OR DESIGN PROBLEMS:** Poor scope, technical design, or unclear technical requirements could result in change orders with added cost and/or schedule delay or an end product that does meet customer needs	ALL	3	3	3	2	**24**	Medium Low	Complicated project with many interfaces to exisitng facility. Assume multiple small change orders.	45%	$0	$0	$0	No	Not included in QRA. This risk is similar to Engineering risks. Project estimate includes estimate uncertainty for this risk.	
2014-037	EPC	**POOR PERFORMANCE:** Contractor does not meet schedule or performance requirements.	ALL	2	1	2	1	**8**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy.	20%	$0	$0	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month.	
2014-038	Goal	**COMPLIANCE - NON-COMPLIANCE**: The new emission standards cannot be met by the units.	ALL	1	5	5	5	**15**	Medium Low	Industry information shows that the emission compliance levels can be met with the available tecnologies.	5%	$0	$0	$0	No	Cost estimate is beyond project value.	
2014-053	Ops	**LONG TERM OPERATION - CAPACITY:** Unit derate or capacity restriction resulting from control technologies.	ALL	1	1	1	1	**3**	Low	Unit capacity will be affected by this project. It will be defined and a guarantee will be negotiated with the EPC contractor.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine capacity impact of project.
2014-054	Ops	**LONG TERM OPERATION - INCREASED O&M:** Increases to the unit's O&M due to control technology.	ALL	1	1	1	1	**3**	Low	Additional O&M will be required by this project. It will be defined when the technology is selected during the Open Book period.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-055	Ops	**LONG TERM OPERATION - OPERATOR INTERFACE:** An increase in training requirements due to control technology.	ALL	1	1	1	1	**3**	Low	Additional Operator interface will be required by this project.	5%	$0	$0	$0	No	Not a project risk.	Additional Operations staff is included in the project estimate. Review this risk after Open Book Period to determine impact of project.

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2014-056	Ops	**LONG TERM OPERATION - RELIABILITY:** Impacts to the unit's reliability.	ALL	1	1	1	1	**3**	Low	The EPC contract will require equipment guarantees and system redundancy to provide reliability.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-057	Permiting	**Department of Transportation:** Impact of schedule delay due to permitting the road modification.	ALL	1	1	1	0	**2**	Low	Unable to determine risk until Open Book Period to understand permit time required and date when road modification must be in place.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine O&M impact of project.
2014-058	Permitting	**REGULATION CHANGE:** Change in future regulation to lower emission limits or 30-day rolling average.	ALL	1	1	0	0	**1**	Low	Need additional information, this would be a future project. Technology for FGD has not been determined	5%	$0	$0	$0	No	Risk will be mitigated during technology selection.	
2014-040	PM	**INTERNAL APPROVALS:** Possible delays due to delay of internal approval of contracts	ALL	2	1	1	2	**8**	Low	Risk exists with the challenges of obtaining internal approvals.	20%	$0	$0	$1,500,000	Yes	Assume internal project team continues to support Board approval during the regulatory and permitting periods. (Assume $500k/mo).	
2014-041	PM	**ISSUE RESOLUTION:** Possible schedule delays due to non-resolution of issues as they arise.	ALL	2	2	3	2	**14**	Medium Low	Risk exists for undefined issues.	20%	$4,500,000	$9,000,000	$13,500,000	Yes	Undefined issues may impact schedule & project scope. (Assume AFUDC ($4M) + Owner's costs ($500k) per month) Min = 1 mo, expected = 2 mo, max = 3 mo)	
2014-039	PM	**COMMUNICATIONS:** Possible schedule delays and costs increases due to poor communication between all parties	ALL	1	1	2	2	**5**	Low	Risk exists for contractor claims. The contracting strategy using only one EPC contractor should minimize this risk.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $. Adequate staffing of project is a separate risk.	

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2014-042	PM	**MANAGEMENT - INSUFFICIENT INTERNAL PROJECT STAFF:** Insufficient Internal project resources - unable to meet schedule. Project costs increase.	ALL	2	2	0	2	**8**	Low	Internal labor costs would be higher than budgeted.	20%	$0	$0	$0	No	Project will plan to use outside contractors to staff project.	
2014-043	PM	**MANAGEMENT - PRUDENCY DETERMINATION:** The project team is unable to justify and document project decisions and the related costs to defend decisions as prudent in future rate cases. Mitigation includes processes for contemporaneous documentation.	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-044	PM	**PROJECT CONTROLS:** Project has insufficient project controls / oversight / documentation to manage and control cost.	ALL	1	3	0	4	**7**	Low	Stage Gate process requires project controls. Generic project costs would be higher than budgeted.	5%	$0	$0	$0	No	Additional staff included in the project estimate to cover PEI oversight of project.	
2014-045	PM	**RECORDS MANAGEMENT:** Document control is insufficient leading to inability to support Regulatory Recovery	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-048	PM	**SCOPE CHANGES:** Possible delays or increased cost due to improperly managed project scope changes.	ALL	1	2	2	2	**6**	Low	Potential delays due to internal decisions in a timely manner.	5%	$0	$0	$0	No	Not included in QRA. Missed scope part of the Engineering risks.	

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Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-059	Reg	**REGULATORY - DELAY:** Regulatory delays could negatively affect the project schedule. The expected duration is estimated to be 18 months.	ALL	2	2	5	4	**22**	Medium Low	Project schedule assumes 18 mo to receive approval. If additional time is required, Entergy may choose to issue FNTP prior to receipt to avoid potential costs.	20%	$0	$0	$3,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less AFUDC costs. ($0.5M/month delay)	
2014-068	Schedule	**SCHEDULE - FORCE MAJEURE** - Increase in cost of project due to force majeure	ALL	1	1	1	1	**3**	Low	BAR insurance will be in place.	5%	$0	$0	$10,000,000	Yes	Insurance deductible is expected to be structured similar to other projects. $500,000 deductible for flood, 5% of insured value for Named Windstorm with min of $1,000,000 and max of $10,000,000.	
2014-062	Schedule	**COMPLIANCE - DEADLINE**: Risk that the project will not meet the deadline?	ALL	1	3	4	3	**10**	Low	Current timeline has sufficient time to develop project.	5%	$0	$0	$0	No	Current schedule reflects adequate available time to complete the project. EPC contract will include schedule requirements.	
2014-063	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB1	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-064	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB2	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-066	Schedule	**SCHEDULE INSUFFICIENT:** EPC Contractor does not provide schedule with sufficient level of detail to coordinate activities	ALL	1	1	1	1	**3**	Low	EPC contract will require detailed project schedule. Entergy project controls will be in-place to support schedule development and maintenance.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-067	Supply Chain	**LIME AVAILABILITY:** Will the required lime for the long term operation be available?	ALL	1	1	1	1	**3**	Low	S&L study did not identify lime availability concerns.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

Probability and Impact Definition

Probability Rating	Probability Definition (Likelihood of Occurrence)	Discreet Value for QRA
1	Less than or equal to 10 % Probability of Occurrence	5%
2	Greater than 10% but less that 30 % Probability of Occurrence	20%
3	Greater than 30% but less that 60 % Probability of Occurrence	45%
4	Greater than 60% but less that 80 % Probability of Occurrence	70%
5	Greater than 80% Probability of Occurrence	90%

Cost Impact Rating	Cost Impact Value (Impact to Entergy Cost only) (Project Cost = $500M)	Min Cost Impact (QRA)	Most Likely Cost Impact (QRA)	Max Cost Impact (QRA)
1	(<0.5% of project cost)	$ 100,000	$ 1,000,000	$ 2,500,000
2	(0.5% - 1.4% of project cost)	$ 2,500,000	$ 4,750,000	$ 7,000,000
3	(1.5% - 2.9% of project cost)	$ 7,000,000	$ 11,000,000	$ 15,000,000
4	(3% - 4.9% of project cost)	$ 15,000,000	$ 20,000,000	$ 25,000,000
5	(>5% of project cost)	$ 25,000,000	$ 37,500,000	$ 50,000,000

Schedule Impact Rating	Schedule Impact Value (Impact to Affected Summary Activity)	Min Schedule Impact (QRA)	Most Likely Schedule Impact (QRA)	Max Schedule Impact (QRA)
1	Less than 30 days	0	15	30
2	Between 30 and 60 Calendar days	30	45	60
3	Between 60 and 90 Calendar days	60	75	90
4	Between 90 and 150 calendar days	90	120	150
5	Between 150 and 210 calendar days	150	180	210

Other Impact Rating	Other Effect on Project (Regulatory/Legal, Safety, Company Reputation and Quality) - more details below
1	No impact
2	Minimal Impact
3	Moderate Impact
4	Significant Impact
5	Severe Impact

Other Impact Value	IMPACT (Effect on Project)
1	Has no impact on (**Company Reputation**)
	Has no impact on quality (**Quality**)
	Not likely to result in injury or illness (**Safety**)
	No impact on timely CPCN or full cost recovery (**Regulatory/Legal**)
2	Has limited impact on (**Company Reputation**)
	Quality issue has minimal impact on project (**Quality**)
	Has a direct, minor impact on a near miss driver, an OSHA RA driver, or human error mechanism. Is an emerging
	CPCN delayed by less than 1 month and/or cost disallowance up to $7,500,000 (**Regulatory/Legal**)
3	Has moderate impact on (**Company Reputation**)
	Quality issue affects work activities and requires application of the corrective action program (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. An emerging safety issue where a
	CPCN delayed between 1-3 months and/or cost disallowance between $7,500,000 and $12,500,000
4	Has significant impact on (**Company Reputation**)
	Quality issue requires immediate management attention (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. No workaround is present.
	CPCN delayed between 3-5 months and/or cost disallowance between $12,500,000 and $20,000,000
5	Has severe impact on (**Company Reputation**)
	Quality issue requires work stoppage (**Quality**)
	Likely to cause one or more deaths (**Safety**)
	CPCN delayed more than 5 months and/or cost disallowance greater than $20,000,000 (**Regulatory/Legal**)

* The Project manager should establish clear thresholds for financial impact at the outset of the project. These should be articulated in the Project Execution Plan and be approved in accordance with the provisions of the Project Management Manual.

ENTERGY ARKANSAS, INC.

WHITE BLUFF

DSI COST ESTIMATE BASIS DOCUMENT

SL-014000
Final, Rev. 0
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Project 13027-002

Prepared by

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CONTENTS

1. PURPOSE

Entergy has requested that Sargent & Lundy (S&L) evaluate installation of a new dry sorbent injection (DSI) system on the units at White Bluff to control sulfur dioxide (SO_2) emissions. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) and the capital cost estimates.

2. TECHNOLOGY DESCRIPTION

DSI is a proven technology, which has only recently been implemented, for moderate removal of SO_2 and other acid gases from coal-fired power plants. It involves injection of sodium-based sorbents into the ductwork after the boiler and prior to the particulate collection device. DSI is a relatively low capital cost, moderate SO_2 removal alternative to wet or dry FGD systems. No slurry equipment or separate reactor vessel is required with a DSI system. With the proper temperature profile and stoichiometry, the sorbent can effectively react with $SO_2$and other acid gases in the flue gas. The resulting particulate matter is removed from the flue gas by a particulate collection device, typically an existing electrostatic precipitator (ESP).

The typical DSI sorbents include sodium bicarbonate ($NaHCO_3$) and Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$). Sorbent injection into the ductwork (downstream of the boiler and upstream of the ESP) has been tested in the industry using sodium-based sorbents. The process works through neutralization of SO_2 and other acid gases with the caustic sorbent; the neutralization occurs as long as the sorbent remains in contact with the gas. Sorbent injection has been proven effective on a variety of pulverized coal-fired boilers using a range of low to high sulfur coals. It is considered a commercial technology although with a limited supplier base due to the historically limited interest.

The DSI process produces a dry byproduct which can be landfilled. The waste products will contain sodium sulfate and sulfite ($NaSO_3$/$NaSO_4$) along with the unused sorbent and the normal fly ash. These wastes will be collected in the ESP and can be transported with conventional pneumatic fly ash handling equipment. The waste from sodium-based sorbents will have relatively high concentrations of soluble salts, which may affect the byproduct handling. With the addition of dry sorbent byproducts fly ash cannot be sold for reuse.

3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the DSI technology supplier providing the main process equipment, including reagent storage, milling, conveyance, and injection lances.
- Reagent injection at the air preheater (APH) outlet, upstream of the existing ESP. The cost to rebuild/upgrade the ESP was included to ensure there is no increase in PM emissions as a significant quantity of reagent will be added upstream of the existing ESP.
- On-site disposal of DSI byproduct using upgraded ESP ash handling equipment. The byproduct will be collected in the existing ESP in conjunction with the fly ash from the units; no additional blending equipment is required.
- Reagent injection rates based on 50% SO_2 removal from a design inlet concentration of 0.76 lb SO_2/MMBtu, based on the highest 5% of SO_2 emissions from 2009 through 2013.
    - Annual operating costs will be based on 50% SO_2 removal from an uncontrolled SO_2 rate of 0.57 lb SO_2/MMBtu, based on the annual heat input weighted average emission from 2009 through 2013.
    - The system will be designed to control emissions to meet a permit limit of 0.35 lb/MMBtu on a 30-boiler day rolling average, based on a maximum 30-day average SO_2 emission rate of 0.66 lb/MMBtu from 2014 through 2016.
- Trona was used as the DSI reagent for the purposes of this estimate.
- Increase in carbon consumption by 1 lb/mmacf to mitigate any impacts on mercury performance associated with ACI/DSI interference and mitigate potential for a brown plume.
- A high level conceptual system design, based on the estimated injection rate, was used as input to the DSI cost estimate. The following were estimated based on previous projects and scaled for the predicted dry sorbent injection rate for White Bluff:
    - Auxiliary power consumption
    - Annual reagent consumption
    - Additional carbon consumption
    - Additional water consumption
    - Additional waste production
    - Reagent storage silos
    - Quantity of mills
    - Quantity of blower trains

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs
- Freight
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills (other than reagent)
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 34018A provided in Attachment 1 represents the total cost to Entergy to install DSI technology on a single unit at White Bluff (Unit 1 or 2) including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Waste disposal (DSI waste + increased carbon + unsold fly ash)
- Loss of revenue from fly ash sales
- Reagent consumption (including increased carbon consumption)
- Auxiliary power consumption
- Low quality water consumption for mill cleaning
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Cost Estimate and Capital Cost Estimate 34018A were developed using the assumptions and scope provided in this document. The project definition and accuracy corresponds to a study level estimate as defined in U.S.EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. The costs provided in this report are in 2016 dollars.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

4.1 DESIGN INPUTS AND ASSUMPTIONS

The following assumptions were made for the design basis for the White Bluff DSI Systems:

- Design SO_2 inlet concentration of 0.76 lb SO_2/MMBtu.
- SO_2 inlet concentration of 0.57 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 removal efficiency of 50% (defined by injection rate, described in Section 4.1.1)
- Annual capacity factor of 71.2% (annual average capacity factor for White Bluff Units 1 and 2 based on historical heat input from 2009 through 2013).
- Reagent injection at the APH outlet, upstream of the existing ESP.
- Reagent delivery by rail.
- Existing activated carbon silo storage time will be reduced, rather than adding additional or larger storage silos to the system.
- Compliance deadline of three years from the effective date of the rule.

Before proceeding with a DSI project, a demonstration test should be completed at White Bluff to confirm the feasibility of DSI technology at White Bluff and quantify the potential BOP impacts associated with the project, such as impacts to the ESP performance, interference with mercury control technologies, and leachability of the byproduct.

4.1.1 ESP/Ash Handling Modifications

The DSI system, as defined in this report would require an estimated Trona injection rate of approximately 22,000 lb/hour to achieve 50% reduction at the design SO_2 inlet concentration. This injection rate would result in an increase in the particulate loading to the ESP of almost 40% from the current ash loading, due to the DSI byproducts and unreacted DSI reagent.

The addition of sodium compounds to the fly ash lowers the overall resistivity of the particulate being captured as well as shifting the particle size distribution. These changes have been shown to improve the removal efficiency of an ESP; in some cases this increase has been shown to offset the increased particulate loading to the ESP.

ESP performance can also be negatively impacted by a significant increase in particulate loading associated with the high reagent injection rates required for SO_2 control. It is uncertain whether modifications to the ESPs and ash handling systems would be required to accommodate the addition of DSI at White Bluff. However, at the very high injection rates expected for this project, an ESP rebuild will likely be required to ensure the PM emissions stay below the PSD threshold. Therefore, the capital cost estimate includes the costs to completely rebuild the existing ESPs and ash handling systems at White Bluff.

The size and condition of the existing ESP can play a critical role in the overall performance of DSI. In order to evaluate the existing White Bluff ESP with respect to future operation with DSI, S&L used the EPA program ESPVI 4.0W Performance Prediction Model (ESPVI 4.0W) to simulate the baseline and future operating scenarios, as described below. In addition, S&L contacted an ESP vendor to provide input relating to installation of DSI upstream of the existing ESPs at White Bluff.

The baseline operation was established using various design inputs for the units (as needed by the ESPVI 4.0W model), recent operating data and stack emissions to estimate the efficiency at which the ESP is currently operating. ESPVI 4.0W showed that at the baseline operating conditions the White Bluff ESP operates at approximately 99.7% removal of the total inlet loading, corresponding to a filterable PM emission limit of 0.0155 lb/MMBtu.

ESPs operate at a constant efficiency assuming the operating conditions (such as temperature, ash resistivity, or flue gas velocity) stay the same. DSI can impact some of the operating conditions, specifically ash resistivity and particle size distribution. The addition of DSI thus could result in a higher efficiency than the same ESP, without DSI, could achieve.

The ESPVI 4.0W model was developed prior to the introduction of DSI technology and has not been updated to account for the impacts of adding sorbents upstream of the ESP. However, the model was used to predict the high level impact and/or limitations of installing DSI technology by modifying some of the inputs to simulate the characteristics of a fly ash/sodium sorbent mixture.

Based on the modified ash resistivity and adjusted particle sizes associated with the addition of DSI, the baseline ESPVI 4.0W model was used to estimate the predicted removal efficiency for the White Bluff ESP with DSI, as defined in this report, and assuming all other operating conditions remained the same. ESPVI 4.0W showed an overall removal efficiency which was very similar to the current ESP removal efficiency and resulted in an increase in particulate emissions with the additional loading from the DSI system.

Based on the results from ESPVI 4.0W, the White Bluff ESP may be operating at a marginally higher reduction efficiency with the installation of DSI; however, the loading to the ESP is also increasing significantly. Therefore, the modeling showed that even though the ESP efficiency may increase, the overall PM emissions will still be higher than the current level. This evaluation supports the conclusion that improvement of the existing ESP in conjunction with the DSI project is necessary to avoid increasing PM emissions.

In addition to the modeling that was performed using ESPVI 4.0W, S&L also engaged a vendor experienced with ESP retrofits to provide costs and expertise associated with injection of DSI on an existing ESP. As part of their budgetary quote, the supplier indicated that "while the ESPs are large they are still an efficiency machine and overcoming the new total inlet loading of over 73,000 lb/hr[1] will be extremely difficult to achieve the requested 0.015 lbs/MMBtu outlet PM emissions, without retrofitting the entire ESPs to BART technology. Essentially, the ESPs will need to be rebuilt to 'as-new' condition with the most state-of-the-art technology options" (see Attachment 2).

Finally, in addition to the performance of the ESP, the increased loading will also have an impact on the ash handling system. Therefore, for the purposes of this cost estimate, based on the significant increase in loading, modifications to the ash handling equipment were included in the cost estimate.

4.1.2 Landfill Modifications

The sodium byproducts (salts) that are produced when Trona reacts with SO_2 and other acid gases, along with the unreacted sorbent are soluble in water. The resulting waste collected in the particulate collection device will need to be disposed of in a landfill that is lined and has a leachate collection system. With the addition of DSI, White Bluff will no longer be able to sell their fly ash for beneficial re-use due to the solubility of the sodium salts which would be

[1] The 73,000 lb/hr loading reflects the design fly ash loading plus the additional loading from the DSI injection (byproduct/unreacted sorbent).

present in the waste. The cost to maintain a landfill and open new cells is included in the typical maintenance budget of a plant. It was assumed, that any future landfill cells would include lining and leachate collection; therefore, no landfill modifications will be required to accommodate the addition of DSI and no costs were included in this estimate.

4.2 TOTAL INSTALLED CAPITAL INVESTMENT

The DSI system supplier will provide all of the equipment related to storing, milling, conveying and injecting the reagent; in this case, the system is designed for Trona. The remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DSI system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by the following areas:

4.2.1 DSI Area (Single Unit)

a. Reagent Storage Silos:
- Twelve silos capable of storing approximately 14 days of sorbent per unit, 4,200-tons storage total, including substructure
- 14' diameter and 125' high, each
- 350-tons working storage, each
- Continuous level detection systems
- One bin vent filter per silo
- Live bottom hopper outlets
- Rotary airlock assemblies

b. Reagent conveying systems:
- 4 trains (4 x 50%)
- Pneumatic pressure blowers (1 x100% per train)
- One dehumidifier and chiller per train

c. Reagent Milling
- One 7-tph mill per train
- One set of bypass piping per mill

d. Reagent Injection
- Splitters with piping to two APH outlets
- Six injection lances per injection location

e. Concrete foundations including piles for all reagent silo, blower, and mill areas; the approximate footprint for DSI Area is 165’ x 125’

f. Buildings, enclosures, and roofs, including:
   - Blower Building, approximately 25’ x 100’
   - Electrical Building; approximately 15’ x 20’
   - Mill Building; approximately 40 x 80’
   - Dehumidifier Roof; approximately 30’ x 125’
   - Heat Exchanger Roof; approximately 10’ x 80’

g. Geotechnical and subsurface investigation contractor work, including hydro excavation

h. Equipment pricing based on recent vendor pricing for a similar project.

4.2.2 Reagent Handling System

The conceptual design basis for the reagent handling system is to unload two cars at a time. Based on the estimated injection rate and typical railcar capacities, it is anticipated that approximately 20 railcars will be required each week per unit assuming a 100% capacity factor. The reagent handling system includes modification to the existing rail spur on-site to accommodate storage and handling of the reagent railcars. It was assumed that the reagent will be delivered via a 25-car unit train as a maximum. The following equipment and components are included in the cost estimate as part of the reagent handling system:

a. Reagent rail car unloader:
   - System consists of mobile receiving pad and associated vacuum pneumatic connection equipment to unload railcar
   - Enclosed railcar unloading building; approximately 200’ x 75’
   - Trackmobile used to haul and queue the rail cars before and after unloading; capable of moving approximately 25 cars at once.

b. Reagent unloading systems:
   - Two trains (2 x 100%)
   - Pneumatic pressure blowers (1 x 100%) per train
   - One conveying air dehumidifier and chiller per train
   - Pneumatic conveying piping located on an above-grade sleeper pipe rack
   - The equipment pricing included in this estimate is based on recent firm pricing for similar projects. The basis of the conceptual design is a typical UCC arrangement and equipment.

c. Rail track spur extension to north to allow reagent train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs

4.2.3 ESP/Ash Handling Modifications

a. ESP Rebuild – Based on the budgetary quote provided in Attachment 2.

b. Ash Handling Modifications – Equipment pricing based on recent vendor pricing for a similar project.

4.2.4 Civil Work

a. Site grading

b. Soil removal earthwork

c. Excavation, backfill, and compaction for all foundations

d. Development of a new laydown area, approximately 2 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

4.2.5 Mechanical Work

a. Allowance of $975,000 provided for mechanical system including transport piping, pipe rack, instrument/service air and other miscellaneous items based on recent in-house cost estimates for similar projects.

4.2.6 Demolition/Relocation

a. Allowance of $650,000 is provided for demolition and relocation of existing equipment and infrastructure which may interfere with the new DSI system based on recent in-house cost estimates for similar projects.

4.2.7 Electrical

a. Allowance of $3,575,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects.

4.2.8 Instrumentation

a. Allowance of $520,000 provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects.

4.2.9 Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates and fringe benefits and state specific worker's compensation rates as published in the 2016 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. State specific workman's compensation rates are from R.S. Means. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities; and include costs for small tools, construction equipment, insurance, and site overheads.

4.2.10 Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables

b. Premiums and per diems (\$10 per hour)

c. Overtime at five 10-hour shifts per week

d. Freight on construction materials

e. Contractor's General & Administration Fees (included at 10% of total direct costs)

f. Contractor's Profit (included at 5% of total direct costs)

g. Sales tax was included in the cost estimate at 8.125%.

Freight on the DSI System equipment was not included in the cost estimate.

4.2.11 EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be \$4,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of Trona was not included in the EPC Contractor's scope, as this will be supplied by the Owner and is covered as part of the Owner's Costs. The total cost of the initial fills was estimated to be $75,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 150 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $300,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC risk fee is a premium charged by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor. Based on S&L's experience with recent EPC projects, an EPC risk fee was included at 10% of the total EPC project costs.

4.2.12 Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install DSI at White Bluff based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost.

b. Construction Management Support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the construction management support was estimated to be $1,500,000.

c. Startup and Commissioning Support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $300,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
  - Monthly Project Status Meetings
  - Weekly Teleconferences
  - Overall Coordination
  - Project Administration
  - Site Visits and Travel
- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing
- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $1,750,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $175,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of a DSI system at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable O&M costs for each reagent specific system. All of these values, with the exception of the reagent costs, were provided by Entergy. The reagent costs are based on recent pricing received by S&L for another project.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Trona	$/ton	$205
Activated Carbon	$/ton	$1,700
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Fly Ash Revenue	$/ton	$5.85
Aux Power Cost [1]	$/MWh	$41.02

Note 1: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for each case. The reagent consumption rate was developed using a normalized stoichiometric ratio (NSR) of 1.3 which is consistent with test data for similar projects.

Table 4-2: Variable O&M Rates and First Year Costs

	Units	Value
DSI System Parameters		
Reagent Consumption	lb/hr	16,500
Increased Carbon Consumption	lb/hr	210
DSI Waste Production + Increased Carbon + Unsold Fly Ash[3]	lb/hr	40,700
Aux Power Consumption	kW	1,700
Low Quality Water Consumption	gpm	4

	Units	Value
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$10,548,500
Waste Disposal Cost (DSI Waste + Increased Carbon + Unsold Fly Ash)	$/year	$951,900
Increased Carbon Consumption Cost	$/year	$1,113,000
Aux Power Cost	$/year	$434,900
Low Quality Water Cost	$/year	$800
Loss of Fly Ash Sales[3]	$/year	$496,000
Total First Year Variable O&M Cost	**$/year**	**$13,545,100**

Note 1: First year costs are provided in $2016.

Note 2: The first year costs are calculated using an annual capacity factor of 71.2%.

Note 3: Assumes 57% of the station's fly ash was being sold on an annual basis for an average of approximately $5.85 per ton (based on historical data from Entergy).

4.4 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). The recommended staffing additions for the DSI system are 9 personnel for one system.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 0.3% of the project capital. Items such as track work and civil work would be considered high capital cost items with little to no maintenance. Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor[2]	$/year	$1,066,000
Maintenance Material	$/year	$180,000
Maintenance Labor	$/year	$120,000
Total First Year Fixed O&M Cost	**$/year**	**$1,366,000**

Note 1: First year costs are provided in $2016.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on a single unit would require 9 operators total.

5. ATTACHMENTS

1. White Bluff Station DSI System EPC Conceptual Cost Estimate, Sargent & Lundy Estimate No. 34018A
2. ESP Rebuild Budgetary Quote

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Estimator	A. KOCI
Labor rate table	16ARPBL
Project No.	13027-004
Estimate Date	10/20/2016
Reviewed By	MNO
Approved By	MNO
Estimate No.	34018A
Cost index	ARPBL

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
101	UNIT 1 OR 2 (SINGLE UNIT) DSI AREA	3,359,550	15,000,000	527,160	18,441	11,107,036	29,993,746
102	REAGENT HANDLING SYSTEM	1,505,400	1,360,000	1,218,523	26,487	1,956,963	6,040,885
103	ESP/ASH HANDLING MODIFICATIONS	50,000,000	1,050,000		9,885	680,982	51,730,982
104	EARTHWORK			79,496	2,169	183,755	263,251
105	UPGRADE PLANT ENTRANCE						
106	LAYDOWN AREAS			156,000	1,839	146,722	302,722
107	MECHANICAL MISCELLANEOUS	975,000					975,000
108	DEMOLITION / RELOCATION COSTS	650,000					650,000
109	ELECTRICAL	3,575,000					3,575,000
110	INSTRUMENTATION	520,000					520,000
	TOTAL DIRECT	60,584,950	17,410,000	1,981,179	58,822	14,075,457	94,051,586

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	14,075,457		58,822
Material	1,981,179		
Subcontract	60,584,950		
Process Equipment	17,410,000		
	94,051,586	**94,051,586**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	985,000		
91-2 Cost Due To OT 5-10's	1,859,000		
91-4 Per Diem	588,000		
91-5 Consumables	141,414		
91-6 Freight on Material	99,000		
91-8 Sales Tax	2,384,000		
91-9 Contractors G&A	1,990,000		
91-10 Contractors Profit	994,000		
	9,040,414	**103,092,000**	
Indirect Costs:			
93-1 Engineering Services	4,000,000		
93-4 SU/S Parts/ Initial Fills	75,000		
93-5 Technical Field Advisors	300,000		
93-8 EPC Fee	10,747,000		
	15,122,000	**118,214,000**	
Escalation:			
96-1 Escalation on Material	137,000		
96-2 Escalation on Labor	1,693,000		
96-3 Escalation on Subcontract	5,238,000		
96-4 Escalation on Process Eq	926,000		
96-5 Escalation on Indirects	1,261,000		
	9,255,000	**127,469,000**	
Total EPC Cost		***127,469,000***	
Owner's Costs:			
99-1 Owner's Costs	9,457,000		
	9,457,000	**136,926,000**	
Third Party Services:			
100 CM Oversight	1,500,000		
101 Start-Up Oversight	300,000		
102 Owner's Engineer	1,750,000		
103 Performance Testing	175,000		
	3,725,000	**140,651,000**	
Project Contingency :			
110 Project Contingency	32,851,000		
	32,851,000	**173,502,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	960,000		
	960,000	**174,462,000**	
Interest During Construction:			
130 Interest During Constr.	15,649,000		
	15,649,000	**190,111,000**	
Total		***190,111,000***	

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
101			**UNIT 1 OR 2 (SINGLE UNIT) DSI AREA**									
	21.00.00		**CIVIL WORK**									
		21.53.00	**PILING**									
			AUGER CAST GROUT PILE, 18 IN DIA BY 80 FT LONG	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	323.00 EA	1,162,800	-	-		108.88 /MH		1,162,800
			PILE - MOB/DEMOB		1.00 LS	100,000	-			108.88 /MH		100,000
			PILING			**1,262,800**						**1,262,800**
		21.98.00	**CIVIL WORK,TESTING**									
			AUGER CAST GROUT PILE - TESTING		1.00 LS	65,000	-	-		-	-	65,000
			CIVIL WORK,TESTING			**65,000**						**65,000**
			CIVIL WORK			**1,327,800**						**1,327,800**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	2,292.00 CY	-	-	527,160	18,441	60.03 /MH	1,107,036	1,634,196
			CONCRETE					**527,160**	**18,441**		**1,107,036**	**1,634,196**
			CONCRETE					**527,160**	**18,441**		**1,107,036**	**1,634,196**
	23.00.00		**STEEL**									
		23.25.00	**ROLLED SHAPE**									
			BUILDING MIX, TWO COAT PAINTED		TN	-	-			93.00 /MH		
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	BLOWER BUILDING 25 FT X 100 FT	2,500.00 SF	500,000	-			93.00 /MH		500,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	ELECTRICAL BUILDING 15 FT X 20 FT	300.00 SF	105,000	-			93.00 /MH		105,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	MILL BUILDING 40 FT X 80 FT	3,200.00 SF	640,000	-			93.00 /MH		640,000
			SHELL - ROOF ONLY AREA	DEHUMIDIFIER - 30 FT X 125 FT	3,750.00 SF	318,750	-			93.00 /MH		318,750
			SHELL - ROOF ONLY AREA	HEAT EXCHANGER - 10 FT X 80 FT	800.00 SF	68,000	-			93.00 /MH		68,000
			PRE-ENGINEERED BUILDING			**1,631,750**						**1,631,750**
		24.37.00	**ROOFING**									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	DSI AREA ENCLOSURE ROOF	SF	-	-			35.25 /MH		
		24.41.00	**SIDING**									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	DSI AREA ENCLOSURE SIDING	SF	-	-			79.98 /MH		
		24.99.00	**ARCHITECTURAL, MISCELLANEOUS**									
			HEATING	DSI AREA	SF	-	-			64.51 /MH		
			LIGHTING	DSI AREA	SF	-	-			82.56 /MH		
			FIRE PROTECTION	DSI AREA	SF	-	-			82.56 /MH		
			ARCHITECTURAL			**1,631,750**						**1,631,750**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.99.00	**MECHANICAL EQUIPMENT, MISCELLANEOUS**									
			DSI SYSTEM EQUIPMENT	EQUIPMENT COST FOR UNIT 1 OR 2 (SINGLE UNIT)	1.00 LS		15,000,000	-		/MH	10,000,000	25,000,000
			STORAGE SILOS WITH BIN VENT FILTERS (~14 DAYS STORAGE)	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			BLOWERS, HEAT EXCHANGERS, DEHUMIDIFIERS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MILLING EQUIPMENT	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			PIPING SYSTEMS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			COMPRESSORS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			FLOW MODELING	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MECHANICAL EQUIPMENT, MISCELLANEOUS				**15,000,000**				**10,000,000**	**25,000,000**
			MECHANICAL EQUIPMENT				**15,000,000**				**10,000,000**	**25,000,000**
	71.00.00		**PROJECT INDIRECT**									
		71.25.00	**CONSULTANT, THIRD PARTY**									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	250,000	-			/MH		250,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CONSULTANT, THIRD PARTY			400,000						400,000
			PROJECT INDIRECT			400,000						400,000
			101 UNIT 1 OR 2 (SINGLE UNIT) DSI AREA			3,359,550	15,000,000	527,160	18,441		11,107,036	29,993,746
102			REAGENT HANDLING SYSTEM									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	EXTEND REAGENT RAIL TRACK	90,000.00 SF	-	-		207	182.87 /MH	37,835	37,835
			STRIP & STOCKPILE TOPSOIL						207		37,835	37,835
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	EXTEND REAGENT RAIL TRACK	10,000.00 SY	-	-	106,500	345	97.70 /MH	33,690	140,190
			EROSION AND SEDIMENTATION CONTROL					106,500	345		33,690	140,190
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 80 FT LONG	UNLOADING SHED 200' X 75' WIDE	64.00 EA	230,400	-	-	0	108.88 /MH	1	230,401
			PILING			230,400			0		1	230,401
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	EXTEND REAGENT RAIL TRACK	4,500.00 TF	-	-	765,000	7,759	81.75 /MH	634,267	1,399,267
			TRACKWORK					765,000	7,759		634,267	1,399,267
			CIVIL WORK			230,400		871,500	8,310		705,793	1,807,693
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75' WIDE	926.00 CY	-	-	212,980	7,451	60.03 /MH	447,258	660,238
			CONCRETE					212,980	7,451		447,258	660,238
			CONCRETE					212,980	7,451		447,258	660,238
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75' WIDE x 20' TALL	15,000.00 SF	1,275,000	-			93.00 /MH		1,275,000
			PRE-ENGINEERED BUILDING			1,275,000						1,275,000
			ARCHITECTURAL			1,275,000						1,275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			REAGENT PNEUMATIC TRAIN UNLOADING EQUIPMENT		2.00 LS	-	1,000,000	-	6,611	68.89 /MH	455,466	1,455,466
			MATERIAL HANDLING EQUIPMENT				1,000,000		6,611		455,466	1,455,466
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.89 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER	IN UNLOADING SHED 200' X 75' WIDE	1.00 LT	-	135,000	-	1,862	93.00 /MH	173,172	308,172
			RAIL CAR UNLOADER				135,000		1,862		173,172	308,172
			MATERIAL HANDLING EQUIPMENT				1,360,000		8,474		628,638	1,988,638
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	250.00 LF	-	-	10,043	270	77.80 /MH	21,015	31,057
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	1,250.00 LF	-	-	124,000	1,983	77.80 /MH	154,259	278,259
			CARBON STEEL, STRAIGHT RUN					134,043	2,253		175,274	309,316
			PIPING					134,043	2,253		175,274	309,316
			102 REAGENT HANDLING SYSTEM			1,505,400	1,360,000	1,218,523	26,487		1,956,963	6,040,885
103			ESP/ASH HANDLING MODIFICATIONS									
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS									
			ESP EQUIPMENT MODIFICATION	FULL REBUILD OF ESP, INCLUDING INSTALLATION COST	1.00 LS	50,000,000	-	-		68.89 /MH		50,000,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS									
			ASH HANDLING COMPONENT MODIFICATION	ALLOWANCE	1.00 LS		1,050,000	-	9,885	68.89 /MH	680,982	1,730,982
			MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS			50,000,000	1,050,000		9,885		680,982	51,730,982
			MATERIAL HANDLING EQUIPMENT			50,000,000	1,050,000		9,885		680,982	51,730,982
			103 ESP/ASH HANDLING MODIFICATIONS			**50,000,000**	**1,050,000**		**9,885**		**680,982**	**51,730,982**
104			**EARTHWORK**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING ALLOWANCE	30,000.00 SF	-	-		69	182.87 /MH	12,612	12,612
			STRIP & STOCKPILE TOPSOIL - ONSITE	BUILDINGS	600.00 CY	-	-		79	182.87 /MH	14,503	14,503
			STRIP & STOCKPILE TOPSOIL						148		27,115	27,115
		21.17.00	EXCAVATION									
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS	BUILDINGS	2,860.00 CY	-	-		986	79.78 /MH	78,680	78,680
			EXCAVATION						986		78,680	78,680
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING ALLOWANCE	1.00 LT	-	-	44,000	920	72.57 /MH	66,731	110,731
			STORM DRAINAGE UTILITIES					44,000	920		66,731	110,731
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING ALLOWANCE	3,333.00 SY	-	-	35,496	115	97.70 /MH	11,229	46,725
			EROSION AND SEDIMENTATION CONTROL					35,496	115		11,229	46,725
			CIVIL WORK					79,496	2,169		183,755	263,251
			104 EARTHWORK					**79,496**	**2,169**		**183,755**	**263,251**
105			**UPGRADE PLANT ENTRANCE**									
	21.00.00		CIVIL WORK									
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			UPGRADE PLANT ENTRANCE	WORK NOT REQUIRED	0.00 LF	-	-			78.79 /MH		
106			**LAYDOWN AREAS**									
	21.00.00		CIVIL WORK									
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	2.00 AC	-	-	156,000	1,839	79.78 /MH	146,722	302,722
			CIVIL WORK, MISCELLANEOUS					156,000	1,839		146,722	302,722
			CIVIL WORK					156,000	1,839		146,722	302,722
			106 LAYDOWN AREAS					**156,000**	**1,839**		**146,722**	**302,722**
107			**MECHANICAL MISCELLANEOUS**									
	31.00.00		MECHANICAL EQUIPMENT									
		31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS									
			MECHANICAL EQUIPMENT	INCLUDES PIPE RACK - ALLOWANCE SUBCONTRACT COST	1.00 LS	975,000	-	-		68.89 /MH		975,000
			MECHANICAL EQUIPMENT, MISCELLANEOUS			975,000						975,000
			MECHANICAL EQUIPMENT			975,000						975,000
			107 MECHANICAL MISCELLANEOUS			**975,000**						**975,000**
108			**DEMOLITION / RELOCATION COSTS**									
	11.00.00		DEMOLITION									
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION AND RELOCATION	ALLOWANCE - SUBCONTRACT COST	1.00 LS	650,000	-			107.47 /MH		650,000
			DEMOLITION, MISCELLANEOUS			650,000						650,000
			DEMOLITION			650,000						650,000
			108 DEMOLITION / RELOCATION COSTS			**650,000**						**650,000**
109			**ELECTRICAL**									
	41.00.00		ELECTRICAL EQUIPMENT									
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS	ALLOWANCE - SUBCONTRACT COST	1.00 LS	3,575,000	-			64.04 /MH		3,575,000
			ELECTRICAL EQUIPMENT, MISCELLANEOUS			3,575,000						3,575,000
			ELECTRICAL EQUIPMENT			3,575,000						3,575,000
			109 ELECTRICAL			**3,575,000**						**3,575,000**
110			**INSTRUMENTATION**									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.99.00	CONTROL & INSTRUMENTATION, ALLOWANCE									
			CONTROL & INSTRUMENTATION	ALLOWANCE - SUBCONTRACT COST	1.00 LS	520,000	-			65.15 /MH		520,000
			CONTROL & INSTRUMENTATION, ALLOWANCE			520,000						520,000
			CONTROL & INSTRUMENTATION			520,000						520,000
			110 INSTRUMENTATION			**520,000**						**520,000**

27881 Clemens Road
Westlake, OH 44145
Phone: 440.899.3888
Fax: 440.899.3890

October 17, 2016

Sargent & Lundy
Attention: Danielle Flagg
55 East Monroe Street
Chicago, IL 60603

Subject: Fuel Tech, Inc. (FTI) Estimate #16-B-111 Rev1
Confidential Client ESP Retrofit
High Level Estimate

Dear Ms. Flagg,

In response to Sargent & Lundy's (S&L)'s recent request, Fuel Tech, Inc. (FTI), has assembled a high level estimate for the materials and installation necessary to retrofit Sargent & Lundy's "Confidential Client" Electrostatic Precipitators. Please consider the pricing as +/- 30% for high level budgetary estimation purposes.

The ESPs have been evaluated by our engineering staff and the estimate includes the most comprehensive improvements possible. Improvements that we have included in the estimate to increase performance and reliability include all new internals; collecting plates at 16" wide plate spacing, rigid discharge electrodes, top-rapped MIGI rapper conversion with increased rapping sectionalization, increased high voltage frame electrical sectionalization, and the addition of high frequency power supplies.

The estimates and information provided above are based upon FTI's historical information and experience, and should be used for accounting purposes ONLY. Should S&L want to move forward with a more in-depth budgetary proposal, FTI can provide such a document with additional lead-time. Thank you for your interest in our products and services, and we will continue to support Sargent & Lundy's efforts in any way practical for this and other opportunities. Should you require any additional information regarding this submittal, please contact me directly.

Respectfully,

Dustin Ekey
Regional Sales Manager

FTI Budgetary Proposal #16-B-111 Rev 1

Sargent & Lundy Confidential Client ESP Retrofit

Submitted by:

27881 Clemens Road
Westlake, Ohio 44145
P: 440.539.8792
www.ftek.com

EXECUTIVE SUMMARY

<u>Sargent & Lundy – Confidential Client ESP Rebuild Budgetary Request:</u>

In accordance with Sargent & Lundy's RFQ dated September 30, 2016, Fuel Tech, Inc. (FTI) has provided a high level estimate based on historical data to engineer, design, supply, and deliver an ESP Retrofit based on the provided information as follows;

A confidential client is currently evaluating the costs associated with rebuilding an existing ESP. As part of this project, the client will potentially be installing dry sorbent injection (DSI) upstream of the upgraded ESP.

The following summarizes the ESP design of the unit being evaluated:

- PC Walther original OEM installed in the early 1980s.
- Consists of four (4) identical ESP casings, with two (2) casings on top of the other two (2) casings; AKA "Piggybacked".
- Each ESP casing has eight (8) mechanical fields, two (2) mechanical fields wide by four (4) mechanical fields deep.
- Each field is 14' in length and contains forty-four (44) collecting electrodes with forty-three (43) gas passages.
- The collecting electrodes are 48' in height with 12" plate spacing.
- The total collecting surface area is 1,900,000 ft^2.
- Design flue gas flowrate is approximately 3,500,000 acfm, and a design velocity of 5 feet per second.
- The SCA of the existing ESP is approximately 540 ft^2/MMacfm.
- The overall dimension for each ESP is approximately 85'L x 90'W x 50'H.
- Each gas passage has discharge frame electrodes.
- The system is equipped with a Walther tumbling hammer rapper system.
- There are eight (8) T/R sets on each ESP, with a total of thirty-two (32).

ESP rebuild design and performance considerations:

- Achieve an outlet PM emissions rate of 0.015 lb/MMBtu or lower.
- Design inlet ash loading of 55,000 lb/hr.
- Non-halogenated PAC is injected at 150 lb/hr.
- Trona will be injected at 22,500 lb/hr, resulting in an increased particulate loading of 18,200 lb/hr to the ESP.
- Inlet flue gas temperature up to 315 deg F.

Fuel Tech, Inc. – Retrofitted ESP Arrangement and Summary:

While the existing ESPs are considered to be relatively large by industry standards, the design information provided shows that 22,500 lb/hr of Trona will be injected in addition to the existing inlet ash loading is 55,000 lb/hr. With this being said, while the ESPs are large they are still an efficiency machine and overcoming the new total inlet loading of over 73,000 lb/hr will be extremely difficult to achieve the requested 0.015 lbs/MMbtu outlet PM emissions, without retrofitting the entire ESPs to BART technology. Essentially, the ESPs will need to be rebuilt to "as-new" condition with the most state-of-the-art technology options. At the very least, new internals and electrical control systems would require new:

- Assembled Panel Collecting Electrodes
- Rigid Discharge Electrodes
- Top-Rapped MIGI Style Rapper Conversion
- All new Hot Roof, Cold Roof, and Penthouse
- Heated Purge Air Systems
- High Frequency Switch-Mode Power Supplies (SMPS)
- New Access Doors
- All new 3-Phase Electrical Supply Wiring
- New Controllers
- New Hopper Arrangement

Retrofit ESP Arrangement; Quantities are for one (1) ESP, there are four (4) ESPs total:

Number of ESP's / Unit:	4
Mechanical Fields & Size / ESP:	6 @ 9'
Electrical Fields & Size / ESP:	12 @ 4.5'
Chambers / ESP:	2
Gas Passages / Chamber:	33
Collecting Plates / Chamber:	32
Collecting Plate Height:	44'
Plate Spacing:	16"
RDE's / ESP:	1,536
Rapping Arrangment:	Top Rapped – MIGI
Collecting System Rappers / ESP:	176
Discharge System Rappers / ESP:	48
High Frequency Power Supplies / ESP:	16

The amount of planning, engineering, material supply, installation, and installation oversight necessary for a project listed above will be very significant. Pricing estimation can be found below.

High-Level Pricing Estimation for one (1) Confidential Unit including all four (4) ESPs:

Pricing estimate is based upon +/- 30%

The total budgetary estimate to provide ESP materials and engineering: **$ 20,000,000.00**

The total budgetary estimate to provide non-union installation: **$ 30,000,000.00**

*Note: The estimates and information provided above are based upon FTI's historical information and experience, and should be used for accounting purposes ONLY. Should S&L want to move forward with a more in-depth budgetary proposal, FTI can provide such a document with additional lead-time.

ENTERGY ARKANSAS, INC.

WHITE BLUFF

ENHANCED DSI COST ESTIMATE BASIS DOCUMENT

SL-014001
Final, Rev. 0
August 3, 2017
Project 13027-002

Prepared by

Sargent & Lundy LLC

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CONTENTS

1. PURPOSE

Entergy has requested that Sargent & Lundy (S&L) evaluate installation of an enhanced dry sorbent injection (DSI) system utilizing a baghouse in conjunction with the DSI system at White Bluff to control sulfur dioxide (SO_2) emissions. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) and the capital cost estimates.

2. TECHNOLOGY DESCRIPTION

DSI is a proven technology, which has only recently been implemented, for moderate removal of $SO_2$and other acid gases from coal-fired power plants. It involves injection of sodium-based sorbents into the ductwork after the boiler and prior to the particulate collection device. DSI is considered a relatively low capital cost, moderate SO_2 removal alternative to wet or dry FGD systems. No slurry equipment or separate reactor vessel is required with a DSI system. With the proper temperature profile and stoichiometry, the sorbent can effectively react with $SO_2$and other acid gases in the flue gas. The resulting particulate matter is removed from the flue gas by a particulate collection device, typically an existing electrostatic precipitator (ESP). The performance of DSI technology has been shown to be enhanced by implementation with a downstream fabric filter or baghouse. A baghouse increases the overall residence time due to longer ductwork and additional contact through the filter cake which builds up on the bags. The additional residence time improves performance and in some applications has resulted in much higher achievable removal efficiencies than traditional DSI technology upstream of an existing ESP.

The typical DSI sorbents include sodium bicarbonate ($NaHCO_3$) and Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$). Sorbent injection into the ductwork (downstream of the boiler and upstream of the ESP or baghouse) has been tested in the industry using sodium-based sorbents. The process works through neutralization of SO_2 and other acid gases with the caustic sorbent; the neutralization occurs as long as the sorbent remains in contact with the gas. Sorbent injection has been proven effective on a variety of pulverized coal-fired boilers using a range of low to high sulfur coals. It is considered a commercial technology although with a limited supplier base due to the historically limited interest.

The DSI process produces a dry byproduct which can be landfilled. The waste products will contain sodium sulfate and sulfite ($NaSO_3/NaSO_4$) along with the unused sorbent and the normal fly ash. These wastes will be collected in a baghouse and can be transported with conventional pneumatic fly ash handling equipment. The waste from sodium-based sorbents will have relatively high concentrations of soluble salts, which may affect the byproduct handling. With the addition of dry sorbent byproducts fly ash cannot be sold for reuse.

3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the DSI technology supplier providing the main process equipment, including reagent storage, milling, conveyance, injection lances, baghouse, and booster fans.
- Installation of a pulse jet fabric filter (PJFF) downstream of the existing ESPs to assist in SO_2 removal efficiency and capture of the DSI byproduct.
- Installation of new booster fans to account for increased draft pressure loss mainly due to the baghouse.
- Reagent injection at the ESP outlet, upstream of a new baghouse to collect flyash separately and preserve flyash sales
- On-site disposal of DSI byproduct, including flyash blending equipment for stabilization.
- Reagent injection rates based on 80% SO_2 removal from a design inlet concentration of 0.76 lb SO_2/MMBtu, based on the highest 5% of SO_2 emissions from 2009 through 2013.
  - Annual operating costs will be based on 80% SO_2 removal from an uncontrolled SO_2 rate of 0.57 lb SO_2/MMBtu, based on the annual heat input weighted average emission from 2009 through 2013.
  - The system will be designed to control emissions to meet a permit limit of 0.15 lb/MMBtu on a 30-boiler day rolling average, based on a maximum 30-day average SO_2 emission rate of 0.66 lb/MMBtu from 2009 through 2013.
- Trona was used as the DSI reagent for the purposes of this estimate.

- A high level conceptual system design, based on the estimated injection rate, was used as input to the Enhanced DSI cost estimate. The following were estimated based on previous projects and scaled for the predicted dry sorbent injection rate for White Bluff:
  - Auxiliary power consumption
  - Annual reagent consumption
  - Additional carbon consumption
  - Additional water consumption
  - Additional waste production
  - Reagent storage silos
  - Quantity of mills
  - Quantity of blower trains

The fabric filter and ID fan equipment costs are scaled based on flue gas volume in comparison to industry data and recent budgetary cost estimates.

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs
- Freight
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills (other than reagent)
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 34019A provided in Attachment 1 represents the total cost to Entergy to install Enhanced DSI technology on a single unit at White Bluff (Unit 1 or 2) including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Waste disposal (DSI waste)
- Reagent consumption
- Auxiliary power consumption
- Low quality water consumption for mill cleaning
- PJFF bag and cage replacement
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Cost Estimate and Capital Cost Estimate 34019A were developed using the assumptions and scope provided in this document. The project definition and accuracy corresponds to a study level estimate as defined in U.S.EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. The costs provided in this report are in 2016 dollars.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

4.1 DESIGN INPUTS AND ASSUMPTIONS

The following assumptions were made for the design basis for the White Bluff DSI Systems:

- Design SO_2 inlet concentration of 0.76 lb SO_2/MMBtu.
- SO_2 inlet concentration of 0.57 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 removal efficiency of 80%
- Annual capacity factor of 72.1% (annual average capacity factor for White Bluff Units 1 and 2 based on historical heat input from 2009 through 2013).
- Reagent injection at the ESP outlet, upstream of the new baghouse.
- Reagent delivery by rail.
- Compliance deadline of three years from the effective date of the rule.

Before proceeding with a DSI project, a demonstration test should be completed at White Bluff to confirm the feasibility of DSI technology at White Bluff and quantify the potential BOP impacts associated with the project, such as leachability of the byproduct.

4.1.1 Landfill Modifications

The sodium byproducts (salts) that are produced when Trona reacts with SO_2 and other acid gases, along with the unreacted sorbent are soluble in water. The resulting waste collected in the particulate collection device will need to be disposed of in a landfill that is lined and has a leachate collection system. With the addition of DSI, White Bluff will no longer be able to sell their fly ash for beneficial re-use due to the solubility of the sodium salts which would be present in the waste. The cost to maintain a landfill and open new cells is included in the typical maintenance budget of a plant. It was assumed, that any future landfill cells would include lining and leachate collection; therefore, no landfill modifications will be required to accommodate the addition of DSI and no costs were included in this estimate.

4.2 TOTAL INSTALLED CAPITAL INVESTMENT

The DSI system supplier will provide all of the equipment related to storing, milling, conveying and injecting the reagent; in this case, the system is designed for Trona. The baghouse area equipment, ID fan equipment, and the remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DSI system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by the following areas:

4.2.1 DSI Area (Single Unit)

a. Reagent Storage Silos:
- Twenty silos capable of storing approximately 14 days of sorbent per unit, 7,000-tons storage total, including substructure
- 14' diameter and 125' high, each
- 350-tons working storage, each
- Continuous level detection systems
- One bin vent filter per silo
- Live bottom hopper outlets
- Rotary airlock assemblies

b. Reagent conveying systems:
- 5 trains (5 x 33%)
- Pneumatic pressure blowers (1 x100% per train)
- One dehumidifier and chiller per train

c. Reagent Milling
- One 7-tph mill per train
- One set of bypass piping per mill

d. Reagent Injection
   - Splitters with piping to two ESP outlets
   - Six injection lances per injection location

e. Concrete foundations including piles for all reagent silo, blower, and mill areas; the approximate footprint for DSI Area is 160’ x 200’

f. Buildings, enclosures, and roofs, including:
   - Blower Building, approximately 25’ x 125’
   - Electrical Building; approximately 30’ x 20’
   - Mill Building; approximately 50’ x 100’
   - Dehumidifier Roof; approximately 30’ x 160’
   - Heat Exchanger Roof; approximately 10’ x 100’

g. Geotechnical and subsurface investigation contractor work, including hydro excavation

h. Equipment pricing based on recent vendor pricing for a similar project.

4.2.2 Reagent Handling System

The conceptual design basis for the reagent handling system is to unload three cars at a time. Based on the estimated injection rate and typical railcar capacities, it is anticipated that approximately 35 railcars will be required each week per unit assuming a 100% capacity factor. The reagent handling system includes modification to the existing rail spur on-site to accommodate storage and handling of the reagent railcars. It was assumed that the reagent will be delivered via a 25-car unit train as a maximum. The following equipment and components are included in the cost estimate as part of the reagent handling system:

a. Reagent rail car unloader:
   - System consists of mobile receiving pad and associated vacuum pneumatic connection equipment to unload railcar
   - Enclosed railcar unloading building; approximately 300’ x 75’
   - Trackmobile used to haul and queue the rail cars before and after unloading; capable of moving approximately 25 cars at once.

b. Reagent unloading systems:
   - Three trains (3 x 100%)
   - Pneumatic pressure blowers (1 x 100%) per train
   - One conveying air dehumidifier and chiller per train

- Pneumatic conveying piping located on an above-grade sleeper pipe rack
- The equipment pricing included in this estimate is based on recent firm pricing for similar projects. The basis of the conceptual design is a typical UCC arrangement and equipment.

c. Rail track spur extension to north to allow reagent train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs

4.2.3 Byproduct Handling

a. Two DSI by-product storage silos (approximately 7-day capacity) with bin vent filter, fluidizing system, and four unloading conditioners (pin mixers)

b. One common fly ash blending bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

c. Water pumps and associated piping for unloading conditioners at both silos

d. Compressed air system for air operated valves

e. Storage silo substructure and superstructure

f. Concrete foundations including piles for silos

g. Continuous level detection system

h. One lot pneumatic conveying piping located on an above grade pipe rack

i. Two truck scales and substructure

j. Cost estimate based on a recent budgetary proposal for similar project

4.2.4 Baghouse Area

a. New baghouse, including pulse jet cleaning system and all appurtenances

b. Two casings with 8 compartments

c. 10 meter bags and cages

d. 6” insulation with lagging

e. Enclosure around hopper area

f. Baghouse area foundations including 18” auger cast piles 60’ long

g. Equipment pricing based on recent pricing for similar projects

4.2.5 Ductwork and Supports

a. ID fan outlet to Baghouse inlet:

- Two ID fan outlet ducts, combine to a single duct to carry flue gas to the new baghouse
- Carbon steel, ¼ in.
- Velocity, 3,600 fpm

b. Baghouse outlet to Booster fans
   - A single baghouse outlet duct which splits into two booster fan inlets.
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm

c. Booster fan outlet to the stack inlet ductwork and supports:
   - Two booster fan inlets, combine to a single duct which connects to the existing chimney breeching duct.
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm

d. Dampers and expansion joints

e. 6" insulation and lagging

f. Steel support structure and concrete mat foundations for all new flue gas ductwork

4.2.6 ID Booster Fans

a. Two, approximately 4,000 hp, axial booster fans sized to overcome pressure drop associated with baghouse

b. Includes motors - no spare motor included

c. Booster fan area foundations

4.2.7 Civil Work

a. Site grading

b. Soil removal earthwork

c. Excavation, backfill, and compaction for all foundations

d. Development of a new laydown area, approximately 4 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

4.2.8 Mechanical Work

a. Allowance of $2,600,000 provided for mechanical system including transport piping, pipe rack, instrument/service air and other miscellaneous items based on recent in-house cost estimates for similar projects.

4.2.9 Demolition/Relocation

a. Allowance of $975,000 is provided for demolition and relocation of existing equipment and infrastructure which may interfere with the new DSI system based on recent in-house cost estimates for similar projects.

4.2.10 Electrical

a. Allowance of $16,250,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects.

4.2.11 Instrumentation

a. Allowance of $2,210,000 provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects.

4.2.12 Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates and fringe benefits and state specific worker's compensation rates as published in the 2016 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. State specific workman's compensation rates are from R.S. Means. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities; and include costs for small tools, construction equipment, insurance, and site overheads.

4.2.13 Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables

b. Premiums and per diems ($10 per hour)

c. Overtime at five 10-hour shifts per week

d. Freight on construction materials

e. Contractor's General & Administration Fees (included at 10% of total direct costs)

f. Contractor's Profit (included at 5% of total direct costs)

g. Sales tax was included at 8.125%.

Freight on the DSI System equipment was not included in the cost estimate.

4.2.14 EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $10,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of Trona was not included in the EPC Contractor's scope, as this will be supplied by the Owner and is covered as part of the Owner's Costs. The total cost of the initial fills was estimated to be $150,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 200 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $400,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC risk fee is a premium charged by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor. Based on S&L's experience with recent EPC projects, an EPC risk fee was included at 10% of the total EPC project costs.

4.2.15 Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install DSI at White Bluff based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost.

b. Construction Management Support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the construction management support was estimated to be $2,500,000.

c. Startup and Commissioning Support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $350,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
    - Monthly Project Status Meetings
    - Weekly Teleconferences
    - Overall Coordination
    - Project Administration
    - Site Visits and Travel

- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing
- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $2,750,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $175,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of a DSI system at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable O&M costs for each reagent specific system. All of these values, with the exception of the reagent costs, were provided by Entergy. The reagent costs are based on recent pricing received by S&L for another project.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Trona	$/ton	$205
Low Quality Water	$/1000 gal	$0.53
Bag Cost [1]	$/bag	100.00
Cage Cost [1]	$/cage	30.00
Waste Disposal	$/ton	$7.50
Aux Power Cost [2]	$/MWh	$41.02

Note 1: Bags will be replaced every 3 years and cages will be replaced every 9 years.

Note 2: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for each case. The reagent consumption rate was developed using a normalized stoichiometric ratio (NSR) of 2.4 which is consistent with test data for similar projects.

Table 4-2: Variable O&M Rates and First Year Costs

	Units	Value
DSI System Parameters		
Reagent Consumption	lb/hr	30,400
DSI Waste Production	lb/hr	24,100
Aux Power Consumption	kW	8,800
Low Quality Water Consumption	gpm	6
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$19,434,900
Waste Disposal Cost	$/year	$563,700
Aux Power Cost	$/year	$2,251,500
Low Quality Water Cost	$/year	$1,200
Bag and Cage Replacement Cost	$/year	$1,796,000
Total First Year Variable O&M Cost	**$/year**	**$24,047,300**

Note 1: First year costs are provided in $2016.

Note 2: The first year costs are calculated using an annual capacity factor of 72.1%.

4.4 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). The recommended staffing additions for the DSI system are 9 personnel for one system.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 0.5% of the project capital. Items such as track work and civil work would be considered high capital cost items with little to no maintenance.

Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs

First Year[1] Fixed O&M Costs	Units	Value
Operating Labor[2]	$/year	$1,066,000
Maintenance Material	$/year	$645,000
Maintenance Labor	$/year	$430,000
Total First Year Fixed O&M Cost	**$/year**	**$2,141,000**

Note 1: First year costs are provided in $2016.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on a single unit would require 9 operators total.

5. ATTACHMENTS

1. White Bluff Station Enhanced DSI System EPC Conceptual Cost Estimate, Sargent & Lundy Estimate No. 34019A

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Estimator	A. KOCI
Labor rate table	16ARPBL
Project No.	13027-004
Estimate Date	10/20/2016
Reviewed By	MNO
Approved By	MNO
Estimate No.	34019A
Cost index	ARPBL

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
101	UNIT 1 OR 2 (SINGLE UNIT) DSI AREA	4,693,000	20,500,000	817,880	28,611	15,417,548	41,428,428
102	REAGENT HANDLING SYSTEM	2,258,100	2,445,000	1,325,013	35,380	2,581,496	8,609,609
103	BYPRODUCT HANDLING SYSTEM	7,713,100	6,872,000	853,055	76,615	5,670,075	21,108,230
104	UNIT 1 OR 2 FLUE GAS SYSTEM	496,800	240,000	8,136,840	162,932	14,173,748	23,047,388
105	UNIT 1 OR 2 BOOSTER FANS		5,400,000	212,595	27,391	1,888,104	7,500,699
106	UNIT 1 OR 2 BAGHOUSE	1,173,600	20,000,000	3,638,113	85,175	19,008,734	43,820,447
107	EARTHWORK			2,021,832	44,398	5,879,245	7,901,077
108	LAYDOWN AREAS			312,000	3,678	293,444	605,444
109	MECHANICAL MISCELLANEOUS	2,600,000					2,600,000
110	DEMOLITION/RELOCATION	975,000					975,000
111	ACI RELOCATION	100,000		146,775	1,954	135,859	382,635
112	ELECTRICAL	16,250,000					16,250,000
113	INSTRUMENTATION	2,210,000					2,210,000
	TOTAL DIRECT	38,469,600	55,457,000	17,464,103	466,134	65,048,253	176,438,956

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
ENHANCED DSI SYSTEM W/BAGHOUSE EPC

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	65,048,253		466,134
Material	17,464,103		
Subcontract	38,469,600		
Process Equipment	55,457,000		
	176,438,956	**176,438,956**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	4,553,000		
91-2 Cost Due To OT 5-10's	8,760,000		
91-4 Per Diem	4,661,000		
91-5 Consumables	650,044		
91-6 Freight on Material	873,000		
91-8 Sales Tax	2,897,000		
91-9 Contractors G&A	10,350,000		
91-10 Contractors Profit	5,175,000		
	37,919,044	**214,358,000**	
Indirect Costs:			
93-1 Engineering Services	10,000,000		
93-4 SU/S Parts/ Initial Fills	150,000		
93-5 Technical Field Advisors	400,000		
93-8 EPC Fee	22,491,000		
	33,041,000	**247,399,000**	
Escalation:			
96-1 Escalation on Material	1,212,000		
96-2 Escalation on Labor	8,026,000		
96-3 Escalation on Subcontract	3,326,000		
96-4 Escalation on Process Eq	2,948,000		
96-5 Escalation on Indirects	2,756,000		
	18,268,000	**265,667,000**	
Total EPC Cost		***265,667,000***	
Owner's Costs:			
99-1 Owner's Costs	19,792,000		
	19,792,000	**285,459,000**	
Third Party Services:			
100 CM Oversight	2,500,000		
101 Start-Up Oversight	350,000		
102 Owner's Engineer	2,750,000		
103 Performance Testing	175,000		
	5,775,000	**291,234,000**	
Project Contingency :			
110 Project Contingency	68,242,000		
	68,242,000	**359,476,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	1,893,000		
	1,893,000	**361,369,000**	
Interest During Construction:			
130 Interest During Constr.	32,375,000		
	32,375,000	**393,744,000**	
Total		***393,744,000***	

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
101			**UNIT 1 OR 2 (SINGLE UNIT) DSI AREA**									
	21.00.00		**CIVIL WORK**									
		21.53.00	**PILING**									
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	500.00 EA	1,800,000	-	-		108.88 /MH		1,800,000
			PILE - MOB/DEMOB		1.00 LS	100,000	-			108.88 /MH		100,000
			PILING			**1,900,000**						**1,900,000**
		21.98.00	**CIVIL WORK,TESTING**									
			AUGER CAST GROUT PILE - TESTING		1.00 LS	65,000	-	-		-	-	65,000
			CIVIL WORK,TESTING			**65,000**						**65,000**
			CIVIL WORK			**1,965,000**						**1,965,000**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	3,556.00 CY	-	-	817,880	28,611	60.03 /MH	1,717,548	2,535,428
			CONCRETE					**817,880**	**28,611**		**1,717,548**	**2,535,428**
			CONCRETE					**817,880**	**28,611**		**1,717,548**	**2,535,428**
	23.00.00		**STEEL**									
		23.25.00	**ROLLED SHAPE**									
			BUILDING MIX, TWO COAT PAINTED		TN	-	-			93.00 /MH		
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	BLOWER BUILDING 25 FT X 125 FT	3,125.00 SF	625,000	-			93.00 /MH		625,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	ELECTRICAL BUILDING 30 FT X 20 FT	600.00 SF	210,000	-			93.00 /MH		210,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	MILL BUILDING 50 FT X 100 FT	5,000.00 SF	1,000,000	-			93.00 /MH		1,000,000
			SHELL - ROOF ONLY AREA	DEHUMIDIFIER - 30 FT X 160 FT	4,800.00 SF	408,000	-			93.00 /MH		408,000
			SHELL - ROOF ONLY AREA	HEAT EXCHANGER - 10 FT X 100 FT	1,000.00 SF	85,000	-			93.00 /MH		85,000
			PRE-ENGINEERED BUILDING			**2,328,000**						**2,328,000**
		24.37.00	**ROOFING**									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	DSI AREA ENCLOSURE ROOF	SF	-	-			35.25 /MH		
		24.41.00	**SIDING**									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	DSI AREA ENCLOSURE SIDING	SF	-	-			79.98 /MH		
		24.99.00	**ARCHITECTURAL, MISCELLANEOUS**									
			HEATING	DSI AREA	SF	-	-			64.51 /MH		
			LIGHTING	DSI AREA	SF	-	-			82.56 /MH		
			FIRE PROTECTION	DSI AREA	SF	-	-			82.56 /MH		
			ARCHITECTURAL			**2,328,000**						**2,328,000**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.99.00	**MECHANICAL EQUIPMENT, MISCELLANEOUS**									
			DSI SYSTEM EQUIPMENT	EQUIPMENT COST FOR UNIT 1 OR 2 (SINGLE UNIT)	1.00 LS		20,500,000	-		/MH	13,700,000	34,200,000
			STORAGE SILOS WITH BIN VENT FILTERS (~14 DAYS STORAGE)	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			BLOWERS, HEAT EXCHANGERS, DEHUMIDIFIERS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MILLING EQUIPMENT	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			PIPING SYSTEMS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			COMPRESSORS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			FLOW MODELING	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MECHANICAL EQUIPMENT, MISCELLANEOUS				**20,500,000**				**13,700,000**	**34,200,000**
			MECHANICAL EQUIPMENT				**20,500,000**				**13,700,000**	**34,200,000**
	71.00.00		**PROJECT INDIRECT**									
		71.25.00	**CONSULTANT, THIRD PARTY**									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	250,000	-			/MH		250,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CONSULTANT, THIRD PARTY			400,000						400,000
			PROJECT INDIRECT			400,000						400,000
			101 UNIT 1 OR 2 (SINGLE UNIT) DSI AREA			**4,693,000**	**20,500,000**	**817,880**	**28,611**		**15,417,548**	**41,428,428**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	EXTEND REAGENT RAIL TRACK	90,000.00 SF	-	-		207	182.87 /MH	37,835	37,835
			STRIP & STOCKPILE TOPSOIL						207		37,835	37,835
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	EXTEND REAGENT RAIL TRACK	10,000.00 SY	-	-	106,500	345	97.70 /MH	33,690	140,190
			EROSION AND SEDIMENTATION CONTROL					106,500	345		33,690	140,190
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG	UNLOADING SHED 300' X 75' WIDE	96.00 EA	345,600	-	-		108.88 /MH		345,600
			PILING			345,600						345,600
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	EXTEND REAGENT RAIL TRACK	4,500.00 TF	-	-	765,000	7,759	81.75 /MH	634,267	1,399,267
			TRACKWORK					765,000	7,759		634,267	1,399,267
			CIVIL WORK			345,600		871,500	8,310		705,792	1,922,892
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 300' X 75' WIDE	1,389.00 CY	-	-	319,470	11,176	60.03 /MH	670,887	990,357
			CONCRETE					319,470	11,176		670,887	990,357
			CONCRETE					319,470	11,176		670,887	990,357
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 300' X 75' WIDE x 20' TALL	22,500.00 SF	1,912,500	-			93.00 /MH		1,912,500
			PRE-ENGINEERED BUILDING			1,912,500						1,912,500
			ARCHITECTURAL			1,912,500						1,912,500
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			REAGENT PNEUMATIC TRAIN UNLOADING EQUIPMENT		3.00 LS	-	1,500,000	-	9,917	68.89 /MH	683,199	2,183,199
			MATERIAL HANDLING EQUIPMENT				1,500,000		9,917		683,199	2,183,199
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	3.00 EA	-	675,000	-		68.89 /MH		675,000
			MOBILE YARD EQUIPMENT				675,000					675,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER	IN UNLOADING SHED 300' X 75' WIDE	2.00 LT	-	270,000	-	3,724	93.00 /MH	346,345	616,345
			RAIL CAR UNLOADER				270,000		3,724		346,345	616,345
			MATERIAL HANDLING EQUIPMENT				2,445,000		13,641		1,029,544	3,474,544
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	250.00 LF	-	-	10,043	270	77.80 /MH	21,015	31,057
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	1,250.00 LF	-	-	124,000	1,983	77.80 /MH	154,259	278,259
			CARBON STEEL, STRAIGHT RUN					134,043	2,253		175,274	309,316
			PIPING					134,043	2,253		175,274	309,316
			102 REAGENT HANDLING SYSTEM			**2,258,100**	**2,445,000**	**1,325,013**	**35,380**		**2,581,496**	**8,609,609**
103			**BYPRODUCT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ASH SILO AND DSI BYPRODUCT SILOS	125.00 EA	-	-	232,125	3,161	108.88 /MH	344,161	576,286
			CAISSON					232,125	3,161		344,161	576,286

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK					**232,125**	**3,161**		**344,161**	**576,286**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	DSI BYPRODUCT SILOS	614.00 CY	-	-	141,220	4,940	60.03 /MH	296,562	437,782
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FLY ASH BLENDING SILO	67.00 CY	-	-	15,410	539	60.03 /MH	32,361	47,771
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	FOR TRUCK SCALES	144.00 CY	-	-	33,120	1,159	60.03 /MH	69,552	102,672
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	MISC	100.00 CY	-	-	23,000	805	60.03 /MH	48,300	71,300
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	60.03 /MH	2,898	4,278
			CONCRETE					**214,130**	**7,491**		**449,673**	**663,803**
			CONCRETE					**214,130**	**7,491**		**449,673**	**663,803**
	23.00.00		**STEEL**									
		23.13.75	**SILO**									
			NEW 250 TON FLYASH BLENDING BIN SILO - 24FT DIA X 72 FT HIGH - ERECTION AND FREIGHT INCLUDED	SILO	1.00 EA		275,000		2,839	73.51 /MH	208,701	483,701
			SILO				**275,000**		**2,839**		**208,701**	**483,701**
			STEEL				**275,000**		**2,839**		**208,701**	**483,701**
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			PRE-ENGINEERED BUILDING	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	93.00 /MH	10,690	20,690
			PRE-ENGINEERED BUILDING					**10,000**	**115**		**10,690**	**20,690**
			ARCHITECTURAL					**10,000**	**115**		**10,690**	**20,690**
	26.00.00		**MISCELLANEOUS STRUCTURAL ITEM**									
		26.13.00	**CONCRETE SILO**									
			CONCRETE SILO - DSI BYPRODUCT SILO	ERECTED - 52' DIA	2.00 LS	7,600,000				60.03 /MH		7,600,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	10,000			73.51 /MH		10,000
			CONCRETE SILO - FREIGHT		1.00 LS	-	70,000			73.51 /MH		70,000
			CONCRETE SILO			**7,600,000**	**80,000**		**0**			**7,680,000**
			MISCELLANEOUS STRUCTURAL ITEM			**7,600,000**	**80,000**		**0**			**7,680,000**
	33.00.00		**MATERIAL HANDLING EQUIPMENT**									
		33.13.00	**BYPRODUCT HANDLING EQUIPMENT**									
			PNEUMATIC ASH CONVEYORS	EQUIPMENT INCLUDES FREIGHT	1.00 LS	-	5,655,000	-		73.51 /MH		5,655,000
			PNEUMATIC ASH CONVEYORS	INSTALLATION COST	1.00 LT	-		-	51,910	73.51 /MH	3,815,929	3,815,929
			BLOWERS, PRESSURE FEEDERS, TRANSPORT PIPING AND VACUUM / PRESSURE RELIEF VALVES	INCLUDED ABOVE	1.00 LT	-		-		73.51 /MH		
			-DRY UNLOADING SPOUT BELOW THE PRODUCT SILO		2.00 EA	-	60,000	-	258	73.51 /MH	18,977	78,977
			AIRSLIDE CONVEYORS FROM BLENDING BIN MIXER/PIPE CONVEYOR, INCL ALL VALVES AND ACCESSORIES		4.00 EA	-	80,000	-	688	73.51 /MH	50,595	130,595
			-FOUR PIN MIXERS BELOW CONCRETE SILOS INCL ALL VALVES AND ACCESSORIES		1.00 LT	-	540,000	-	3,347	73.51 /MH	246,047	786,047
			BYPRODUCT HANDLING EQUIPMENT				**6,335,000**		**56,204**		**4,131,549**	**10,466,549**
		33.57.00	**SCALE**									
			SCALE - NEW TRUCK SCALES	BYPRODUCT HANDLING SYSTEM	2.00 EA	-	182,000	-	460	68.89 /MH	31,674	213,674
			SCALE				**182,000**		**460**		**31,674**	**213,674**
			MATERIAL HANDLING EQUIPMENT				**6,517,000**		**56,664**		**4,163,223**	**10,680,223**
	34.00.00		**HVAC**									
		34.37.00	**DUST COLLECTOR**									
			DUST COLLECTOR - INSTALLED COST		1.00 LS	113,100	-			64.51 /MH		113,100
			DUST COLLECTOR			**113,100**						**113,100**

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			HVAC			113,100						113,100
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	CONVEYOR PIPING	2,500.00 LF	-	-	248,000	3,966	77.80 /MH	308,517	556,517
			12 IN DIA, 3/8 IN STD	12" TIE IN PIPING TO BYPRODUCT SILO FROM THE EXISTING 50 TPH FLY ASH PRESSURE SYSTEM	1,500.00 LF	-	-	148,800	2,379	77.80 /MH	185,110	333,910
			CARBON STEEL, STRAIGHT RUN					396,800	6,345		493,628	890,428
			PIPING					396,800	6,345		493,628	890,428
			103 BYPRODUCT HANDLING SYSTEM			7,713,100	6,872,000	853,055	76,615		5,670,075	21,108,230
104			UNIT 1 OR 2 FLUE GAS SYSTEM									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG		138.00 EA	496,800	-	-		108.88 /MH		496,800
			PILING			496,800						496,800
			CIVIL WORK			496,800						496,800
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE		966.00 CY	-	-	222,180	7,772	60.03 /MH	466,578	688,758
			CONCRETE					222,180	7,772		466,578	688,758
			CONCRETE					222,180	7,772		466,578	688,758
	23.00.00		STEEL									
		23.15.00	DUCTWORK									
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES		867.40 TN	-	-	2,819,050	59,821	97.70 /MH	5,844,481	8,663,531
			DUCTWORK					2,819,050	59,821		5,844,481	8,663,531
		23.21.00	GIRDER									
			ROLLED SHAPE STEEL		1,308.00 TN	-	-	3,544,680	45,103	93.00 /MH	4,194,621	7,739,301
			GIRDER					3,544,680	45,103		4,194,621	7,739,301
			STEEL					6,363,730	104,924		10,039,102	16,402,832
	31.00.00		MECHANICAL EQUIPMENT									
		31.27.00	DAMPERS & ACCESSORIES									
			DAMPERS & ACCESSORIES		800.00 SF	-	240,000		1,471	97.70 /MH	143,743	383,743
			DAMPERS & ACCESSORIES				240,000		1,471		143,743	383,743
		31.33.00	EXPANSION JOINT									
			EXPANSION JOINTS		1,830.00 LF	-		457,500	5,259	97.70 /MH	513,767	971,267
			EXPANSION JOINT					457,500	5,259		513,767	971,267
			MECHANICAL EQUIPMENT				240,000	457,500	6,730		657,510	1,355,010
	36.00.00		INSULATION									
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE		168,220.00 SF	-	-	1,093,430	43,505	69.20 /MH	3,010,558	4,103,988
			DUCT					1,093,430	43,505		3,010,558	4,103,988
			INSULATION					1,093,430	43,505		3,010,558	4,103,988
			104 UNIT 1 OR 2 FLUE GAS SYSTEM			496,800	240,000	8,136,840	162,932		14,173,748	23,047,388
105			UNIT 1 OR 2 BOOSTER FANS									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON		40.00 EA	-	-	74,280	1,011	108.88 /MH	110,131	184,411
			CAISSON					74,280	1,011		110,131	184,411
			CIVIL WORK					74,280	1,011		110,131	184,411
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE		600.00 CY	-	-	138,000	4,828	60.03 /MH	289,800	427,800
			CONCRETE					138,000	4,828		289,800	427,800
			CONCRETE					138,000	4,828		289,800	427,800
	31.00.00		MECHANICAL EQUIPMENT									
		31.35.00	FANS & ACCESSORIES (EXCL HVAC)									
			BOOSTER FAN 1.8 MACFM, 4000 HP MOTOR		2.00 EA	-	5,400,000	-	10,345	68.89 /MH	712,655	6,112,655
			FANS & ACCESSORIES (EXCL HVAC)				5,400,000		10,345		712,655	6,112,655
			MECHANICAL EQUIPMENT				5,400,000		10,345		712,655	6,112,655
	36.00.00		INSULATION									
		36.15.00	EQUIPMENT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED ON GROUND		1,500.00 SF	-	-	315	11,207	69.20 /MH	775,517	775,832
			EQUIPMENT					315	11,207		775,517	775,832
			INSULATION					315	11,207		775,517	775,832
			105 UNIT 1 OR 2 BOOSTER FANS				**5,400,000**	**212,595**	**27,391**		**1,888,104**	**7,500,699**
106			**UNIT 1 OR 2 BAGHOUSE**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 60 FT LONG		326.00 EA	1,173,600	-	-		108.88 /MH		1,173,600
			PILING			1,173,600						1,173,600
			CIVIL WORK			1,173,600						1,173,600
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE		2,260.00 CY	-	-	519,800	18,184	60.03 /MH	1,091,580	1,611,380
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' COMPRESSOR BLDG	6.00 CY	-	-	1,380	48	60.03 /MH	2,898	4,278
			CONCRETE					521,180	18,232		1,094,478	1,615,658
			CONCRETE					521,180	18,232		1,094,478	1,615,658
	23.00.00		STEEL									
		23.25.00	ROLLED SHAPE									
			BUILDING MIX, GALVANIZED	UNIT 1 BAGHOUSE	560.00 TN	-	-	1,534,400	10,299	93.00 /MH	957,793	2,492,193
			ROLLED SHAPE					1,534,400	10,299		957,793	2,492,193
			STEEL					1,534,400	10,299		957,793	2,492,193
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING	8' X 10' COMPRESSOR BLDG	1.00 LT	-	-	20,000	115	93.00 /MH	10,690	30,690
			PRE-ENGINEERED BUILDING					20,000	115		10,690	30,690
		24.41.00	SIDING									
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	BAGHOUSE SKIRTS	68,112.00 SF	-	-	221,364	3,210	79.98 /MH	256,726	478,090
			SIDING					221,364	3,210		256,726	478,090
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			MISCELLANEOUS	BAGHOUSE SKIRTS MANDOORS	4.00 EA	-	-	2,000	37	51.46 /MH	1,893	3,893
			ARCHITECTURAL, MISCELLANEOUS					2,000	37		1,893	3,893
			ARCHITECTURAL					243,364	3,362		269,308	512,672
	31.00.00		MECHANICAL EQUIPMENT									
		31.57.00	PARTICULATE REMOVAL									
			BAGHOUSE SYSTEM - INCLUDES PENTHOUSE, BYPASS, DAMPERS, EXP. JOINTS, TUBESHEETS, BAGS, CAGES, CLEANING PIPING, VALVES, BLOWERS, ETC.		1.00 LS	-	20,000,000	-		/MH	13,000,000	33,000,000
			PARTICULATE REMOVAL				20,000,000				13,000,000	33,000,000
			MECHANICAL EQUIPMENT				20,000,000				13,000,000	33,000,000
	36.00.00		INSULATION									
		36.13.00	DUCT									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	BAGHOUSE INSUILATION TOP, SIDES AND HOPPERS	206,026.00 SF	-	-	1,339,169	53,283	69.20 /MH	3,687,155	5,026,324
			DUCT					1,339,169	53,283		3,687,155	5,026,324
			INSULATION					1,339,169	53,283		3,687,155	5,026,324
			106 UNIT 1 OR 2 BAGHOUSE			**1,173,600**	**20,000,000**	**3,638,113**	**85,175**		**19,008,734**	**43,820,447**
107			**EARTHWORK**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING	600,000.00 SF	-	-		1,379	182.87 /MH	252,234	252,234
			STRIP & STOCKPILE TOPSOIL - ONSITE	SITE GRADING	160,000.00 CY	-	-		21,149	182.87 /MH	3,867,595	3,867,595
			STRIP & STOCKPILE TOPSOIL						22,529		4,119,830	4,119,830
		21.17.00	EXCAVATION									
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS		20,917.00 CY	-	-		7,213	79.78 /MH	575,434	575,434
			EXCAVATION						7,213		575,434	575,434
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING	1.00 LT	-	-	110,000	2,299	72.57 /MH	166,828	276,828
			STORM DRAINAGE UTILITIES					110,000	2,299		166,828	276,828
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING	66,667.00 SY	-	-	710,004	2,299	97.70 /MH	224,599	934,602
			EROSION AND SEDIMENTATION CONTROL					710,004	2,299		224,599	934,602
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ROAD - ROAD UPGRADE	BYPRODUCT HAUL ROAD - EAST OF COAL PILE	10,000.00 LF	-	-	500,000	8,046	78.79 /MH	633,943	1,133,943
			BITUMINOUS ROAD - ELIMINATE CHICANE CURVES AT LOW PRESSURE SERVICE WATER PUMPS		1.00 LT	-	-	500,000		78.79 /MH		500,000
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ROADWORK 24' WIDE 4" ASPHALT	SITE GRADING	1,668.00 LF	-	-	201,828	2,013	78.79 /MH	158,612	360,440
			ROAD, PARKING AREA, & SURFACED AREA					1,201,828	10,059		792,555	1,994,383
			CIVIL WORK					2,021,832	44,398		5,879,245	7,901,077
			107 EARTHWORK					**2,021,832**	**44,398**		**5,879,245**	**7,901,077**
108			**LAYDOWN AREAS**									
	21.00.00		CIVIL WORK									
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	4.00 AC	-	-	312,000	3,678	79.78 /MH	293,444	605,444
			CIVIL WORK, MISCELLANEOUS					312,000	3,678		293,444	605,444
			CIVIL WORK					312,000	3,678		293,444	605,444
			108 LAYDOWN AREAS					**312,000**	**3,678**		**293,444**	**605,444**
109			**MECHANICAL MISCELLANEOUS**									
	31.00.00		MECHANICAL EQUIPMENT									
		31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS									
			MECHANICAL EQUIPMENT	INCLUDES PIPE RACK - ALLOWANCE	1.00 LS	2,600,000	-	-		68.89 /MH		2,600,000
			MECHANICAL EQUIPMENT, MISCELLANEOUS			2,600,000						2,600,000
			MECHANICAL EQUIPMENT			2,600,000						2,600,000
			109 MECHANICAL MISCELLANEOUS			**2,600,000**						**2,600,000**
110			**DEMOLITION/RELOCATION**									
	11.00.00		DEMOLITION									
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION AND RELOCATION	ALLOWANCE	1.00 LS	975,000	-			107.47 /MH		975,000
			DEMOLITION, MISCELLANEOUS			975,000						975,000
			DEMOLITION			975,000						975,000
			110 DEMOLITION/RELOCATION			**975,000**						**975,000**
111			**ACI RELOCATION**									
	22.00.00		CONCRETE									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ACI PORT STAIRTOWER FDNS	30.00 CY	-	-	6,900	241	60.03 /MH	14,490	21,390
			CONCRETE					6,900	241		14,490	21,390
			CONCRETE					6,900	241		14,490	21,390
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	ACI PORT STAIR TOWERS AND PLATFORMS	364.00 SF	-	-	5,460	42	66.40 /MH	2,778	8,238
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	ACI PORT STAIR TOWERS AND PLATFORMS	218.00 LF	-	-	11,554	45	66.40 /MH	2,995	14,549
			STAIR SYSTEM -	ACI PORT STAIR TOWERS AND PLATFORMS	448.00 SF	-	-	40,768	592	66.40 /MH	39,321	80,089
			GALLERY					57,782	679		45,094	102,876
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	ACI PIPE RACK OVER ROADWAY, 35LF X 23 WIDE X 20' HIGH	1.26 TN	-	-	3,415	25	93.00 /MH	2,290	5,704
			GIRDER					3,415	25		2,290	5,704
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	ACI PORT STAIRTOWER FRAMING - 1 TOWER	2.20 TN	-	-	7,876	56	93.00 /MH	5,174	13,050
			ROLLED SHAPE					7,876	56		5,174	13,050
			STEEL					69,073	759		52,558	121,630
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			MOTORIZED HOIST - 1 TON	RELOCATED FROM PRESENT PORT LOCATIOIN	1.00 EA	-	-	-	69	68.89 /MH	4,751	4,751
			CRANES & HOISTS						69		4,751	4,751
		31.51.00	MERCURY REMOVAL EQUIPMENT									
			ACTIVATED CARBON INJECTION (ACI) - LANCE RELOCATIONS	RELOCATED FROM PRESENT PORT LOCATIOIN (16 PER UNIT)	16.00 EA	-	-	-	184	68.89 /MH	12,669	12,669
			ACTIVATED CARBON INJECTION (ACI) - 40 HP BLOWERS	NEW BLOWERS (2 PER UNIT)	2.00 EA	-	-	40,000	92	68.89 /MH	6,335	46,335
			ACTIVATED CARBON INJECTION (ACI) - REMOVE EXISTING 20 HP BLOWERS	REMOVE EXISTING	1.00 EA	-	-	-	11	68.89 /MH	792	792
			MERCURY REMOVAL EQUIPMENT					40,000	287		19,796	59,796
			MECHANICAL EQUIPMENT					40,000	356		24,547	64,547
	35.00.00		PIPING									
		35.13.25	FRP, ABOVE GROUND, PROCESS AREA									
			1.5 IN DIA, TAPER	INJECTION PORTS	6.00 LF	-	-	176	3	77.80 /MH	220	396
			2 IN DIA, TAPER	INJECTION PORTS	8.00 LF	-	-	210	5	77.80 /MH	351	561
			3 IN DIA, TAPER	INJECTION PORTS	20.00 LF	-	-	516	15	77.80 /MH	1,198	1,714
			FRP, ABOVE GROUND, PROCESS AREA					903	23		1,769	2,672
		35.14.25	FRP, STRAIGHT RUN									
			4 IN DIA, TAPER	NEW ACI PIPING	300.00 LF	-	-	6,330	200	77.80 /MH	15,560	21,890
			FRP, STRAIGHT RUN					6,330	200		15,560	21,890
		35.36.00	PIPE SUPPORTS, RACK									
			U-BOLT FOR 4 IN PIPE	ACI PIPE	13.50 EA	-	-	41	31	77.80 /MH	2,414	2,455
			SUPPORT SLEEPERS	ACI PIPE	8.50 EA	-	-	2,975	39	77.80 /MH	3,040	6,015
			SUPPORT FOR 4 IN DIA PIPE - USER DEFINED		1.00 EA	-	-	153	9	77.80 /MH	715	868
			SUPPORT FOR 3 IN DIA PIPE - USER DEFINED		2.00 EA	-	-	288	16	77.80 /MH	1,252	1,540
			PIPE SUPPORTS, RACK					3,457	95		7,422	10,879
		35.45.00	VALVES									
			VALVE - 4" 150 LB CS GATE, FLANGED	ACI AUTO MATIC ISOLATION VALVES (RELOCATE 4 PER UNIT)	4.00 EA	-	-	80	33	77.80 /MH	2,575	2,655
			VALVES					80	33		2,575	2,655
			PIPING					10,769	351		27,327	38,096
	41.00.00		ELECTRICAL EQUIPMENT									
		41.46.00	MOTOR CONTROL CENTER (MCC), COMPONENT									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		41.46.00	MOTOR CONTROL CENTER (MCC), COMPONENT									
			FVN STARTER - #4,	NEW BLOWERS	2.00 EA	-	-	9,800	37	64.04 /MH	2,355	12,155
			MOTOR CONTROL CENTER (MCC), COMPONENT					9,800	37		2,355	12,155
			ELECTRICAL EQUIPMENT					9,800	37		2,355	12,155
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.15.23	CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY									
			1-1/2 IN DIA, 3 FT LONG INCLUDING (2) CONNECTORS	NEW BLOWERS	2.00 EA	-	-	172	3	62.27 /MH	179	351
			CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY					172	3		179	351
		42.15.37	CONDUIT, RGS									
			3/4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	HOIST	225.00 LF	-	-	659	50	62.27 /MH	3,124	3,783
			1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	NEW BLOWERS	200.00 LF	-	-	1,344	65	62.27 /MH	4,065	5,409
			CONDUIT, RGS					2,003	115		7,190	9,193
			RACEWAY, CABLE TRAY & CONDUIT					2,175	118		7,369	9,544
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC	ACI RELOCATION	300.00 LF	-	-	960	28	82.56 /MH	2,278	3,238
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					960	28		2,278	3,238
		43.20.00	600V CABLE & TERMINATION									
			600V #8 3/C CU EPR TS-CPE	HOIST	250.00 LF	-	-	1,640	7	82.56 /MH	593	2,233
			600V #4/0 3/C W/G CU EPR TS-CPE	NEW BLOWERS	225.00 LF	-	-	5,364	36	82.56 /MH	2,989	8,353
			TERMINATION - COMPRESSION LUG, #8, 2 HOLE, COPPER	HOIST	6.00 EA	-	-	39	2	82.56 /MH	171	210
			TERMINATION - COMPRESSION LUG, #4, 2 HOLE, COPPER	NEW BLOWERS	6.00 EA	-	-	56	3	82.56 /MH	285	340
			600V CABLE & TERMINATION					7,099	49		4,038	11,136
			CABLE					8,059	76		6,315	14,374
	44.00.00		CONTROL & INSTRUMENTATION									
		44.21.00	INSTRUMENT									
			ACCOUSTIC MONITOR	RELOCATE TO NEW INJECTION LANCES	3.00 EA	-	-		14	65.15 /MH	899	899
			INSTRUMENT						14		899	899
			CONTROL & INSTRUMENTATION						14		899	899
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			COMPUTATIONAL FLUID DYNAMIC ANALYSIS (CFD)	ACI SYSTEM	1.00 LS	100,000	-			/MH		100,000
			CONSULTANT, THIRD PARTY			100,000						100,000
			PROJECT INDIRECT			100,000						100,000
			111 ACI RELOCATION			**100,000**		**146,775**	**1,954**		**135,859**	**382,635**
112			**ELECTRICAL**									
	41.00.00		ELECTRICAL EQUIPMENT									
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS	ALLOWANCE	1.00 LS	16,250,000	-			64.04 /MH		16,250,000
			ELECTRICAL EQUIPMENT, MISCELLANEOUS			16,250,000						16,250,000
			ELECTRICAL EQUIPMENT			16,250,000						16,250,000
			112 ELECTRICAL			**16,250,000**						**16,250,000**
113			**INSTRUMENTATION**									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.99.00	CONTROL & INSTRUMENTATION, ALLOWANCE									
			CONTROL & INSTRUMENTATION	ALLOWANCE	1.00 LS	2,210,000	-			65.15 /MH		2,210,000
			CONTROL & INSTRUMENTATION, ALLOWANCE			2,210,000						2,210,000
			CONTROL & INSTRUMENTATION			2,210,000						2,210,000
			113 INSTRUMENTATION			**2,210,000**						**2,210,000**

Table B-8. Baseline Visibility Impairment Attributable to Unit 1 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.912	1.505	38	74.33	25.34	0.17	0.15
2002	2.048	1.306	29	61.53	34.59	0.83	3.04
2003	4.020	1.053	32	47.92	50.35	0.35	1.39
Upper Buffalo							
2001	2.089	1.051	30	68.58	31.17	0.26	0.00
2002	1.438	0.742	15	79.11	20.19	0.37	0.32
2003	1.773	1.033	24	79.79	19.92	0.28	0.00
Hercules Glades							
2001	1.643	0.925	24	90.21	9.56	0.23	0.00
2002	1.184	0.567	10	74.20	25.45	0.25	0.10
2003	1.977	0.704	15	86.02	13.73	0.25	0.00
Mingo							
2001	1.538	0.802	16	51.46	48.03	0.39	0.12
2002	0.898	0.708	21	54.87	44.82	0.31	0.01
2003	1.003	0.666	14	57.31	41.18	0.41	1.11

Table B-9. Baseline Visibility Impairment Attributable to Unit 2 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.994	1.533	39	36.23	60.75	0.74	2.28
2002	2.098	1.322	29	59.43	36.53	0.82	3.22
2003	4.084	1.059	32	96.37	3.38	0.24	0.01
Upper Buffalo							
2001	2.066	1.059	30	66.54	33.21	0.26	0.00
2002	1.447	0.739	16	77.57	21.71	0.37	0.35
2003	1.791	1.030	25	78.24	21.46	0.28	0.00
Hercules Glades							
2001	1.665	0.912	25	89.39	10.38	0.23	0.00
2002	1.185	0.568	11	72.38	27.26	0.25	0.11
2003	1.947	0.720	16	40.35	58.44	0.40	0.82
Mingo							
2001	1.580	0.819	15	81.62	17.93	0.33	0.12
2002	0.886	0.719	20	58.93	40.66	0.19	0.22
2003	0.999	0.678	14	55.08	43.36	0.40	1.17

APPENDIX C. REFINED PM SPECIATION CALCULATIONS

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - 2009-2013 Baseline

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**40.38**	**lb/hr**	(PMC)
Fine Soil	**31.11**	**lb/hr**	(PMF)
Fine EC	**1.20**	**lb/hr**	(EC)
CPM OR	**9.31**	**lb/hr**	(SOA)
CMP IOR	**5.11**	**lb/hr**	(SO_4)

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	**Page Reference**
TSAR = Total sulfuric acid release	
= {[(EM$_{Comb}$ + EM$_{SCR}$ + EM$_{FGC_beforeAPH}$) - (NH3$_{SCR}$ + NH3$_{FGC_beforeAPH}$)] * F2$_{APH}$ + (EM$_{FGC_afterAPH}$ - NH3$_{FGC_afterAPH}$)} * F2$_x$	4-11 (Eqn 4-10)
= 44,739.30 lb/year	
where:	
EM$_{Comb}$ = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 172,605.31 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 29,661.00 tons/yr (max day during 2014-2016)	Entergy CAMD data
EM$_{SCR}$ = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM$_{FGC}$ = H_2SO_4 manufactured from flue gas conditioning	
= K$_e$ * B * f$_e$ * I$_s$ * F3$_{FGC}$ EM$_{FGC_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
EM$_{FGC_afterAPH}$ = 0.00 lb/year	
where K$_e$ = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 82.12 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f$_e$ = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I$_s$ = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
F3$_{FGC}$ = Technology impact factor	4-9 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
NH3$_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
F2$_{APH}$ = Technology impact factor for APH; only apply if [(EM$_{Comb}$ + EM$_{SCR}$ + EM$_{FGC_beforeAPH}$) - (NH3$_{SCR}$ + NH3$_{FGC_beforeAPH}$)] is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
NH3$_{FGC}$ = Ammonia produced from FGC	4-14
= K$_e$ * B * f$_e$ * I$_{NH3}$ NH3$_{FGC_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
NH3$_{FGC_afterAPH}$ = 0.00 lb/year	
where K$_e$ = *3,799*	*see above*
B = *82.12*	*see above*
f$_e$ = *0* unitless	No Ammonia FGC
I$_{NH3}$ = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
F2$_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - 2009-2013 Baseline

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions (**Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions (**Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions (**Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**40.38 lb/hr**	(PMC)
Fine Soil	**31.11 lb/hr**	(PMF)
Fine EC	**1.20 lb/hr**	(EC)
CPM OR	**9.31 lb/hr**	(SOA)
CMP IOR	**4.99 lb/hr**	(SO_4)

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012				Page Reference
TSAR		=	Total sulfuric acid release	
		=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
		=	43,750.51 lb/year	
where:				
EM_{Comb}	=		H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
	=		K * F1 * E2	
	=		168,790.55 lb/year	
where	K	=	Units conversion factor	4-1
		=	3,063 lb H_2SO_4/ton SO_2	4-1
	F1	=	Fuel Impact Factor	4-1
		=	0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
	E2	=	SO_2 emission rate	4-1
		=	29,005.46 tons/yr (max day during 2014-2016)	Entergy CAMD data
EM_{SCR}	=		H_2SO_4 manufactured from SCR/SNCR	4-7
	=		0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC}	=		H_2SO_4 manufactured from flue gas conditioning	
	=		$K_e * B * f_e * I_s * F3_{FGC}$ — $EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
			$EM_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e	=	Conversion factor	4-9
		=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
	B	=	Coal burn	4-9
		=	77.87 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
	f_e	=	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
		=	0 *unitless*	No SO_3 FGC
	I_s	=	SO_3 injection rate	4-9
		=	N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
	$F3_{FGC}$	=	Technology impact factor	4-9 — 5 ppmv if after APH
		=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=		Ammonia slip produced from SCR/SNCR	4-13
	=		0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$	=		Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
	=		0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=		Ammonia produced from FGC	4-14
	=		$K_e * B * f_e * I_{NH3}$ — $NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
			$NH3_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e	=	*3,799*	*see above*
	B	=	*77.87*	*see above*
	f_e	=	*0* unitless	No Ammonia FGC
	I_{NH3}	=	NH_3 injection for dual FGC	4-14
		=	N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$	=		Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
	=		0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - Fuel switch to Low Sulfur Coal

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**40.38**	**lb/hr**	(PMC)
Fine Soil	**31.11**	**lb/hr**	(PMF)
Fine EC	**1.20**	**lb/hr**	(EC)
CPM OR	**9.31**	**lb/hr**	(SOA)
CMP IOR	**4.05**	**lb/hr**	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012					Page Reference		
TSAR	= Total sulfuric acid release						
	= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$				4-11 (Eqn 4-10)		
	=	35,477.40 lb/year					
where:							
EM_{Comb}	=	H_2SO_4 manufactured from combustion			4-1 (Eqn 4-1)		
	=	K * F1 * E2					
	=	136,872.70 lb/year					
where	K =	Units conversion factor			4-1		
	=	3,063 lb H_2SO_4/ton SO_2			4-1		
	F1 =	Fuel Impact Factor			4-1		
	=	0.0019 *unitless*			4-6 (Table 4-1 for Subbituminous/PRB Coal)		
	E2 =	SO_2 emission rate			4-1		
	=	23,520.60 tons/yr (max day during 2014-2016)			Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input		
EM_{SCR}	=	H_2SO_4 manufactured from SCR/SNCR			4-7		
	=	0 lb/year			SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)		
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning					
	=	$K_e * B * f_e * I_s * F3_{FGC}$	$EM_{FGC\_beforeAPH}$ =	0.00 lb/year	4-9 (Eqn 4-7)		
			$EM_{FGC\_afterAPH}$ =	0.00 lb/year			
where	K_e =	Conversion factor			4-9		
	=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)			4-10 (Text Box B)		
	B =	Coal burn			4-9		
	=	82.12 TBtu/yr (max day during 2014-2016)			Entergy CAMD data		
	f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates			4-9		
	=	0 *unitless*			No SO_3 FGC		
	I_s =	SO_3 injection rate			4-9		
	=	N/A ppmv at 6% O_2, wet			default value =	7	ppmv if before APH
	$F3_{FGC}$ =	Technology impact factor			4-9	5	ppmv if after APH
	=	0.17 *unitless*			4-9 (for PRB coal)		
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR			4-13		
	=	0 lb/year			SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)		
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive			4-12		
	=	0.36 for air heater			4-18 (Table 4-3 for PRB)		
$NH3_{FGC}$	=	Ammonia produced from FGC			4-14		
	=	$K_e * B * f_e * I_{NH3}$	$NH3_{FGC\_beforeAPH}$ =	0.00 lb/year	4-14 (Eqn 4-14)		
			$NH3_{FGC\_afterAPH}$ =	0.00 lb/year			
where	K_e =	*3,799*			*see above*		
	B =	*82.12*			*see above*		
	f_e =	*0* unitless			No Ammonia FGC		
	I_{NH3} =	NH_3 injection for dual FGC			4-14		
	=	N/A ppmv at 6% O_2, wet			default value =	3	ppmv
$F2_X$	=	Technology impact factors for processes downstream of the APH (product of all that apply)			4-12		
	=	0.72 for cold-side ESP			4-20 (Table 4-4 for PRB)		

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - Fuel switch to Low Sulfur Coal

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using only ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0256	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.010**	**0.008**	SO4	3*f(RH)	**0.002**	SOA	4

	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.440	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.172	0.137	SO4	3*f(RH)	0.034	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	60.9%	33.9%	0.6	27.1%	26.1%	1	1.0%	10	39.1%	31.2%	SO4	3*f(RH)	7.8%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	72.7	40.4	0.6	32.3	31.1	1	1.2	10	46.6	37.3	SO4	3	9.3	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**40.38 lb/hr**	(PMC)
Fine Soil	**31.11 lb/hr**	(PMF)
Fine EC	**1.20 lb/hr**	(EC)
CPM OR	**9.31 lb/hr**	(SOA)
CMP IOR	**4.05 lb/hr**	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012				**Page Reference**
TSAR	= Total sulfuric acid release			
	= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$			4-11 (Eqn 4-10)
	= 35,477.40 lb/year			
where:				
EM_{Comb} =	H_2SO_4 manufactured from combustion			4-1 (Eqn 4-1)
=	K * F1 * E2			
=	136,872.70 lb/year			
where K =	Units conversion factor			4-1
=	3,063 lb H_2SO_4/ton SO_2			4-1
F1 =	Fuel Impact Factor			4-1
=	0.0019 *unitless*			4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 =	SO_2 emission rate			4-1
=	23,520.60 tons/yr (max day during 2014-2016)			Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} =	H_2SO_4 manufactured from SCR/SNCR			4-7
=	0 lb/year			SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} =	H_2SO_4 manufactured from flue gas conditioning			
=	$K_e * B * f_e * I_s * F3_{FGC}$	$EM_{FGC\_beforeAPH}$ =	0.00 lb/year	4-9 (Eqn 4-7)
		$EM_{FGC\_afterAPH}$ =	0.00 lb/year	
where K_e =	Conversion factor			4-9
=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)			4-10 (Text Box B)
B =	Coal burn			4-9
=	77.87 TBtu/yr (max day during 2014-2016)			Entergy CAMD data
f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates			4-9
=	0 *unitless*			No SO_3 FGC
I_s =	SO_3 injection rate			4-9
=	N/A ppmv at 6% O_2, wet			default value = 7 ppmv if before APH
$F3_{FGC}$ =	Technology impact factor			4-9 5 ppmv if after APH
=	0.17 *unitless*			4-9 (for PRB coal)
$NH3_{SCR}$ =	Ammonia slip produced from SCR/SNCR			4-13
=	0 lb/year			SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ =	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive			4-12
=	0.36 for air heater			4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ =	Ammonia produced from FGC			4-14
=	$K_e * B * f_e * I_{NH3}$	$NH3_{FGC\_beforeAPH}$ =	0.00 lb/year	4-14 (Eqn 4-14)
		$NH3_{FGC\_afterAPH}$ =	0.00 lb/year	
where K_e =	*3,799*			*see above*
B =	*77.87*			*see above*
f_e =	*0* unitless			No Ammonia FGC
I_{NH3} =	NH_3 injection for dual FGC			4-14
=	N/A ppmv at 6% O_2, wet			default value = 3 ppmv
$F2_X$ =	Technology impact factors for processes downstream of the APH (product of all that apply)			4-12
=	0.72 for cold-side ESP			4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - DSI with ESP

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD + ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)

Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0356	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)

Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.612	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

Controlled PM10 Emissions

Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	43.8%	24.4%	0.6	19.5%	18.8%	1	0.7%	10	56.2%	44.9%	SO4	3*f(RH)	11.2%	SOA	4

If you are given Total PM10 emissions in lb/hr:

Controlled PM10 Emissions **(Bold** Value is **Input** by user.)

Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	52.3	29.0	0.6	23.2	22.4	1	0.9	10	67.0	53.6	SO4	3	13.4	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**29.04 lb/hr**	(PMC)
Fine Soil	**22.37 lb/hr**	(PMF)
Fine EC	**0.86 lb/hr**	(EC)
CPM OR	**13.40 lb/hr**	(SOA)
CMP IOR	**0.47 lb/hr**	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012					Page Reference	
TSAR	=	Total sulfuric acid release				
	=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$			4-11 (Eqn 4-10)	
	=	20,695.15 lb/year				
where:						
EM_{Comb}	=	H_2SO_4 manufactured from combustion			4-1 (Eqn 4-1)	
	=	K * F1 * E2				
	=	79,842.41 lb/year				
where K	=	Units conversion factor			4-1	
	=	3,063 lb H_2SO_4/ton SO_2			4-1	
F1	=	Fuel Impact Factor			4-1	
	=	0.0019 *unitless*			4-6 (Table 4-1 for Subbituminous/PRB Coal)	
E2	=	SO_2 emission rate			4-1	
	=	13,720.35 tons/yr (max day during 2014-2016)			Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input	
EM_{SCR}	=	H_2SO_4 manufactured from SCR/SNCR			4-7	
	=	0 lb/year			SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)	
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning				
	=	$K_e * B * f_e * I_s * F3_{FGC}$	$EM_{FGC\_beforeAPH}$ = 0.00	lb/year	4-9 (Eqn 4-7)	
			$EM_{FGC\_afterAPH}$ = 0.00	lb/year		
where K_e	=	Conversion factor			4-9	
	=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)			4-10 (Text Box B)	
B	=	Coal burn			4-9	
	=	82.12 TBtu/yr (max day during 2014-2016)			Entergy CAMD data	
f_e	=	Operating factor of FGC system - the fraction of coal burn when the FGC operates			4-9	
	=	0 *unitless*			No SO_3 FGC	
I_s	=	SO_3 injection rate			4-9	
	=	N/A ppmv at 6% O_2, wet			default value =	7 ppmv if before APH
$F3_{FGC}$	=	Technology impact factor			4-9	5 ppmv if after APH
	=	0.17 *unitless*			4-9 (for PRB coal)	
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR			4-13	
	=	0 lb/year			SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)	
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive			4-12	
	=	0.36 for air heater			4-18 (Table 4-3 for PRB)	
$NH3_{FGC}$	=	Ammonia produced from FGC			4-14	
	=	$K_e * B * f_e * I_{NH3}$	$NH3_{FGC\_beforeAPH}$ = 0.00	lb/year	4-14 (Eqn 4-14)	
			$NH3_{FGC\_afterAPH}$ = 0.00	lb/year		
where K_e	=	*3,799*			*see above*	
B	=	*82.12*			*see above*	
f_e	=	*0* unitless			No Ammonia FGC	
I_{NH3}	=	NH_3 injection for dual FGC			4-14	
	=	N/A ppmv at 6% O_2, wet			default value =	3 ppmv
$F2_X$	=	Technology impact factors for processes downstream of the APH (product of all that apply)			4-12	
	=	0.72 for cold-side ESP			4-20 (Table 4-4 for PRB)	
$TSAR_{ALKINJ}$	=	$(TSAR_{Comb+SCR+FGC}) * F3_{ALKINJ}$			3-9 (Eqn 3-10, DSI)	
$TSAR_{Comb+SCR+FGC}$	=	20,695.15 lb/year				
$F3_{ALKINJ}$	=	0.2 Default of 0.2 indicates 80% removal of H2SO4			3-9	
	=	4,139.03 lb/year				

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - DSI with ESP

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD + ESP for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0356	0.0156	0.0087	0.6	0.0069	0.0067	1	0.0003	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.612	**0.268**	0.149	0.6	**0.119**	0.115	1	0.004	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	43.8%	24.4%	0.6	19.5%	18.8%	1	0.7%	10	56.2%	44.9%	SO4	3*f(RH)	11.2%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	52.3	29.0	0.6	23.2	22.4	1	0.9	10	67.0	53.6	SO4	3	13.4	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**29.04 lb/hr**	(PMC)
Fine Soil	**22.37 lb/hr**	(PMF)
Fine EC	**0.86 lb/hr**	(EC)
CPM OR	**13.40 lb/hr**	(SOA)
CMP IOR	**0.47 lb/hr**	(SO_4)

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012			Page Reference
TSAR	=	Total sulfuric acid release	
	=	{[(EM_{Comb} + EM_{SCR} + $EM_{FGC\_beforeAPH}$) - ($NH3_{SCR}$ + $NH3_{FGC\_beforeAPH}$)] * $F2_{APH}$ + ($EM_{FGC\_afterAPH}$ - $NH3_{FGC\_afterAPH}$)} * $F2_x$	4-11 (Eqn 4-10)
	=	20,695.15 lb/year	
where:			
EM_{Comb}	=	H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
	=	K * F1 * E2	
	=	79,842.41 lb/year	
where	K =	Units conversion factor	4-1
	=	3,063 lb H_2SO_4/ton SO_2	4-1
	F1 =	Fuel Impact Factor	4-1
	=	0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
	E2 =	SO_2 emission rate	4-1
	=	13,720.35 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR}	=	H_2SO_4 manufactured from SCR/SNCR	4-7
	=	0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning	
	=	K_e * B * f_e * I_s * $F3_{FGC}$ — $EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
		$EM_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e =	Conversion factor	4-9
	=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
	B =	Coal burn	4-9
	=	77.87 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
	f_e =	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
	=	0 *unitless*	No SO_3 FGC
	I_s =	SO_3 injection rate	4-9
	=	N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
	$F3_{FGC}$ =	Technology impact factor	4-9 — 5 ppmv if after APH
	=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR	4-13
	=	0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$	=	Technology impact factor for APH; only apply if [(EM_{Comb} + EM_{SCR} + $EM_{FGC\_beforeAPH}$) - ($NH3_{SCR}$ + $NH3_{FGC\_beforeAPH}$)] is positive	4-12
	=	0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC	4-14
	=	K_e * B * f_e * I_{NH3} — $NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
		$NH3_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e =	*3,799*	*see above*
	B =	*77.87*	*see above*
	f_e =	*0* unitless	No Ammonia FGC
	I_{NH3} =	NH_3 injection for dual FGC	4-14
	=	N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$	=	Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
	=	0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
$TSAR_{ALKINJ}$	=	($TSAR_{Comb+SCR+FGC}$) * $F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
	$TSAR_{Comb+SCR+FGC}$ =	20,695.15 lb/year	
	$F3_{ALKINJ}$ =	0.2 Default of 0.2 indicates 80% removal of H2SO4	3-9
	=	4,139.03 lb/year	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - DSI with ESP and Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)																
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**13.37 lb/hr**	(PMC)
Fine Soil	**12.87 lb/hr**	(PMF)
Fine EC	**0.49 lb/hr**	(EC)
CPM OR	**18.50 lb/hr**	(SOA)
CMP IOR	**0.02 lb/hr**	(SO_4)

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012				Page Reference
TSAR		=	Total sulfuric acid release	
		=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
		=	886.94 lb/year	
where:				
EM_{Comb}	=		H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
	=		K * F1 * E2	
	=		34,218.18 lb/year	
where	K	=	Units conversion factor	4-1
		=	3,063 lb H_2SO_4/ton SO_2	4-1
	F1	=	Fuel Impact Factor	4-1
		=	0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
	E2	=	SO_2 emission rate	4-1
		=	5,880.15 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR}	=		H_2SO_4 manufactured from SCR/SNCR	4-7
	=		0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC}	=		H_2SO_4 manufactured from flue gas conditioning	
	=		$K_e * B * f_e * I_s * F3_{FGC}$ $EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
			$EM_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e	=	Conversion factor	4-9
		=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
	B	=	Coal burn	4-9
		=	82.12 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
	f_e	=	Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
		=	0 *unitless*	No SO_3 FGC
	I_s	=	SO_3 injection rate	4-9
		=	N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
	$F3_{FGC}$	=	Technology impact factor	4-9 5 ppmv if after APH
		=	0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$	=		Ammonia slip produced from SCR/SNCR	4-13
	=		0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$	=		Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
	=		0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=		Ammonia produced from FGC	4-14
	=		$K_e * B * f_e * I_{NH3}$ $NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
			$NH3_{FGC\_afterAPH}$ = 0.00 lb/year	
where	K_e	=	*3,799*	*see above*
	B	=	*82.12*	*see above*
	f_e	=	*0 unitless*	No Ammonia FGC
	I_{NH3}	=	NH_3 injection for dual FGC	4-14
		=	N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$	=		Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
	=		0.72 for cold-side ESP	4-20 (Table 4-4 for PRB)
	=		0.1 for baghouse in addition to ESP (per S&L report for Enhanced DSI)	4-20 (Table 4-4)
	=		0.072 product of all factors	
$TSAR_{ALKINJ}$	=		$(TSAR_{Comb+SCR+FGC}) * F3_{ALKINJ}$	3-9 (Eqn 3-10, DSI)
	$TSAR_{Comb+SCR+FGC}$	=	886.94 lb/year	
	$F3_{ALKINJ}$	=	0.2 Default of 0.2 indicates 80% removal of H2SO4	3-9
	=		177.39 lb/year	

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - DSI with ESP and Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)															
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**13.37 lb/hr**	(PMC)
Fine Soil	**12.87 lb/hr**	(PMF)
Fine EC	**0.49 lb/hr**	(EC)
CPM OR	**18.50 lb/hr**	(SOA)
CMP IOR	**0.02 lb/hr**	(SO_4)

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012				Page Reference
TSAR	=	Total sulfuric acid release		
	=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$		4-11 (Eqn 4-10)
	=	886.94 lb/year		
where:				
EM_{Comb}	=	H_2SO_4 manufactured from combustion		4-1 (Eqn 4-1)
	=	K * F1 * E2		
	=	34,218.18 lb/year		
where K	=	Units conversion factor		4-1
	=	3,063 lb H_2SO_4/ton SO_2		4-1
F1	=	Fuel Impact Factor		4-1
	=	0.0019 *unitless*		4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2	=	SO_2 emission rate		4-1
	=	5,880.15 tons/yr (max day during 2014-2016)		Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR}	=	H_2SO_4 manufactured from SCR/SNCR		4-7
	=	0 lb/year		SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC}	=	H_2SO_4 manufactured from flue gas conditioning		
	=	$K_e * B * f_e * I_s * F3_{FGC}$	$EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
			$EM_{FGC\_afterAPH}$ = 0.00 lb/year	
where K_e	=	Conversion factor		4-9
	=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)		4-10 (Text Box B)
B	=	Coal burn		4-9
	=	77.87 TBtu/yr (max day during 2014-2016)		Entergy CAMD data
f_e	=	Operating factor of FGC system - the fraction of coal burn when the FGC operates		4-9
	=	0 *unitless*		No SO_3 FGC
I_s	=	SO_3 injection rate		4-9
	=	N/A ppmv at 6% O_2, wet		default value = 7 ppmv if before APH
$F3_{FGC}$	=	Technology impact factor		4-9 5 ppmv if after APH
	=	0.17 *unitless*		4-9 (for PRB coal)
$NH3_{SCR}$	=	Ammonia slip produced from SCR/SNCR		4-13
	=	0 lb/year		SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$	=	Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive		4-12
	=	0.36 for air heater		4-18 (Table 4-3 for PRB)
$NH3_{FGC}$	=	Ammonia produced from FGC		4-14
	=	$K_e * B * f_e * I_{NH3}$	$NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
			$NH3_{FGC\_afterAPH}$ = 0.00 lb/year	
where K_e	=	*3,799*		*see above*
B	=	*77.87*		*see above*
f_e	=	*0 unitless*		No Ammonia FGC
I_{NH3}	=	NH_3 injection for dual FGC		4-14
	=	N/A ppmv at 6% O_2, wet		default value = 3 ppmv
$F2_X$	=	Technology impact factors for processes downstream of the APH (product of all that apply)		4-12
	=	0.72 for cold-side ESP		4-20 (Table 4-4 for PRB)
	=	0.1 for baghouse in addition to ESP (per S&L report for Enhanced DSI)		4-20 (Table 4-4)
	=	0.072 product of all factors		
$TSAR_{ALKINJ}$	=	$(TSAR_{Comb+SCR+FGC}) * F3_{ALKINJ}$		3-9 (Eqn 3-10, DSI)
$TSAR_{Comb+SCR+FGC}$	=	886.94 lb/year		
$F3_{ALKINJ}$	=	0.2 Default of 0.2 indicates 80% removal of H2SO4		3-9
	=	177.39 lb/year		

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm)
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
"Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012.
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler - DFGD with Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)																
Boiler Type	Total PM10 (lb/mmBtu)	Filterable (lb/mmBtu)	Coarse (lb/mmBtu)	Ext. Coef.	Fine (lb/mmBtu)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/mmBtu)	Ext. Coef.	Condensible (lb/mmBtu)	CPM IOR (lb/mmBtu)	Particle Type	Particle Ext.Coef.	CPM OR (lb/mmBtu)	Particle Type	Particle Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler Type	Total PM10 (lb/ton)	Filterable (lb/ton)	Coarse (lb/ton)	Ext. Coef.	Fine (lb/ton)	Fine Soil (lb/ton)	Ext. Coef.	Fine EC (lb/ton)	Ext. Coef.	Condensible (lb/ton)	CPM IOR (lb/ton)	Particle Type	Particle Ext.Coef.	CPM OR (lb/ton)	Particle Type	Particle Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler Type	Total PM10 (% of Total)	Filterable (% of Total)	Coarse (% of Total)	Ext. Coef.	Fine (% of Total)	Fine Soil (% of Total)	Ext. Coef.	Fine EC (% of Total)	Ext. Coef.	Condensible (% of Total)	CPM IOR (% of Total)	Particle Type	Particle Ext.Coef.	CPM OR (% of Total)	Particle Type	Particle Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler Type	Total PM10 (lb/hr)	Filterable (lb/hr)	Coarse (lb/hr)	Ext. Coef.	Fine (lb/hr)	Fine Soil (lb/hr)	Ext. Coef.	Fine EC (lb/hr)	Ext. Coef.	Condensible (lb/hr)	CPM IOR (lb/hr)	Particle Type	Particle Ext.Coef.	CPM OR (lb/hr)	Particle Type	Particle Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**13.37 lb/hr**	(PMC)
Fine Soil	**12.87 lb/hr**	(PMF)
Fine EC	**0.49 lb/hr**	(EC)
CPM OR	**18.50 lb/hr**	(SOA)
CMP IOR	**0.01 lb/hr**	(SO_4)

PM Speciation Calculations

Entergy White Bluff
Unit 1 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012	**Page Reference**
TSAR = Total sulfuric acid release	
= $\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$	4-11 (Eqn 4-10)
= 49.27 lb/year	
where:	
EM_{Comb} = H_2SO_4 manufactured from combustion	4-1 (Eqn 4-1)
= K * F1 * E2	
= 13,687.27 lb/year	
where K = Units conversion factor	4-1
= 3,063 lb H_2SO_4/ton SO_2	4-1
F1 = Fuel Impact Factor	4-1
= 0.0019 *unitless*	4-6 (Table 4-1 for Subbituminous/PRB Coal)
E2 = SO_2 emission rate	4-1
= 2,352.06 tons/yr (max day during 2014-2016)	Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input
EM_{SCR} = H_2SO_4 manufactured from SCR/SNCR	4-7
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
EM_{FGC} = H_2SO_4 manufactured from flue gas conditioning	
= $K_e * B * f_e * I_s * F3_{FGC}$ — $EM_{FGC\_beforeAPH}$ = 0.00 lb/year	4-9 (Eqn 4-7)
$EM_{FGC\_afterAPH}$ = 0.00 lb/year	
where K_e = Conversion factor	4-9
= 3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)	4-10 (Text Box B)
B = Coal burn	4-9
= 82.12 TBtu/yr (max day during 2014-2016)	Entergy CAMD data
f_e = Operating factor of FGC system - the fraction of coal burn when the FGC operates	4-9
= 0 *unitless*	No SO_3 FGC
I_s = SO_3 injection rate	4-9
= N/A ppmv at 6% O_2, wet	default value = 7 ppmv if before APH
$F3_{FGC}$ = Technology impact factor	4-9 — 5 ppmv if after APH
= 0.17 *unitless*	4-9 (for PRB coal)
$NH3_{SCR}$ = Ammonia slip produced from SCR/SNCR	4-13
= 0 lb/year	SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)
$F2_{APH}$ = Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive	4-12
= 0.36 for air heater	4-18 (Table 4-3 for PRB)
$NH3_{FGC}$ = Ammonia produced from FGC	4-14
= $K_e * B * f_e * I_{NH3}$ — $NH3_{FGC\_beforeAPH}$ = 0.00 lb/year	4-14 (Eqn 4-14)
$NH3_{FGC\_afterAPH}$ = 0.00 lb/year	
where K_e = *3,799*	*see above*
B = *82.12*	*see above*
f_e = *0* unitless	No Ammonia FGC
I_{NH3} = NH_3 injection for dual FGC	4-14
= N/A ppmv at 6% O_2, wet	default value = 3 ppmv
$F2_X$ = Technology impact factors for processes downstream of the APH (product of all that apply)	4-12
= 0.01 for dry FGD and baghouse	4-20 (Table 4-4 for PRB)

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

PM Speciation Calculations

Entergy White Bluff
Unit 2 Boiler - DFGD with Fabric Filter

Controlled PM10 Speciation from AP-42 Tables 1.1-5 & 1.1-6
Dry Bottom Boiler burning Pulverized Coal using FGD+FF for Emissions control

*Assumes heating value of **8,587** Btu/lb and a sulfur content of **0.27** % and an ash content of **4.96** % and a heat input of **8,950** mmBtu/hr and f(RH) = **1**

	Controlled PM10 Emissions **(Bold** values from Table 1.1-5.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/mmBtu)	(lb/mmBtu)	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/ton)	Coef.	(lb/mmBtu)	Coef.	(lb/mmBtu)	(lb/mmBtu)	Type	Ext.Coef.	(lb/mmBtu)	Type	Ext.Coef.
PC-DB	0.0258	0.0058	0.0029	0.6	0.0029	0.0028	1	0.00011	10	**0.020**	**0.016**	SO4	3*f(RH)	**0.004**	SOA	4

	Controlled PM10 Emissions **(Bold** Values from Table 1.1-6.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/ton)	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Coef.	(lb/ton)	Coef.	(lb/ton)	(lb/ton)	Type	Ext.Coef.	(lb/ton)	Type	Ext.Coef.
PC-DB	0.443	**0.099**	0.050	0.6	**0.050**	0.048	1	0.0018	10	0.343	0.275	SO4	3*f(RH)	0.069	SOA	4

	Controlled PM10 Emissions															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(% of Total)	(% of Total)	(% of Total)	Coef.	(% of Total)	(% of Total)	Coef.	(% of Total)	Coef.	(% of Total)	(% of Total)	Type	Ext.Coef.	(% of Total)	Type	Ext.Coef.
PC-DB	100%	22.4%	11.2%	0.6	11.2%	10.8%	1	0.4%	10	77.6%	62.1%	SO4	3*f(RH)	15.5%	SOA	4

If you are given Total PM10 emissions in lb/hr:

	Controlled PM10 Emissions **(Bold** Value is **Input** by user.)															
Boiler	Total PM10	Filterable	Coarse	Ext.	Fine	Fine Soil	Ext.	Fine EC	Ext.	Condensible	CPM IOR	Particle		CPM OR	Particle	
Type	(lb/hr)	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Coef.	(lb/hr)	Coef.	(lb/hr)	(lb/hr)	Type	Ext.Coef.	(lb/hr)	Type	Ext.Coef.
PC-DB	**119.2**	26.7	13.4	0.6	13.4	12.9	1	0.5	10	92.5	74.0	SO4	3	18.5	SOA	4

*NOTE: Coal properties (i.e., heating value, sulfur content, and ash content) are averaged annual values from 2014 through 2016.

Override the estimated CPM IOR to the H_2SO_4 value calculated with EPRI methodology (below).
Remaining species are taken directly from the NPS calculations.

Coarse	**13.37**	**lb/hr**	(PMC)
Fine Soil	**12.87**	**lb/hr**	(PMF)
Fine EC	**0.49**	**lb/hr**	(EC)
CPM OR	**18.50**	**lb/hr**	(SOA)
CMP IOR	**0.01**	**lb/hr**	(SO_4)

Entergy White Bluff
Unit 2 Boiler (continued)

EPRI, *Estimating Total Sulfuric Acid Emissions from Stationary Power Plants (1023790)*, March 2012						Page Reference		
TSAR		=	Total sulfuric acid release					
		=	$\{[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})] * F2_{APH} + (EM_{FGC\_afterAPH} - NH3_{FGC\_afterAPH})\} * F2_x$			4-11 (Eqn 4-10)		
		=	49.27 lb/year					
where:								
EM_{Comb}	=		H_2SO_4 manufactured from combustion			4-1 (Eqn 4-1)		
	=		K * F1 * E2					
	=		13,687.27 lb/year					
where	K	=	Units conversion factor			4-1		
		=	3,063 lb H_2SO_4/ton SO_2			4-1		
	F1	=	Fuel Impact Factor			4-1		
		=	0.0019 *unitless*			4-6 (Table 4-1 for Subbituminous/PRB Coal)		
	E2	=	SO_2 emission rate			4-1		
		=	2,352.06 tons/yr (max day during 2014-2016)			Based on controlled emission factor (lb/MMBtu) and Maximum Unit Heat Input		
EM_{SCR}	=		H_2SO_4 manufactured from SCR/SNCR			4-7		
	=		0 lb/year			SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)		
EM_{FGC}	=		H_2SO_4 manufactured from flue gas conditioning					
	=		$K_e * B * f_e * I_s * F3_{FGC}$	$EM_{FGC\_beforeAPH}$ = 0.00	lb/year	4-9 (Eqn 4-7)		
				$EM_{FGC\_afterAPH}$ = 0.00	lb/year			
where	K_e	=	Conversion factor			4-9		
		=	3,799 lb H_2SO_4/(TBtu*ppmv SO_3 @ 6% O_2 and wet)			4-10 (Text Box B)		
	B	=	Coal burn			4-9		
		=	77.87 TBtu/yr (max day during 2014-2016)			Entergy CAMD data		
	f_e	=	Operating factor of FGC system - the fraction of coal burn when the FGC operates			4-9		
		=	0 *unitless*			No SO_3 FGC		
	I_s	=	SO_3 injection rate			4-9		
		=	N/A ppmv at 6% O_2, wet			default value =	7	ppmv if before APH
	$F3_{FGC}$	=	Technology impact factor			4-9	5	ppmv if after APH
		=	0.17 *unitless*			4-9 (for PRB coal)		
$NH3_{SCR}$	=		Ammonia slip produced from SCR/SNCR			4-13		
	=		0 lb/year			SCR/SNCR is not present (SCR/SNCR was evaluated as part of FFA)		
$F2_{APH}$	=		Technology impact factor for APH; only apply if $[(EM_{Comb} + EM_{SCR} + EM_{FGC\_beforeAPH}) - (NH3_{SCR} + NH3_{FGC\_beforeAPH})]$ is positive			4-12		
	=		0.36 for air heater			4-18 (Table 4-3 for PRB)		
$NH3_{FGC}$	=		Ammonia produced from FGC			4-14		
	=		$K_e * B * f_e * I_{NH3}$	$NH3_{FGC\_beforeAPH}$ = 0.00	lb/year	4-14 (Eqn 4-14)		
				$NH3_{FGC\_afterAPH}$ = 0.00	lb/year			
where	K_e	=	*3,799*			*see above*		
	B	=	*77.87*			*see above*		
	f_e	=	*0* unitless			No Ammonia FGC		
	I_{NH3}	=	NH_3 injection for dual FGC			4-14		
		=	N/A ppmv at 6% O_2, wet			default value =	3	ppmv
$F2_X$	=		Technology impact factors for processes downstream of the APH (product of all that apply)			4-12		
	=		0.01 for dry FGD and baghouse			4-20 (Table 4-4 for PRB)		

Notes:
1. The PM speciation workbook was obtained from National Park Service website (http://www.nature.nps.gov/air/permits/ect/index.cfm
2. SO_4 emissions are calculated using the EPRI Method, as outlined in the reference document:
   "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants". Electric Power Research Institute (EPRI). Technical Update, March 2012
3. PM_{10} emission rate is based on maximum HI rating and AP-42 emission factors.

Entergy Services, Inc., on behalf of Entergy Arkansas, Inc.
White Bluff Steam Electric Station
Redfield, Arkansas (AFIN 35-00110)

Updated BART Five-Factor Analysis for SO_2 for Units 1 and 2

Submitted to:

Arkansas Department of Environmental Quality (ADEQ)
Office of Air Quality
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August 18, 2017

Trinity Project 173702.0014

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1 EXECUTIVE SUMMARY

This report provides an update to the Best Available Retrofit Technology (BART) Five Factor Analysis for sulfur dioxide (SO_2) for Unit 1 (SN-01) and Unit 2 (SN-02) at Entergy Arkansas, Inc.'s (EAI's) White Bluff Steam Electric Station (White Bluff) as well as revising the SO_2 BART conclusion. EAI submitted the original BART Five Factor Analysis to the Arkansas Department of Environmental Quality (ADEQ) on February 21, 2013, with revisions on June 10, 2013 and October 15, 2013.

- Unit 1 (SN-01) is a primary boiler with a maximum net power rating of 850 megawatts (MW) and a nominal heat input capacity of 8,950 million British thermal units per hour (MMBtu/hr). The boiler burns sub-bituminous or bituminous coal[1] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an electrostatic precipitator (ESP) for particulate matter (PM) control.
- Unit 2 (SN-02) is identical in design to Unit 1. It is a primary boiler with a maximum net power rating of 850 MW and a nominal heat input capacity of 8,950 MMBtu/hr. The boiler burns sub-bituminous or bituminous coal[2] as the primary fuel and No. 2 fuel oil or biofuel as a start-up fuel, and it is currently equipped with an ESP for PM control.

Specific updates incorporated in this version of the report are outlined below.

1.1 REPORT UPDATES

This report includes the following updates to the previous SO_2 Five Factor Analysis for White Bluff Units 1 and 2:

1. Updating the baseline period to 2009-2013.
2. Incorporating new information regarding the remaining useful life (RUL) of the units.
3. Incorporating a new control scenario representing combustion of only low-sulfur coal (LSC).
4. Incorporating additional information (i.e., cost information and modeling results) related to control options involving Dry Sorbent Injection (DSI).
5. Updating all modeling to reflect the newest methodologies for dividing ("speciating") particulate matter (PM or PM_{10})[3] emissions into its constituents.
6. Updating the SO_2 BART conclusion in consideration of the new information and updates listed above.

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[1] The coal-fired units at White Bluff primarily burn sub-bituminous coal, but are permitted to burn bituminous or sub-bituminous coal. Only sub-bituminous coals were burned during the baseline periods evaluated in this analysis.

[2] Ibid.

[3] All PM represented in this report is assumed to have a mass mean diameter smaller than ten microns.

1.2 SUMMARY OF UPDATED BART FIVE FACTOR ANALYSIS

Trinity conducted the below five-step analysis based on EPA's BART Guidelines[4] in 40 CFR Part 51 and other EPA guidance[5] to evaluate SO_2 BART for Units 1 and 2:

1. Identifying all available retrofit control technologies;
2. Eliminating technically infeasible control technologies;
3. Evaluating the control effectiveness of remaining control technologies;
4. Evaluating impacts and documenting the results; and
5. Evaluating visibility impacts.

The updated BART Five Factor Analysis concludes that combustion of LSC constitutes BART for Unit 1 and Unit 2 in light of the updated RUL. The proposed BART emission rate for SO_2 is 0.6 pounds per MMBtu (lb/MMBtu) on a rolling 30-day average.

[4] The BART guidelines were published as amendments to EPA's Regional Haze Rule (RHR) at 40 CFR 51.308 on July 6, 2005.

[5] April 26, 2012, letter from Mr. Guy Donaldson, EPA Region VI, to Mr. Anthony Davis, ADEQ.

2 INTRODUCTION AND BACKGROUND

In the 1977 amendments to the Clean Air Act (CAA), Congress set a national goal to restore national parks and wilderness areas to pristine conditions by preventing any future, and remedying any existing, man-made visibility impairment. On July 1, 1999, the U.S. EPA published the final Regional Haze Rule (RHR). The objective of the RHR is to restore visibility to pristine conditions in 156 specific areas across the United States known as Class I areas. The CAA defines Class I areas as certain national parks (larger than 6,000 acres), wilderness areas (larger than 5,000 acres), national memorial parks (larger than 5,000 acres), and international parks that were in existence on August 7, 1977.

The RHR requires States to set goals that provide for reasonable progress towards achieving natural visibility conditions for each Class I area in their state. On July 6, 2005, the EPA published amendments to its 1999 RHR, often called the Best Available Retrofit Technology (BART) rule, which included guidance for making source-specific BART determinations. The BART rule defines BART-eligible sources as sources that meet the following criteria:

(1) Have potential emissions of at least 250 tons per year of a visibility-impairing pollutant,
(2) Began operation between August 7, 1962, and August 7, 1977, and
(3) Are included as one of the 26 listed source categories in the guidance.

A BART-eligible source is subject to BART if the source is "reasonably anticipated to cause or contribute to visibility impairment in any federal mandatory Class I area." For the purpose of determining which sources are subject to BART, a 1.0 Δdv change or more from an individual source is considered to "cause" visibility impairment, and a change of 0.5 Δdv is considered to "contribute" to impairment, which therefore establishes 0.5 Δdv as a numerical screening threshold for subject-to-BART determinations.[6] According to the BART guidelines, the CALPUFF modeling system (CALPUFF) or any other appropriate dispersion model can be used to predict the visibility impacts.[7] The model-predicted visibility impact, specifically when using CALPUFF the 98th percentile impact measured against natural background (and not the maximum impact), is compared to the 0.5 Δdv threshold to determine if the source is anticipated to cause or contribute to the visibility impairment.[8]

Once it is determined that a source is subject to BART, a BART determination must address air pollution control measures for the source. The visibility regulations define BART as follows:

> *…an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by…[a BART-eligible source]. The emission limitation must be established on a case-by-case basis, taking into consideration the technology available, the cost of compliance, the energy and non-air quality*

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[6] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule," 70 Fed. Reg. 39,116-18 (July 6, 2005).

[7] Trinity and EAI assert that CALPUFF is not the most appropriate model for estimating visibility impacts. Due to its numerous inherent limitations (e.g., limited chemistry mechanism, distance limitations, blanket background ammonia values, etc.), CALPUFF does not yield reliable results. Furthermore, CALPUFF is no longer an EPA-preferred model, which further indicates CALPUFF's unreliability. More advanced models like the Comprehensive Air Quality Model with Extensions (CAMx)—if processed appropriately—can yield more reliable characterizations of visibility impairment. Nevertheless (without waiver), CALPUFF modeling will continue to be presented in this report for consistency with past submittals.

[8] Id. at 39,163.

environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

The BART Guidelines state that a BART determination should address the following five statutory factors:

1. Existing controls;
2. Cost of controls;
3. Energy and non-air quality environmental impacts;
4. Remaining useful life of the source; and
5. Degree of visibility improvement as a result of controls.

Further, the BART Guidelines indicate that the five basic steps in a BART analysis can be summarized as follows:

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

As described in the above-referenced, previous submittals, the boilers at White Bluff meet the three BART-eligibility criteria, and the existing visibility impairment is modeled at greater than 0.5 Δdv in at least one Class I area. Thus, the White Bluff units are subject to BART.

3 EXISTING EMISSIONS AND BASELINE VISIBILITY IMPAIRMENT

Five Factor Analyses require the determination of unit-specific baseline visibility impairment values to which any post-control scenarios can be compared. The unit-specific baseline modeling analyses are built upon, but are distinguished from, the baseline (a.k.a., "screening") modeling for the collection of BART eligible units at each source that is completed to determine if a BART eligible source is subject to BART. EAI is not updating the subject-to-BART determination at this time.

This section summarizes the baseline visibility impairment attributable to each of White Bluff's units based on CALPUFF air quality modeling conducted by Trinity.[9] Trinity conducted the modeling using the same protocol, methodologies, and inputs (except where specifically updated as described in this report) as presented in the October 15, 2013 submittal. The protocol and details method descriptions are not included with this report because nothing has changed and the CALMET dataset developed per the protocol has been used – and approved by EPA – numerous times since its development.

While this report updates the BART Five Factor Analysis for SO_2 emissions specifically, BART modeling must consider emissions of all visibility-affecting pollutants (VAP), including SO_2, oxides of nitrogen (NO_X), and speciated particulate matter, including filterable coarse particulate matter (PMc), filterable fine particulate matter (PMf), elemental carbon (EC), inorganic condensable particulate matter (IOR CPM) as sulfates (SO_4), and organic condensable particulate matter (OR CPM), also referred to as secondary organic aerosols (SOA).

3.1 BASELINE EMISSION RATES

The updated modeled NO_X and SO_2 emission rates for Unit 1 and Unit 2 are the highest actual 24-hour emission rates based on Clean Air Markets Database (CAMD) data from 2009-2013.[10] The updated modeled PM_{10} emission rates for Unit 1 and Unit 2 are based on emission factors from AP-42 for filterable PM_{10} and condensable PM (with a 99.5 percent control efficiency for ESP applied to the PM_{10} filterable fraction) used in conjunction with the average 2009-2013 coal heating value and ash content (as a percentage of mass).[11] Emission rates for specific PM_{10} species were calculated using the monitored filterable PM rate and the National Park Service (NPS) "speciation spreadsheet" for *Dry Bottom Boiler Burning Pulverized Coal using only ESP*[12] except for SO_4, which was calculated using an Electric Power Research Institute (EPRI) methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[13] Table 3-1 summarizes the emission rates that were modeled for SO_2, NO_X, and PM_{10}, including the speciated PM_{10} emissions.

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[9] See footnote 7, above.

[10] The use of this baseline is a conservative approach. EAI would be justified in using a more recent baseline with lower emissions that would result in higher cost effectiveness values.

[11] AP-42, Chapter 1 External Combustion Sources, Section 1.1 Bituminous and Subbituminous Coal Combustion, Table 1.1-5, page 1.1-24 (September 1998).

[12] The baseline speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. Based on average 2009-2013 values, the following input values were used: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at both White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[13] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 3-1. Baseline Maximum 24-hour Emission Rates (As Hourly Equivalents)

Unit	SO_2 (lb/hr)	NO_X (lb/hr)	Total PM_{10} (lb/hr)	SO_4 (lb/hr)	PM_c (lb/hr)	PM_f (lb/hr)	SOA (lb/hr)	EC (lb/hr)
SN-01	6,771.9	3,355.4	119.2	5.1	40.4	31.1	9.3	1.2
SN-02	6,622.3	3,590.5	119.2	5.0	40.4	31.1	9.3	1.2

3.2 BASELINE VISIBILITY IMPAIRMENT

Trinity conducted modeling to estimate the current visibility impairment attributable to Unit 1 and Unit 2 in four Class I Areas: Caney Creek Wilderness (CACR), Upper Buffalo Wilderness (UPBU), Hercules Glades Wilderness (HERC), and Mingo Wilderness (MING) using the CALPUFF dispersion model.[14] Table 3-2 provides a summary of the modeled visibility impairment attributable to Unit 1 and Unit 2 based on the emission rates shown in Table 3-1. This table shows the 98th percentile impacts in Δdv and the number of days with impacts greater than 0.5 Δdv.

Table 3-2. Baseline Visibility Impairment

Unit	Year [A]	CACR		UPBU		HERC		MING	
		98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5
SN-01	2001	1.505	38	1.051	30	0.925	24	0.802	16
	2002	1.306	29	0.742	15	0.567	10	0.708	21
	2003	1.053	32	1.033	24	0.704	15	0.666	14
SN-02	2001	1.533	39	1.059	30	0.912	25	0.819	15
	2002	1.322	29	0.739	16	0.568	11	0.719	20
	2003	1.059	32	1.03	25	0.72	16	0.678	14

[A] Meteorological data year modeled.

[14] Due to an EPA-requested change in meteorological data (to a refined, or "NO OBS = 0", dataset), which excluded the Sipsey Class 1 Area from the modeling domain, Sipsey was not included in this analysis. See also footnote 7 above.

4.1 IDENTIFICATION OF AVAILABLE RETROFIT SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

The boilers burn primarily coal. Sulfur oxides, SO_X, are generated during coal combustion from the oxidation of sulfur contained in the fuel. SO_X emissions are almost entirely dependent on the sulfur content of the fuel and are generally not affected by boiler size or burner design. SO_X emissions from conventional combustion systems are predominantly in the form of SO_2. Since SO_2 is the predominant sulfur compound emitted from Unit 1 and Unit 2, the BART analysis is specific to emissions of SO_2. Reductions in emissions of SO_2 are expected to reduce visibility impairment by reducing sulfate (SO_4) formation.

Step 1 of the top-down control review is to identify available retrofit control options for SO_2. The available SO_2 retrofit control technologies for Unit 1 and Unit 2 are summarized in Table 4-1.

Table 4-1. Available SO_2 Control Technologies for Unit 1 and Unit 2

SO_2 Control Technologies
Fuel Switching – Low-Sulfur Coal (LSC)
Dry Sorbent Injection (DSI)
Dry / Semi-Dry Flue Gas Desulfurization (DFGD), e.g., Spray Dryer Absorber (SDA)
Wet Scrubbing, i.e., Wet Flue Gas Desulfurization (WFGD)

4.2 ELIMINATE TECHNICALLY INFEASIBLE SO_2 CONTROL TECHNOLOGIES FOR UNIT 1 AND UNIT 2

Step 2 of the BART determination is to eliminate technically infeasible SO_2 control technologies that were identified in Step 1.

4.2.1 Fuel Switching - Low-Sulfur Coal

With an achievable emission level of 0.6 lb/MMBtu, switching to LSC can reduce SO_2 emissions by approximately 8.75 percent compared to baseline levels.[15]

4.2.2 Dry Sorbent Injection

DSI involves the injection of a sorbent (e.g., Trona) into the exhaust gas stream where acid gases such as hydrogen chloride (HCl) and SO_2 react with and become entrained in the sorbent. The stream then passes through a particulate control device to remove the sorbent along with the entrained SO_2. The process was developed as a lower cost FGD option because the mixing of the SO_2 and sorbent occurs directly in the exhaust gas stream rather than in a separate vessel. Sorbent injection control efficiency depends on residence time, gas stream temperature, and limitations of the particulate control device.

[15] Calculated based on a comparison of the maximum 30 boiler operating day SO_2 emission rate during the baseline period to the proposed limit for low-sulfur coal of 0.6 lb/MMBtu.

DSI is a technically feasible yet seldom used technology for moderate to high removal of SO_2 from coal-fired power plants, with limited full-scale installations for SO_2 control. A significant amount of testing of DSI for SO_2 control has been performed in recent years. This testing has shown that a wide range of performance is achievable (up to 80 or 90 percent SO_2 reduction in some cases). However, this testing has also shown that there are many factors that can impact the performance of these reagents, including particle size (milling), residence time, temperature, and the particulate collection equipment. The primary lesson learned through this testing is that each unit is unique, with various factors that can impact the achievable performance or required reagent feed rate. Different performance has even been seen on sister units. Therefore, it is critical to perform a demonstration or Proof of Concept test at each facility.

A demonstration has not to-date been performed on the White Bluff units to show the achievable SO_2 control and associated reagent feed rates. The cost reports developed by S&L, included in Appendix A, show predicted performance and required reagent rates based on Sargent & Lundy's (S&L's) extensive experience with DSI testing and previous work with the White Bluff units. Two DSI technologies are considered for White Bluff: "DSI", which would utilize the existing ESP, and "enhanced DSI", which would include installation of a fabric filter or baghouse. Enhanced DSI should achieve greater SO_2 reductions because the installation of a fabric filter increases residence time and improves collection efficiency to allow more sorbent to be injected. The S&L reports present predicted performance levels (SO_2 emission rates) for DSI and enhanced DSI of 0.35 lb/MMBtu and 0.15 lb/MMBtu, respectively. Because the actual performance and required reagent rates may vary from the predicted values due to unforeseen site-specific conditions, it is possible that the capital and annual costs represented in the S&L reports, and in Section 4.4.2 of this report, could also vary. If a significantly higher injection rate were actually required to achieve the same performance level (SO_2 emission rate) then the capital and annual costs, and corresponding cost-effectiveness of the DSI technologies, could dramatically increase.

Furthermore, DSI has yet to be demonstrated on similarly sized units to those at White Bluff. An important consideration for DSI technology is the design throughput of the system, beyond just the size and achievable performance (SO_2 emission rate). The largest DSI system installed and operating has a design feed rate of 12 tons/hour, while most of the installed systems inject approximately five to six tons/hour. The predicted injection rate for the White Bluff enhanced DSI case is approximately 15 tons/hour. The greater the injection rates, the more issues associated with supply and delivery logistics that arise. At 15 tons/hour (per unit) White Bluff would consume one railcar (100-ton capacity) of Trona every 3.3 hours if both units are operating at full load.

Prior to moving forward with DSI technology as a compliance strategy, a demonstration test would need to be performed to confirm the feasibility, achievable performance and balance of plant impacts (brown plume formation, ash handling modifications, landfill/leachate considerations and impact to mercury control). The balance of plant impacts have been addressed as part of the S&L cost reports based on typical assumptions, but would also be impacted should the design injection rate vary. Any compliance strategy which were to rely on DSI technology would need to be contingent on successful completion of a demonstration test.

4.2.3 Dry / Semi-Dry Flue Gas Desulfurization

Of the various designs for dry or semi-dry FGD systems, the most popular is the Spray Dryer Absorber (SDA) design. In the SDA design, a fine mist of lime slurry is sprayed into an absorption tower 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 heat from the exhaust gas causes the water to evaporate before the droplets reach the bottom of the tower, resulting in the formation of a dry powder that is carried out with the gas and collected with a fabric filter.

SDA systems can achieve control efficiencies ranging from 60 to 95 percent.[16] SDA is a technically feasible option for control of SO_2 from Unit 1 and Unit 2. Based on a site-specific study completed by S&L, SDA could technically achieve an SO_2 emission rate of 0.06 lb/MMBtu at Unit 1 and Unit 2.

4.2.4 Wet Flue Gas Desulfurization

While WFGD is technically feasible, it is not expected to achieve significant reductions beyond DFGD/SDA and was eliminated in the previous analyses and in EPA's final regulations (SIP approval and FIP). Accordingly, WFGD is not considered further in this analysis.

4.3 RANK OF TECHNICALLY FEASIBLE SO_2 CONTROL OPTIONS BY EFFECTIVENESS FOR UNIT 1 AND UNIT 2

The third step in the BART analysis is to rank the technically feasible options according to their effectiveness in reducing SO_2.
Table 4-2Table 4-2 provides a ranking of the control levels for the controls listed in the previous section.

Table 4-2. Control Effectiveness of Technically Feasible SO_2 Control Technologies

Control Technology	Achievable Emission Rate (lb/MMBtu) [A]
Semi-Dry Scrubber (SDA)	0.06
Enhanced DSI	0.15
DSI	0.35
Low Sulfur Coal	0.6

4.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

The fourth step in the BART analysis is the impact analysis, which evaluates the impacts for the control options deemed feasible in Step 2. This analysis typically is conducted to demonstrate that the most effective control technology does not necessarily constitute BART. The BART guidelines list the four factors to be considered in the impact analysis:

- Cost of compliance
- Energy impacts
- Non-air quality impacts; and
- The RUL of the source

Because the RUL of the source directly affects the cost of compliance, RUL is considered first.

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

4.4.1 Remaining Useful Life

EAI anticipates Unit 1 and Unit 2 will cease to use coal by end of year 2028, and, upon acceptance of the BART determinations contained herein in an approved SIP, is prepared to take an enforceable restriction to this effect.

4.4.2 Cost of Compliance

The capital costs and annual operating and maintenance costs for the considered control options, except for the LSC option, were developed by S&L and are included in Appendix A. The annual cost increase due to burning only LSC is based on a cost premium of $0.50 per ton, which was the premium provided to EAI's fuel purchasing department by its coal suppliers. For the S&L-developed costs, two sets of values are presented. The first, in Table 4-3, is the actual cost estimated for each unit and control option. The second, in Table 4-4Table 4-4, is the estimated cost after excluding cost items that EPA has historically claimed should not be accounted for in BART cost effectiveness calculations. An example of an excluded cost is Allowance for Funds Used During Construction (AFUDC). AFUDC represents the interest expense incurred on the investment in a large capital project, such as a FGD installation, which can take several years to complete (≥ 5 years). Although interest expenses will certainly be incurred on such a project, and AFUDC is typically considered as part of the capital cost of such a project for standard accounting and rate-making purposes, EPA Region 6 has expressed concern with the inclusion of AFUDC and certain other costs. EAI disagrees and believes that determining the cost effectiveness of the control options must realistically reflect the actual cost of compliance. *See* EAI's comments on the proposed FIP.[17] Nonetheless, for completeness, this analysis shows a range of cost effectiveness both including AFUDC and other costs and excluding those costs.

Trinity annualized the capital costs based on capital recovery periods reflecting the total amount of time that the control option could be employed until the unit ceases to use coal at the end of 2028. For the purpose of this report, the start of operation for the SDA option is assumed to be the end of 2021.[18] Therefore, the capital recovery period for SDA is set at seven (7) years (2028 – 2021 = 7 years). The LSC and DSI options can be employed two (2) years earlier than SDA which, for purposes of this report, is assumed to be the end of 2019. Therefore, the capital recovery period for these control options is set at nine (9) years (2028 – 2019 = 9 years).

Trinity determined the values for annual tons of SO_2 reduced by subtracting the estimated controlled annual emission rate from the baseline annual emission rate. The baseline annual emission rate was based on the average rate for the 2009-2013 baseline period.[19] The controlled annual emission rates were based on the lb/MMBtu levels listed in Table 4-2 multiplied by the future annual heat input, which was based on the average actual heat input from CAMD for the 2009-2013 baseline period. For the LSC scenario, "controlled" annual emission rates were based on an 8.75 percent decrease compared to baseline annual emission rates, which is estimated by comparing the maximum 30-boiler operating day rolling average to the controlled emission rate of 0.6 lb/MMBtu.

The cost effectiveness in dollars per ton of SO_2 reduced was determined by dividing the annualized cost of control by the annual tons reduced. Table 4-3 presents a summary of the cost effectiveness for each control

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[17] Entergy Arkansas Inc. "Comments On the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas" (EPA Docket ID No. EPA-R06-OAR-2015-0189), August 7, 2015, pp. 10-11.

[18] October 27, 2021 per 81 Fed. Reg. Vol. 81, p. 66416. However, given that actual installation would take at least five years, SDA likely could not be installed until 2023 or later.

[19] As noted above, this is a conservative baseline, and EAI would have been justified in using a more recent baseline with lower emissions that would have resulted in generally higher cost effectiveness values.

option. The cost of switching to low sulfur coal is less than $1,200/ton of SO_2 reduced. The actual cost effectiveness of the add-on controls is economically infeasible at more than $7,000/ton of SO_2 reduced. It's noted (without waiver) that the cost effectiveness of add-on controls even when excluding certain costs for which EPA has expressed concern (e.g., AFUDC), but that will be incurred as explained above, also results in economic infeasibility, at more than approximately $5,400/ton.[20]

Table 4-3. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Actual Costs

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	190.11	29.18	14.91	7,148	8,900
SN-02 – DSI	16,034	9,807	190.11	29.18	14.91	7,081	8,807
SN-01 – Enhanced DSI	15,939	4,187	393.74	60.44	26.19	7,372	8,209
SN-02 – Enhanced DSI	16,034	4,203	393.74	60.44	26.19	7,322	8,153
SN-01 – SDA	15,939	1,675	495.74	92.01	9.60	7,124	7,771
SN-02 – SDA	16,034	1,681	495.74	92.01	9.60	7,080	7,722

Table 4-4. Summary of SO_2 Controls Cost Effectiveness for Unit 1 and Unit 2 Based on Costs Adjusted for EPA-Exclusions for Illustration Purposes

Unit & Control Option	Baseline Emission Rate (tpy)	Controlled Emission Rate (tpy)	Capital Cost ($MM)	Annualized Capital Cost ($MM/yr)	Annual O&M Cost ($MM/yr)	Average Cost Effective-ness ($/ton)	Incremental Cost Effective-ness v. LSC ($/ton)
SN-01 – LSC	15,939	14,544	0	0	1.60	1,150	
SN-02 – LSC	16,034	14,631	0	0	1.61	1,148	
SN-01 – DSI	15,939	9,770	154.79	23.76	14.91	6,269	7,764
SN-02 – DSI	16,034	9,807	154.79	23.76	14.91	6,211	7,683
SN-01 – Enhanced DSI	15,939	4,187	321.42	49.34	26.19	6,427	7,137
SN-02 – Enhanced DSI	16,034	4,203	321.42	49.34	26.19	6,384	7,088
SN-01 – SDA	15,939	1,675	364.83	67.71	9.60	5,420	5,883
SN-02 – SDA	16,034	1,681	364.83	67.71	9.60	5,387	5,846

[20] Issues raised on appeal of the federal plan include EPA's use of undervalued cost of controls. However, without waiver of any claims or arguments, EPA's estimates also support the conclusion that SDA is not cost effective. Using EPA's estimates of capital cost ($247,709,875), total O&M cost ($16,877,127), and emissions reductions (14,363 tpy for Unit 1 and 15,221 tpy for Unit 2), adjusted only to consider the shortened remaining useful life value discussed above, the average cost effectiveness values for SDA are $4,376/ton for Unit 1 and $4,129 for Unit 2.

4.4.3 Energy Impacts and Non-Air Quality Impacts

There are numerous energy impacts and adverse non-air quality environmental impacts associated with the add-on controls under consideration. Some examples related to the use of DSI include (a) the need for substantial storage and transportation – both delivery via rail and conveyance on site – of Trona, (b) the forced abandonment of the beneficial re-use of fly ash, and (c) potential negative impacts on the PM control device.[21] These impacts are more fully addressed for all the considered control options in the S&L reports included in Appendix A.

4.5 EVALUATION OF VISIBILITY IMPACT OF FEASIBLE SO_2 CONTROLS FOR UNIT 1 AND UNIT 2

Trinity conducted an impact analysis to assess the visibility improvement achieved. The impact analysis compared the impacts associated with the baseline emission rates to the impacts associated with the maximum emission rates representative of each control option.

Table 4-5 summarizes the lb/hr emission rates that were modeled to reflect each control option. The NO_X and total PM_{10} emission rates were modeled at the revised 2009-2013 baseline rates. The applicable NPS speciation spreadsheets were relied upon to determine emission rates for PM species.[22,23,24] SO_4 emission rates were independently calculated using an EPRI methodology that considers the SO_2 to SO_4 conversion rate and SO_4 reduction factors for various downstream equipment.[25]

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[21] Sargent & Lundy, *Entergy Arkansas, Inc. White Bluff DSI Cost Estimate Basis Document*, SL-014000 Final, Rev. 0, August 3, 2017, pp. 6-10. *See* Appendix A of this report.

[22] Low sulfur coal PM speciation is based on the NPS Workbook for a Dry Bottom Boiler burning Pulverized Coal using an ESP. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: http://www.nature.nps.gov/air/Permits/ect/index.cfm.

[23] DSI and Enhanced DSI PM speciations are based on the NPS workbooks for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with an ESP or Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr heat input, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[24] DFGD speciation is based on the NPS workbook for a Dry Bottom Boiler burning Pulverized Coal using an FGD system with a Fabric Filter. The following values were input: heating value of 8,587 Btu/lb, 0.27% sulfur, 4.96% ash, 8,950 MMBtu/hr, and a baseline total PM_{10} emission rate of 119.2 lb/hr at White Bluff Unit 1 and Unit 2. NPS: Ibid.

[25] Electric Power Research Institute (EPRI) Estimating Total Sulfuric Acid Emissions from Stationary Power Plants: EPRI, Technical Update, Palo Alto, CA: March 2012. 1023790.

Table 4-5. Emission Rates Modeled to Reflect SO_2 Controls for Unit 1 and Unit 2

Unit & Control Option	SO_2 (lb/hr)	SO_4 [A] (lb/hr)	NO_X (lb/hr)	PM_C (lb/hr)	PM_F (lb/hr)	EC (lb/hr)	SOA (lb/hr)	Total PM_{10} (lb/hr)
SN-01 – LSC	5,370.0	4.0	3,355.4	40.4	31.1	1.2	9.3	119.2
SN-02 – LSC	5,370.0	4.0	3,590.5	40.4	31.1	1.2	9.3	119.2
SN-01 – DSI	3,132.5	0.5	3,355.4	29.0	22.4	0.9	13.4	119.2
SN-02 – DSI	3,132.5	0.5	3,590.5	29.0	22.4	0.9	13.4	119.2
SN-01 – Enhanced DSI	1,342.5	0.02	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – Enhanced DSI	1,342.5	0.02	3,590.5	13.4	12.9	0.5	18.5	119.2
SN-01 – SDA	537.0	0.01	3,355.4	13.4	12.9	0.5	18.5	119.2
SN-02 – SDA	537.0	0.01	3,590.5	13.4	12.9	0.5	18.5	119.2

[A] SO_4 as it is displayed in this table represents ammonium sulfate.

Comparisons of the existing/baseline visibility impacts and the post-control visibility impacts are provided in Table 4-6 and Table 4-7.

Table 4-6. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 1 (Across All Modeled Years, 2001-2003)

Scenario	CACR		UBPU		HERC		MING	
	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv
Baseline	1.505	99	1.051	69	0.925	49	0.802	51
LSC	1.376	89	0.908	54	0.758	34	0.687	40
Improvement over baseline	*0.129*	*10*	*0.143*	*15*	*0.167*	*15*	*0.115*	*11*
DSI	1.197	64	0.676	30	0.584	19	0.469	17
Improvement over baseline	*0.308*	*35*	*0.375*	*39*	*0.341*	*30*	*0.333*	*34*
Improvement over LSC	*0.179*	*25*	*0.232*	*24*	*0.174*	*15*	*0.218*	*23*
Enhanced DSI	1.013	41	0.496	14	0.458	11	0.366	6
Improvement over baseline	*0.492*	*58*	*0.555*	*55*	*0.467*	*38*	*0.436*	*45*
Improvement over LSC	*0.363*	*48*	*0.412*	*40*	*0.300*	*23*	*0.321*	*34*
Improvement over DSI	*0.184*	*23*	*0.180*	*16*	*0.126*	*8*	*0.103*	*11*
SDA	0.902	35	0.409	7	0.400	6	0.298	2
Improvement over baseline	*0.603*	*64*	*0.642*	*62*	*0.525*	*43*	*0.504*	*49*
Improvement over LSC	*0.474*	*54*	*0.499*	*47*	*0.358*	*28*	*0.389*	*38*
Improvement over DSI	*0.295*	*29*	*0.267*	*23*	*0.184*	*13*	*0.171*	*15*
Improvement over Enhanced DSI	*0.111*	*6*	*0.087*	*7*	*0.058*	*5*	*0.068*	*4*

Table 4-7. Summary of CALPUFF-Modeled Visibility Impacts from SO_2 Controls for Unit 2 (Across All Modeled Years, 2001-2003)

Scenario	CACR		UBPU		HERC		MING	
	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv	98% Impact (Δdv)	# Days > 0.5 Δdv
Baseline	1.533	100	1.059	71	0.912	52	0.819	49
LSC	1.436	89	0.932	55	0.775	35	0.697	41
Improvement over baseline	*0.097*	*11*	*0.127*	*16*	*0.137*	*17*	*0.122*	*8*
DSI	1.259	66	0.700	31	0.609	19	0.486	18
Improvement over baseline	*0.274*	*34*	*0.359*	*40*	*0.303*	*33*	*0.333*	*31*
Improvement over LSC	*0.177*	*23*	*0.232*	*24*	*0.166*	*16*	*0.211*	*23*
Enhanced DSI	1.073	42	0.528	17	0.483	12	0.384	7
Improvement over baseline	*0.460*	*58*	*0.531*	*54*	*0.429*	*40*	*0.435*	*42*
Improvement over LSC	*0.363*	*47*	*0.404*	*38*	*0.292*	*23*	*0.313*	*34*
Improvement over DSI	*0.186*	*24*	*0.172*	*14*	*0.126*	*7*	*0.102*	*11*
SDA	0.959	37	0.427	12	0.426	8	0.318	3
Improvement over baseline	*0.574*	*63*	*0.632*	*59*	*0.486*	*44*	*0.501*	*46*
Improvement over LSC	*0.477*	*52*	*0.505*	*43*	*0.349*	*27*	*0.379*	*38*
Improvement over DSI	*0.300*	*29*	*0.273*	*19*	*0.183*	*11*	*0.168*	*15*
Improvement over Enhanced DSI	*0.114*	*5*	*0.101*	*5*	*0.057*	*4*	*0.066*	*4*

4.6 BART FOR SO_2 FOR UNIT 1 AND UNIT 2

Based on the costs of the control options listed above, BART for Unit 1 and Unit 2, when considering the updated RUL, would be an emission level of 0.6 lb/MMBtu based on the use of low-sulfur coal.

APPENDIX A. CONTROL COST INFORMATION

SO_2 CONTROL COST INFORMATION – LAST UPDATED AUGUST 2017

Table B-8. Baseline Visibility Impairment Attributable to Unit 1 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.912	1.505	38	74.33	25.34	0.17	0.15
2002	2.048	1.306	29	61.53	34.59	0.83	3.04
2003	4.020	1.053	32	47.92	50.35	0.35	1.39
Upper Buffalo							
2001	2.089	1.051	30	68.58	31.17	0.26	0.00
2002	1.438	0.742	15	79.11	20.19	0.37	0.32
2003	1.773	1.033	24	79.79	19.92	0.28	0.00
Hercules Glades							
2001	1.643	0.925	24	90.21	9.56	0.23	0.00
2002	1.184	0.567	10	74.20	25.45	0.25	0.10
2003	1.977	0.704	15	86.02	13.73	0.25	0.00
Mingo							
2001	1.538	0.802	16	51.46	48.03	0.39	0.12
2002	0.898	0.708	21	54.87	44.82	0.31	0.01
2003	1.003	0.666	14	57.31	41.18	0.41	1.11

Table B-9. Baseline Visibility Impairment Attributable to Unit 2 by Pollutant

Year	Maximum (Δdv)	98th Percentile (Δdv)	No. of Days with Δdv ≥ 0.5	98th Percentile % SO_4	98th Percentile % NO_3	98th Percentile % PM_{10}	98th Percentile % NO_2
Caney Creek							
2001	2.994	1.533	39	36.23	60.75	0.74	2.28
2002	2.098	1.322	29	59.43	36.53	0.82	3.22
2003	4.084	1.059	32	96.37	3.38	0.24	0.01
Upper Buffalo							
2001	2.066	1.059	30	66.54	33.21	0.26	0.00
2002	1.447	0.739	16	77.57	21.71	0.37	0.35
2003	1.791	1.030	25	78.24	21.46	0.28	0.00
Hercules Glades							
2001	1.665	0.912	25	89.39	10.38	0.23	0.00
2002	1.185	0.568	11	72.38	27.26	0.25	0.11
2003	1.947	0.720	16	40.35	58.44	0.40	0.82
Mingo							
2001	1.580	0.819	15	81.62	17.93	0.33	0.12
2002	0.886	0.719	20	58.93	40.66	0.19	0.22
2003	0.999	0.678	14	55.08	43.36	0.40	1.17

APPENDIX C. REFINED PM SPECIATION CALCULATIONS

ENTERGY ARKANSAS, INC.

WHITE BLUFF

DSI COST ESTIMATE BASIS DOCUMENT

SL-014000
Final, Rev. 1
April 5, 2018
Project 13027-002

Prepared by

Sargent & Lundy LLC

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CONTENTS

1. PURPOSE

Entergy has requested that Sargent & Lundy (S&L) evaluate installation of a new dry sorbent injection (DSI) system on the units at White Bluff to control sulfur dioxide (SO_2) emissions. The purpose of this document is to define the project scope and identify the assumptions that were used as the basis for the operating and maintenance (O&M) and the capital cost estimates.

2. TECHNOLOGY DESCRIPTION

DSI is a proven technology, which has only recently been implemented, for moderate removal of SO_2 and other acid gases from coal-fired power plants. It involves injection of sodium-based sorbents into the ductwork after the boiler and prior to the particulate collection device. DSI is a relatively low capital cost, moderate SO_2 removal alternative to wet or dry FGD systems. No slurry equipment or separate reactor vessel is required with a DSI system. With the proper temperature profile and stoichiometry, the sorbent can effectively react with $SO_2$and other acid gases in the flue gas. The resulting particulate matter is removed from the flue gas by a particulate collection device, typically an existing electrostatic precipitator (ESP).

The typical DSI sorbents include sodium bicarbonate ($NaHCO_3$) and Trona ($Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$). Sorbent injection into the ductwork (downstream of the boiler and upstream of the ESP) has been tested in the industry using sodium-based sorbents. The process works through neutralization of SO_2 and other acid gases with the caustic sorbent; the neutralization occurs as long as the sorbent remains in contact with the gas. Sorbent injection has been proven effective on a variety of pulverized coal-fired boilers using a range of low to high sulfur coals. It is considered a commercial technology although with a limited supplier base due to the historically limited interest.

The DSI process produces a dry byproduct which can be landfilled. The waste products will contain sodium sulfate and sulfite ($NaSO_3$/$NaSO_4$) along with the unused sorbent and the normal fly ash. These wastes will be collected in the ESP and can be transported with conventional pneumatic fly ash handling equipment. The waste from sodium-based sorbents will have relatively high concentrations of soluble salts, which may affect the byproduct handling. With the addition of dry sorbent byproducts fly ash cannot be sold for reuse.

3. APPROACH

The project capital and O&M cost estimates are based on project-specific information, including:

- An engineer-procure-construct (EPC) contracting strategy with the DSI technology supplier providing the main process equipment, including reagent storage, milling, conveyance, and injection lances.
- Reagent injection at the air preheater (APH) outlet, upstream of the existing ESP. The cost to rebuild/upgrade the ESP was included to ensure there is no increase in PM emissions as a significant quantity of reagent will be added upstream of the existing ESP.
- On-site disposal of DSI byproduct using upgraded ESP ash handling equipment. The byproduct will be collected in the existing ESP in conjunction with the fly ash from the units; no additional blending equipment is required.
- Reagent injection rates based on 50% SO_2 removal from a design inlet concentration of 0.76 lb SO_2/MMBtu, based on the highest 5% of SO_2 emissions from 2009 through 2013.
    - Annual operating costs will be based on 50% SO_2 removal from an uncontrolled SO_2 rate of 0.57 lb SO_2/MMBtu, based on the annual heat input weighted average emission from 2009 through 2013.
    - The system will be designed to control emissions to meet a permit limit of 0.35 lb/MMBtu on a 30-boiler day rolling average, based on a maximum 30-day average SO_2 emission rate of 0.66 lb/MMBtu from 2009 through 2013.
- Trona was used as the DSI reagent for the purposes of this estimate.
- Increase in carbon consumption by 1 lb/mmacf to mitigate any impacts on mercury performance associated with ACI/DSI interference and mitigate potential for a brown plume.
- A high level conceptual system design, based on the estimated injection rate, was used as input to the DSI cost estimate. The following were estimated based on previous projects and scaled for the predicted dry sorbent injection rate for White Bluff:
    - Auxiliary power consumption
    - Annual reagent consumption
    - Additional carbon consumption
    - Additional water consumption
    - Additional waste production
    - Reagent storage silos
    - Quantity of mills
    - Quantity of blower trains

The total plant capital cost estimate includes the following:

- Equipment and material
- Installation labor
- Indirect field costs
- Freight
- General and Administration
- Erection contractor profit
- Engineering, Procurement and Project Services
- Spare parts/initial fills (other than reagent)
- EPC Fee

As part of this project, S&L estimated the costs for Owner's services and costs outside of the EPC contract including the following:

- Owner's Costs
- Owner's Engineer
- Construction Management Support
- Startup and Commissioning Support
- Performance Testing
- Contingency
- Escalation
- Interest During Construction

Cost Estimate 34018A provided in Attachment 1 represents the total cost to Entergy to install DSI technology on a single unit at White Bluff (Unit 1 or 2) including the EPC Contract price and all additional Owner's costs and third party services.

The total unit O&M cost estimate includes the following:

- Waste disposal (DSI waste + increased carbon + unsold fly ash)
- Loss of revenue from fly ash sales
- Reagent consumption (including increased carbon consumption)
- Auxiliary power consumption
- Low quality water consumption for mill cleaning
- Operating labor
- Maintenance material
- Maintenance labor

The O&M Cost Estimate and Capital Cost Estimate 34018A were developed using the assumptions and scope provided in this document. The project definition and accuracy corresponds to a study level estimate as defined in U.S.EPA's Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual. The costs provided in this report are in 2016 dollars.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

4.1 DESIGN INPUTS AND ASSUMPTIONS

The following assumptions were made for the design basis for the White Bluff DSI Systems:

- Design SO_2 inlet concentration of 0.76 lb SO_2/MMBtu.
- SO_2 inlet concentration of 0.57 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 removal efficiency of 50% (defined by injection rate, described in Section 4.1.1)
- Annual capacity factor of 71.2% (annual average capacity factor for White Bluff Units 1 and 2 based on historical heat input from 2009 through 2013).
- Reagent injection at the APH outlet, upstream of the existing ESP.
- Reagent delivery by rail.
- Existing activated carbon silo storage time will be reduced, rather than adding additional or larger storage silos to the system.
- Compliance deadline of three years from the effective date of the rule.

Before proceeding with a DSI project, a demonstration test should be completed at White Bluff to confirm the feasibility of DSI technology at White Bluff and quantify the potential BOP impacts associated with the project, such as impacts to the ESP performance, interference with mercury control technologies, and leachability of the byproduct.

4.1.1 ESP/Ash Handling Modifications

The DSI system, as defined in this report would require an estimated Trona injection rate of approximately 22,000 lb/hour to achieve 50% reduction at the design SO_2 inlet concentration. This injection rate would result in an increase in the particulate loading to the ESP of almost 40% from the current ash loading, due to the DSI byproducts and unreacted DSI reagent.

The addition of sodium compounds to the fly ash lowers the overall resistivity of the particulate being captured as well as shifting the particle size distribution. These changes have been shown to improve the removal efficiency of an ESP; in some cases this increase has been shown to offset the increased particulate loading to the ESP.

ESP performance can also be negatively impacted by a significant increase in particulate loading associated with the high reagent injection rates required for SO_2 control. It is uncertain whether modifications to the ESPs and ash handling systems would be required to accommodate the addition of DSI at White Bluff. However, at the very high injection rates expected for this project, an ESP rebuild will likely be required to ensure the PM emissions stay below the PSD threshold. Therefore, the capital cost estimate includes the costs to completely rebuild the existing ESPs and ash handling systems at White Bluff.

The size and condition of the existing ESP can play a critical role in the overall performance of DSI. In order to evaluate the existing White Bluff ESP with respect to future operation with DSI, S&L used the EPA program ESPVI 4.0W Performance Prediction Model (ESPVI 4.0W) to simulate the baseline and future operating scenarios, as described below. In addition, S&L contacted an ESP vendor to provide input relating to installation of DSI upstream of the existing ESPs at White Bluff.

The baseline operation was established using various design inputs for the units (as needed by the ESPVI 4.0W model), recent operating data and stack emissions to estimate the efficiency at which the ESP is currently operating. ESPVI 4.0W showed that at the baseline operating conditions the White Bluff ESP operates at approximately 99.7% removal of the total inlet loading, corresponding to a filterable PM emission limit of 0.0155 lb/MMBtu.

ESPs operate at a constant efficiency assuming the operating conditions (such as temperature, ash resistivity, or flue gas velocity) stay the same. DSI can impact some of the operating conditions, specifically ash resistivity and particle size distribution. The addition of DSI thus could result in a higher efficiency than the same ESP, without DSI, could achieve.

The ESPVI 4.0W model was developed prior to the introduction of DSI technology and has not been updated to account for the impacts of adding sorbents upstream of the ESP. However, the model was used to predict the high level impact and/or limitations of installing DSI technology by modifying some of the inputs to simulate the characteristics of a fly ash/sodium sorbent mixture.

Based on the modified ash resistivity and adjusted particle sizes associated with the addition of DSI, the baseline ESPVI 4.0W model was used to estimate the predicted removal efficiency for the White Bluff ESP with DSI, as defined in this report, and assuming all other operating conditions remained the same. ESPVI 4.0W showed an overall removal efficiency which was very similar to the current ESP removal efficiency and resulted in an increase in particulate emissions with the additional loading from the DSI system.

Based on the results from ESPVI 4.0W, the White Bluff ESP may be operating at a marginally higher reduction efficiency with the installation of DSI; however, the loading to the ESP is also increasing significantly. Therefore, the modeling showed that even though the ESP efficiency may increase, the overall PM emissions will still be higher than the current level. This evaluation supports the conclusion that improvement of the existing ESP in conjunction with the DSI project is necessary to avoid increasing PM emissions.

In addition to the modeling that was performed using ESPVI 4.0W, S&L also engaged a vendor experienced with ESP retrofits to provide costs and expertise associated with injection of DSI on an existing ESP. As part of their budgetary quote, the supplier indicated that "while the ESPs are large they are still an efficiency machine and overcoming the new total inlet loading of over 73,000 lb/hr[1] will be extremely difficult to achieve the requested 0.015 lbs/MMBtu outlet PM emissions, without retrofitting the entire ESPs to BART technology. Essentially, the ESPs will need to be rebuilt to 'as-new' condition with the most state-of-the-art technology options" (see Attachment 2).

Finally, in addition to the performance of the ESP, the increased loading will also have an impact on the ash handling system. Therefore, for the purposes of this cost estimate, based on the significant increase in loading, modifications to the ash handling equipment were included in the cost estimate.

4.1.2 Landfill Modifications

The sodium byproducts (salts) that are produced when Trona reacts with SO_2 and other acid gases, along with the unreacted sorbent are soluble in water. The resulting waste collected in the particulate collection device will need to be disposed of in a landfill that is lined and has a leachate collection system. With the addition of DSI, White Bluff will no longer be able to sell their fly ash for beneficial re-use due to the solubility of the sodium salts which would be

[1] The 73,000 lb/hr loading reflects the design fly ash loading plus the additional loading from the DSI injection (byproduct/unreacted sorbent).

present in the waste. The cost to maintain a landfill and open new cells is included in the typical maintenance budget of a plant. It was assumed, that any future landfill cells would include lining and leachate collection; therefore, no landfill modifications will be required to accommodate the addition of DSI and no costs were included in this estimate.

4.2 TOTAL INSTALLED CAPITAL INVESTMENT

The DSI system supplier will provide all of the equipment related to storing, milling, conveying and injecting the reagent; in this case, the system is designed for Trona. The remaining BOP scope will be provided by the EPC Contractor. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DSI system supplier.

Quantities were developed based on limited project design effort, project experience of a plant of comparable size and then adjusted based on actual size and capacity differences and also taking into consideration the specific site layout based on the general arrangement. In most cases, the costs for bulk materials and equipment were derived from S&L database and recent vendor or manufacturer's quote for similar items on other projects. The scope of work for the capital cost estimate is broken out by the following areas:

4.2.1 DSI Area (Single Unit)

a. Reagent Storage Silos:
- Twelve silos capable of storing approximately 14 days of sorbent per unit, 4,200-tons storage total, including substructure
- 14' diameter and 125' high, each
- 350-tons working storage, each
- Continuous level detection systems
- One bin vent filter per silo
- Live bottom hopper outlets
- Rotary airlock assemblies

b. Reagent conveying systems:
- 4 trains (4 x 50%)
- Pneumatic pressure blowers (1 x100% per train)
- One dehumidifier and chiller per train

c. Reagent Milling
- One 7-tph mill per train
- One set of bypass piping per mill

d. Reagent Injection
- Splitters with piping to two APH outlets
- Six injection lances per injection location

e. Concrete foundations including piles for all reagent silo, blower, and mill areas; the approximate footprint for DSI Area is 165' x 125'

f. Buildings, enclosures, and roofs, including:
- Blower Building, approximately 25' x 100'
- Electrical Building; approximately 15' x 20'
- Mill Building; approximately 40 x 80'
- Dehumidifier Roof; approximately 30' x 125'
- Heat Exchanger Roof; approximately 10' x 80'

g. Geotechnical and subsurface investigation contractor work, including hydro excavation

h. Equipment pricing based on recent vendor pricing for a similar project.

4.2.2 Reagent Handling System

The conceptual design basis for the reagent handling system is to unload two cars at a time. Based on the estimated injection rate and typical railcar capacities, it is anticipated that approximately 20 railcars will be required each week per unit assuming a 100% capacity factor. The reagent handling system includes modification to the existing rail spur on-site to accommodate storage and handling of the reagent railcars. It was assumed that the reagent will be delivered via a 25-car unit train as a maximum. The following equipment and components are included in the cost estimate as part of the reagent handling system:

a. Reagent rail car unloader:
- System consists of mobile receiving pad and associated vacuum pneumatic connection equipment to unload railcar
- Enclosed railcar unloading building; approximately 200' x 75'
- Trackmobile used to haul and queue the rail cars before and after unloading; capable of moving approximately 25 cars at once.

b. Reagent unloading systems:
- Two trains (2 x 100%)
- Pneumatic pressure blowers (1 x 100%) per train
- One conveying air dehumidifier and chiller per train
- Pneumatic conveying piping located on an above-grade sleeper pipe rack
- The equipment pricing included in this estimate is based on recent firm pricing for similar projects. The basis of the conceptual design is a typical UCC arrangement and equipment.

c. Rail track spur extension to north to allow reagent train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs

4.2.3 ESP/Ash Handling Modifications

a. ESP Rebuild – Based on the budgetary quote provided in Attachment 2.

b. Ash Handling Modifications – Equipment pricing based on recent vendor pricing for a similar project.

4.2.4 Civil Work

a. Site grading

b. Soil removal earthwork

c. Excavation, backfill, and compaction for all foundations

d. Development of a new laydown area, approximately 2 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not require land to be purchased.

4.2.5 Mechanical Work

a. Allowance of $975,000 provided for mechanical system including transport piping, pipe rack, instrument/service air and other miscellaneous items based on recent in-house cost estimates for similar projects.

4.2.6 Demolition/Relocation

a. Allowance of $650,000 is provided for demolition and relocation of existing equipment and infrastructure which may interfere with the new DSI system based on recent in-house cost estimates for similar projects.

4.2.7 Electrical

a. Allowance of $3,575,000 is provided for electrical equipment upgrades and modifications based on recent in-house cost estimates for similar projects.

4.2.8 Instrumentation

a. Allowance of $520,000 provided for DCS upgrades and added instrumentation based on recent in-house cost estimates for similar projects.

4.2.9 Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

a. Labor Wage Rates

Crew labor rates were developed using prevailing craft rates and fringe benefits and state specific worker's compensation rates as published in the 2016 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. State specific workman's compensation rates are from R.S. Means. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

b. Labor crews

Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities; and include costs for small tools, construction equipment, insurance, and site overheads.

4.2.10 Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

a. Scaffolding and Consumables

b. Premiums and per diems ($10 per hour)

c. Overtime at five 10-hour shifts per week

d. Freight on construction materials

e. Contractor's General & Administration Fees (included at 10% of total direct costs)

f. Contractor's Profit (included at 5% of total direct costs)

g. Sales tax was included in the cost estimate at 8.125%.

Freight on the DSI System equipment was not included in the cost estimate.

4.2.11 EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $4,000,000.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of Trona was not included in the EPC Contractor's scope, as this will be supplied by the Owner and is covered as part of the Owner's Costs. The total cost of the initial fills was estimated to be $75,000.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 150 man-days. The estimate includes technical field advisors for the DSI system supplier (including DSI system subcontractors) and the DCS supplier. The total cost of the technical field advisors was estimated to be $300,000.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC risk fee is a premium charged by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor. Based on S&L's experience with recent EPC projects, an EPC risk fee was included at 10% of the total EPC project costs.

4.2.12 Owner's Costs and Services

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs.

a. Owner's Costs

Owner's Costs are direct costs that the Owner incurs over the life of the project. The following items are real costs Entergy will incur to install DSI at White Bluff based on the scope and schedule of this project:

- Internal Labor
- Internal Indirects
- Travel Expenses
- Legal Services
- Builders Risk Insurance
- Initial Fills (Reagent)

Owner's costs were included in the estimate at 8% of the total project cost.

b. Construction Management Support

The construction management support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The cost of labor is based on present day cost. The total cost of the construction management support was estimated to be $1,500,000.

c. Startup and Commissioning Support

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform the tasks, and therefore it will be outsourced. The total cost of the startup and commissioning support was estimated to be $300,000.

d. Owner's Engineer

The Owner's Engineer cost was developed as a high level estimate based on a typical scope for Owner's Engineer work for this type of project; including the following tasks:

- Conceptual Study Support
- EPC Specification Supporting Documents
- Project Schedule Development
- EPC Specification Development
- EPC Bid Evaluation and Contract Conformance
- General Project Support
    - Monthly Project Status Meetings
    - Weekly Teleconferences
    - Overall Coordination
    - Project Administration
    - Site Visits and Travel
- Permitting Support
- Design Review of Drawing Submittals
- Technical support during design, fabrication, construction, commissioning, and testing
- Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $1,750,000.

e. Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

- Development of the test protocol
- Procuring the services of the testing contractor
- Overseeing the performance test campaign
- Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days. The total cost of the Performance Testing was estimated to be $175,000.

f. Contingency

Contingency is included in the estimate to cover the uncertainty associated with the project costs. The cost estimate includes a recommended contingency of 25%, which is consistent with cost estimating guidelines for a conceptual design and the current level of project definition. Contingency was applied to the total project costs before escalation.

g. Escalation

Escalation was included in the estimate based on a typical schedule for implementation of a DSI system at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

h. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on a typical schedule for implementation of a DSI system and a typical interest rate of 7.8% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable O&M costs for each reagent specific system. All of these values, with the exception of the reagent costs, were provided by Entergy. The reagent costs are based on recent pricing received by S&L for another project.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Trona	$/ton	$205
Activated Carbon	$/ton	$1,700
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Fly Ash Revenue	$/ton	$5.85
Aux Power Cost [1]	$/MWh	$41.02

Note 1: Entergy provided auxiliary power costs for the first year of operation.

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for each case. The reagent consumption rate was developed using a normalized stoichiometric ratio (NSR) of 1.3 which is consistent with test data for similar projects.

Table 4-2: Variable O&M Rates and First Year Costs

	Units	Value
DSI System Parameters		
Reagent Consumption	lb/hr	16,500
Increased Carbon Consumption	lb/hr	210
DSI Waste Production + Increased Carbon + Unsold Fly Ash[3]	lb/hr	40,700
Aux Power Consumption	kW	1,700
Low Quality Water Consumption	gpm	4

	Units	Value
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$10,548,500
Waste Disposal Cost (DSI Waste + Increased Carbon + Unsold Fly Ash)	$/year	$951,900
Increased Carbon Consumption Cost	$/year	$1,113,000
Aux Power Cost	$/year	$434,900
Low Quality Water Cost	$/year	$800
Loss of Fly Ash Sales[3]	$/year	$496,000
Total First Year Variable O&M Cost	**$/year**	**$13,545,100**

Note 1: First year costs are provided in $2016.

Note 2: The first year costs are calculated using an annual capacity factor of 71.2%.

Note 3: Assumes 57% of the station's fly ash was being sold on an annual basis for an average of approximately $5.85 per ton (based on historical data from Entergy).

4.4 FIXED O&M COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). The recommended staffing additions for the DSI system are 9 personnel for one system.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 0.3% of the project capital. Items such as track work and civil work would be considered high capital cost items with little to no maintenance. Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs

First Year[1] Fixed O&M Costs	**Units**	**Value**
Operating Labor[2]	$/year	$1,066,000
Maintenance Material	$/year	$180,000
Maintenance Labor	$/year	$120,000
Total First Year Fixed O&M Cost	**$/year**	**$1,366,000**

Note 1: First year costs are provided in $2016.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on a single unit would require 9 operators total.

5. ATTACHMENTS

1. White Bluff Station DSI System EPC Conceptual Cost Estimate, Sargent & Lundy Estimate No. 34018A
2. ESP Rebuild Budgetary Quote

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Estimator	A. KOCI
Labor rate table	16ARPBL
Project No.	13027-004
Estimate Date	10/20/2016
Reviewed By	MNO
Approved By	MNO
Estimate No.	34018A
Cost index	ARPBL

ENTERGY ARKANSAS
WHITE BLUFF STATION UNITS 1 OR 2 (SINGLE UNIT)
DSI SYSTEM EPC

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
101	UNIT 1 OR 2 (SINGLE UNIT) DSI AREA	3,359,550	15,000,000	527,160	18,441	11,107,036	29,993,746
102	REAGENT HANDLING SYSTEM	1,505,400	1,360,000	1,218,523	26,487	1,956,963	6,040,885
103	ESP/ASH HANDLING MODIFICATIONS	50,000,000	1,050,000		9,885	680,982	51,730,982
104	EARTHWORK			79,496	2,169	183,755	263,251
105	UPGRADE PLANT ENTRANCE						
106	LAYDOWN AREAS			156,000	1,839	146,722	302,722
107	MECHANICAL MISCELLANEOUS	975,000					975,000
108	DEMOLITION / RELOCATION COSTS	650,000					650,000
109	ELECTRICAL	3,575,000					3,575,000
110	INSTRUMENTATION	520,000					520,000
	TOTAL DIRECT	60,584,950	17,410,000	1,981,179	58,822	14,075,457	94,051,586

Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	14,075,457		58,822
Material	1,981,179		
Subcontract	60,584,950		
Process Equipment	17,410,000		
	94,051,586	**94,051,586**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	985,000		
91-2 Cost Due To OT 5-10's	1,859,000		
91-4 Per Diem	588,000		
91-5 Consumables	141,414		
91-6 Freight on Material	99,000		
91-8 Sales Tax	2,384,000		
91-9 Contractors G&A	1,990,000		
91-10 Contractors Profit	994,000		
	9,040,414	**103,092,000**	
Indirect Costs:			
93-1 Engineering Services	4,000,000		
93-4 SU/S Parts/ Initial Fills	75,000		
93-5 Technical Field Advisors	300,000		
93-8 EPC Fee	10,747,000		
	15,122,000	**118,214,000**	
Escalation:			
96-1 Escalation on Material	137,000		
96-2 Escalation on Labor	1,693,000		
96-3 Escalation on Subcontract	5,238,000		
96-4 Escalation on Process Eq	926,000		
96-5 Escalation on Indirects	1,261,000		
	9,255,000	**127,469,000**	
Total EPC Cost		***127,469,000***	
Owner's Costs:			
99-1 Owner's Costs	9,457,000		
	9,457,000	**136,926,000**	
Third Party Services:			
100 CM Oversight	1,500,000		
101 Start-Up Oversight	300,000		
102 Owner's Engineer	1,750,000		
103 Performance Testing	175,000		
	3,725,000	**140,651,000**	
Project Contingency :			
110 Project Contingency	32,851,000		
	32,851,000	**173,502,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	960,000		
	960,000	**174,462,000**	
Interest During Construction:			
130 Interest During Constr.	15,649,000		
	15,649,000	**190,111,000**	
Total		***190,111,000***	

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
101			**UNIT 1 OR 2 (SINGLE UNIT) DSI AREA**									
	21.00.00		**CIVIL WORK**									
		21.53.00	**PILING**									
			AUGER CAST GROUT PILE, 18 IN DIA BY 80 FT LONG	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	323.00 EA	1,162,800	-	-		108.88 /MH		1,162,800
			PILE - MOB/DEMOB		1.00 LS	100,000	-			108.88 /MH		100,000
			PILING			**1,262,800**						**1,262,800**
		21.98.00	**CIVIL WORK,TESTING**									
			AUGER CAST GROUT PILE - TESTING		1.00 LS	65,000	-	-		-	-	65,000
			CIVIL WORK,TESTING			**65,000**						**65,000**
			CIVIL WORK			**1,327,800**						**1,327,800**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	DSI AREA FOUNDATIONS INCLUDING REAGENT SILOS	2,292.00 CY	-	-	527,160	18,441	60.03 /MH	1,107,036	1,634,196
			CONCRETE					**527,160**	**18,441**		**1,107,036**	**1,634,196**
			CONCRETE					**527,160**	**18,441**		**1,107,036**	**1,634,196**
	23.00.00		**STEEL**									
		23.25.00	**ROLLED SHAPE**									
			BUILDING MIX, TWO COAT PAINTED		TN	-	-			93.00 /MH		
	24.00.00		**ARCHITECTURAL**									
		24.35.00	**PRE-ENGINEERED BUILDING**									
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	BLOWER BUILDING 25 FT X 100 FT	2,500.00 SF	500,000	-			93.00 /MH		500,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	ELECTRICAL BUILDING 15 FT X 20 FT	300.00 SF	105,000	-			93.00 /MH		105,000
			SHELL INCLUDING ELECTRICAL & HVAC-STEEL INSULATED 22 GA	MILL BUILDING 40 FT X 80 FT	3,200.00 SF	640,000	-			93.00 /MH		640,000
			SHELL - ROOF ONLY AREA	DEHUMIDIFIER - 30 FT X 125 FT	3,750.00 SF	318,750	-			93.00 /MH		318,750
			SHELL - ROOF ONLY AREA	HEAT EXCHANGER - 10 FT X 80 FT	800.00 SF	68,000	-			93.00 /MH		68,000
			PRE-ENGINEERED BUILDING			**1,631,750**						**1,631,750**
		24.37.00	**ROOFING**									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	DSI AREA ENCLOSURE ROOF	SF	-	-			35.25 /MH		
		24.41.00	**SIDING**									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	DSI AREA ENCLOSURE SIDING	SF	-	-			79.98 /MH		
		24.99.00	**ARCHITECTURAL, MISCELLANEOUS**									
			HEATING	DSI AREA	SF	-	-			64.51 /MH		
			LIGHTING	DSI AREA	SF	-	-			82.56 /MH		
			FIRE PROTECTION	DSI AREA	SF	-	-			82.56 /MH		
			ARCHITECTURAL			**1,631,750**						**1,631,750**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.99.00	**MECHANICAL EQUIPMENT, MISCELLANEOUS**									
			DSI SYSTEM EQUIPMENT	EQUIPMENT COST FOR UNIT 1 OR 2 (SINGLE UNIT)	1.00 LS		15,000,000	-		/MH	10,000,000	25,000,000
			STORAGE SILOS WITH BIN VENT FILTERS (~14 DAYS STORAGE)	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			BLOWERS, HEAT EXCHANGERS, DEHUMIDIFIERS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MILLING EQUIPMENT	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			PIPING SYSTEMS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			COMPRESSORS	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			FLOW MODELING	INCLUDED ABOVE	1.00 LS		-	-		68.89 /MH		
			MECHANICAL EQUIPMENT, MISCELLANEOUS				**15,000,000**				**10,000,000**	**25,000,000**
			MECHANICAL EQUIPMENT				**15,000,000**				**10,000,000**	**25,000,000**
	71.00.00		**PROJECT INDIRECT**									
		71.25.00	**CONSULTANT, THIRD PARTY**									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	250,000	-			/MH		250,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CONSULTANT, THIRD PARTY			400,000						400,000
			PROJECT INDIRECT			400,000						400,000
			101 UNIT 1 OR 2 (SINGLE UNIT) DSI AREA			**3,359,550**	**15,000,000**	**527,160**	**18,441**		**11,107,036**	**29,993,746**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	EXTEND REAGENT RAIL TRACK	90,000.00 SF	-	-		207	182.87 /MH	37,835	37,835
			STRIP & STOCKPILE TOPSOIL						207		37,835	37,835
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	EXTEND REAGENT RAIL TRACK	10,000.00 SY	-	-	106,500	345	97.70 /MH	33,690	140,190
			EROSION AND SEDIMENTATION CONTROL					106,500	345		33,690	140,190
		21.53.00	PILING									
			AUGER CAST GROUT PILE, 18 IN DIA BY 80 FT LONG	UNLOADING SHED 200' X 75' WIDE	64.00 EA	230,400	-	-	0	108.88 /MH	1	230,401
			PILING			230,400			0		1	230,401
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	EXTEND REAGENT RAIL TRACK	4,500.00 TF	-	-	765,000	7,759	81.75 /MH	634,267	1,399,267
			TRACKWORK					765,000	7,759		634,267	1,399,267
			CIVIL WORK			230,400		871,500	8,310		705,793	1,807,693
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75' WIDE	926.00 CY	-	-	212,980	7,451	60.03 /MH	447,258	660,238
			CONCRETE					212,980	7,451		447,258	660,238
			CONCRETE					212,980	7,451		447,258	660,238
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75' WIDE x 20' TALL	15,000.00 SF	1,275,000	-			93.00 /MH		1,275,000
			PRE-ENGINEERED BUILDING			1,275,000						1,275,000
			ARCHITECTURAL			1,275,000						1,275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			REAGENT PNEUMATIC TRAIN UNLOADING EQUIPMENT		2.00 LS	-	1,000,000	-	6,611	68.89 /MH	455,466	1,455,466
			MATERIAL HANDLING EQUIPMENT				1,000,000		6,611		455,466	1,455,466
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.89 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER	IN UNLOADING SHED 200' X 75' WIDE	1.00 LT	-	135,000	-	1,862	93.00 /MH	173,172	308,172
			RAIL CAR UNLOADER				135,000		1,862		173,172	308,172
			MATERIAL HANDLING EQUIPMENT				1,360,000		8,474		628,638	1,988,638
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	250.00 LF	-	-	10,043	270	77.80 /MH	21,015	31,057
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	1,250.00 LF	-	-	124,000	1,983	77.80 /MH	154,259	278,259
			CARBON STEEL, STRAIGHT RUN					134,043	2,253		175,274	309,316
			PIPING					134,043	2,253		175,274	309,316
			102 REAGENT HANDLING SYSTEM			**1,505,400**	**1,360,000**	**1,218,523**	**26,487**		**1,956,963**	**6,040,885**
103			**ESP/ASH HANDLING MODIFICATIONS**									
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS									
			ESP EQUIPMENT MODIFICATION	FULL REBUILD OF ESP, INCLUDING INSTALLATION COST	1.00 LS	50,000,000	-	-		68.89 /MH		50,000,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		33.99.00	MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS									
			ASH HANDLING COMPONENT MODIFICATION	ALLOWANCE	1.00 LS		1,050,000	-	9,885	68.89 /MH	680,982	1,730,982
			MATERIAL HANDLING EQUIPMENT, MISCELLANEOUS			50,000,000	1,050,000		9,885		680,982	51,730,982
			MATERIAL HANDLING EQUIPMENT			50,000,000	1,050,000		9,885		680,982	51,730,982
			103 ESP/ASH HANDLING MODIFICATIONS			**50,000,000**	**1,050,000**		**9,885**		**680,982**	**51,730,982**
104			**EARTHWORK**									
	21.00.00		CIVIL WORK									
		21.14.00	STRIP & STOCKPILE TOPSOIL									
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING ALLOWANCE	30,000.00 SF	-	-		69	182.87 /MH	12,612	12,612
			STRIP & STOCKPILE TOPSOIL - ONSITE	BUILDINGS	600.00 CY	-	-		79	182.87 /MH	14,503	14,503
			STRIP & STOCKPILE TOPSOIL						148		27,115	27,115
		21.17.00	EXCAVATION									
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS	BUILDINGS	2,860.00 CY	-	-		986	79.78 /MH	78,680	78,680
			EXCAVATION						986		78,680	78,680
		21.39.00	STORM DRAINAGE UTILITIES									
			STORM SEWER WORK	SITE GRADING ALLOWANCE	1.00 LT	-	-	44,000	920	72.57 /MH	66,731	110,731
			STORM DRAINAGE UTILITIES					44,000	920		66,731	110,731
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING ALLOWANCE	3,333.00 SY	-	-	35,496	115	97.70 /MH	11,229	46,725
			EROSION AND SEDIMENTATION CONTROL					35,496	115		11,229	46,725
			CIVIL WORK					79,496	2,169		183,755	263,251
			104 EARTHWORK					**79,496**	**2,169**		**183,755**	**263,251**
105			**UPGRADE PLANT ENTRANCE**									
	21.00.00		CIVIL WORK									
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			UPGRADE PLANT ENTRANCE	WORK NOT REQUIRED	0.00 LF	-	-			78.79 /MH		
106			**LAYDOWN AREAS**									
	21.00.00		CIVIL WORK									
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	2.00 AC	-	-	156,000	1,839	79.78 /MH	146,722	302,722
			CIVIL WORK, MISCELLANEOUS					156,000	1,839		146,722	302,722
			CIVIL WORK					156,000	1,839		146,722	302,722
			106 LAYDOWN AREAS					**156,000**	**1,839**		**146,722**	**302,722**
107			**MECHANICAL MISCELLANEOUS**									
	31.00.00		MECHANICAL EQUIPMENT									
		31.99.00	MECHANICAL EQUIPMENT, MISCELLANEOUS									
			MECHANICAL EQUIPMENT	INCLUDES PIPE RACK - ALLOWANCE SUBCONTRACT COST	1.00 LS	975,000	-	-		68.89 /MH		975,000
			MECHANICAL EQUIPMENT, MISCELLANEOUS			975,000						975,000
			MECHANICAL EQUIPMENT			975,000						975,000
			107 MECHANICAL MISCELLANEOUS			**975,000**						**975,000**
108			**DEMOLITION / RELOCATION COSTS**									
	11.00.00		DEMOLITION									
		11.99.00	DEMOLITION, MISCELLANEOUS									
			DEMOLITION AND RELOCATION	ALLOWANCE - SUBCONTRACT COST	1.00 LS	650,000	-			107.47 /MH		650,000
			DEMOLITION, MISCELLANEOUS			650,000						650,000
			DEMOLITION			650,000						650,000
			108 DEMOLITION / RELOCATION COSTS			**650,000**						**650,000**
109			**ELECTRICAL**									
	41.00.00		ELECTRICAL EQUIPMENT									
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS	ALLOWANCE - SUBCONTRACT COST	1.00 LS	3,575,000	-			64.04 /MH		3,575,000
			ELECTRICAL EQUIPMENT, MISCELLANEOUS			3,575,000						3,575,000
			ELECTRICAL EQUIPMENT			3,575,000						3,575,000
			109 ELECTRICAL			3,575,000						3,575,000
110			INSTRUMENTATION									
	44.00.00		CONTROL & INSTRUMENTATION									
		44.99.00	CONTROL & INSTRUMENTATION, ALLOWANCE									
			CONTROL & INSTRUMENTATION	ALLOWANCE - SUBCONTRACT COST	1.00 LS	520,000	-			65.15 /MH		520,000
			CONTROL & INSTRUMENTATION, ALLOWANCE			520,000						520,000
			CONTROL & INSTRUMENTATION			520,000						520,000
			110 INSTRUMENTATION			520,000						520,000

27881 Clemens Road
Westlake, OH 44145
Phone: 440.899.3888
Fax: 440.899.3890

October 17, 2016

Sargent & Lundy
Attention: Danielle Flagg
55 East Monroe Street
Chicago, IL 60603

Subject: Fuel Tech, Inc. (FTI) Estimate #16-B-111 Rev1
Confidential Client ESP Retrofit
High Level Estimate

Dear Ms. Flagg,

In response to Sargent & Lundy's (S&L)'s recent request, Fuel Tech, Inc. (FTI), has assembled a high level estimate for the materials and installation necessary to retrofit Sargent & Lundy's "Confidential Client" Electrostatic Precipitators. Please consider the pricing as +/- 30% for high level budgetary estimation purposes.

The ESPs have been evaluated by our engineering staff and the estimate includes the most comprehensive improvements possible. Improvements that we have included in the estimate to increase performance and reliability include all new internals; collecting plates at 16" wide plate spacing, rigid discharge electrodes, top-rapped MIGI rapper conversion with increased rapping sectionalization, increased high voltage frame electrical sectionalization, and the addition of high frequency power supplies.

The estimates and information provided above are based upon FTI's historical information and experience, and should be used for accounting purposes ONLY. Should S&L want to move forward with a more in-depth budgetary proposal, FTI can provide such a document with additional lead-time. Thank you for your interest in our products and services, and we will continue to support Sargent & Lundy's efforts in any way practical for this and other opportunities. Should you require any additional information regarding this submittal, please contact me directly.

Respectfully,

Dustin Ekey
Regional Sales Manager

FTI Budgetary Proposal #16-B-111
Rev 1

Sargent & Lundy
Confidential Client ESP Retrofit

Submitted by:

27881 Clemens Road
Westlake, Ohio 44145
P: 440.539.8792
www.ftek.com

EXECUTIVE SUMMARY

Sargent & Lundy – Confidential Client ESP Rebuild Budgetary Request:

In accordance with Sargent & Lundy's RFQ dated September 30, 2016, Fuel Tech, Inc. (FTI) has provided a high level estimate based on historical data to engineer, design, supply, and deliver an ESP Retrofit based on the provided information as follows;

A confidential client is currently evaluating the costs associated with rebuilding an existing ESP. As part of this project, the client will potentially be installing dry sorbent injection (DSI) upstream of the upgraded ESP.

The following summarizes the ESP design of the unit being evaluated:

- PC Walther original OEM installed in the early 1980s.
- Consists of four (4) identical ESP casings, with two (2) casings on top of the other two (2) casings; AKA "Piggybacked".
- Each ESP casing has eight (8) mechanical fields, two (2) mechanical fields wide by four (4) mechanical fields deep.
- Each field is 14' in length and contains forty-four (44) collecting electrodes with forty-three (43) gas passages.
- The collecting electrodes are 48' in height with 12" plate spacing.
- The total collecting surface area is 1,900,000 ft^2.
- Design flue gas flowrate is approximately 3,500,000 acfm, and a design velocity of 5 feet per second.
- The SCA of the existing ESP is approximately 540 ft^2/MMacfm.
- The overall dimension for each ESP is approximately 85'L x 90'W x 50'H.
- Each gas passage has discharge frame electrodes.
- The system is equipped with a Walther tumbling hammer rapper system.
- There are eight (8) T/R sets on each ESP, with a total of thirty-two (32).

ESP rebuild design and performance considerations:

- Achieve an outlet PM emissions rate of 0.015 lb/MMBtu or lower.
- Design inlet ash loading of 55,000 lb/hr.
- Non-halogenated PAC is injected at 150 lb/hr.
- Trona will be injected at 22,500 lb/hr, resulting in an increased particulate loading of 18,200 lb/hr to the ESP.
- Inlet flue gas temperature up to 315 deg F.

<u>Fuel Tech, Inc. – Retrofitted ESP Arrangement and Summary:</u>

While the existing ESPs are considered to be relatively large by industry standards, the design information provided shows that 22,500 lb/hr of Trona will be injected in addition to the existing inlet ash loading is 55,000 lb/hr. With this being said, while the ESPs are large they are still an efficiency machine and overcoming the new total inlet loading of over 73,000 lb/hr will be extremely difficult to achieve the requested 0.015 lbs/MMbtu outlet PM emissions, without retrofitting the entire ESPs to BART technology. Essentially, the ESPs will need to be rebuilt to “as-new” condition with the most state-of-the-art technology options. At the very least, new internals and electrical control systems would require new:

- Assembled Panel Collecting Electrodes
- Rigid Discharge Electrodes
- Top-Rapped MIGI Style Rapper Conversion
- All new Hot Roof, Cold Roof, and Penthouse
- Heated Purge Air Systems
- High Frequency Switch-Mode Power Supplies (SMPS)
- New Access Doors
- All new 3-Phase Electrical Supply Wiring
- New Controllers
- New Hopper Arrangement

<u>Retrofit ESP Arrangement; Quantities are for one (1) ESP, there are four (4) ESPs total:</u>

Number of ESP’s / Unit:	4
Mechanical Fields & Size / ESP:	6 @ 9’
Electrical Fields & Size / ESP:	12 @ 4.5’
Chambers / ESP:	2
Gas Passages / Chamber:	33
Collecting Plates / Chamber:	32
Collecting Plate Height:	44’
Plate Spacing:	16”
RDE’s / ESP:	1,536
Rapping Arrangment:	Top Rapped – MIGI
Collecting System Rappers / ESP:	176
Discharge System Rappers / ESP:	48
High Frequency Power Supplies / ESP:	16

The amount of planning, engineering, material supply, installation, and installation oversight necessary for a project listed above will be very significant. Pricing estimation can be found below.

High-Level Pricing Estimation for one (1) Confidential Unit including all four (4) ESPs:

Pricing estimate is based upon +/- 30%

The total budgetary estimate to provide ESP materials and engineering: **$ 20,000,000.00**

The total budgetary estimate to provide non-union installation: **$ 30,000,000.00**

*Note: The estimates and information provided above are based upon FTI's historical information and experience, and should be used for accounting purposes ONLY. Should S&L want to move forward with a more in-depth budgetary proposal, FTI can provide such a document with additional lead-time.

Entergy Arkansas Inc.

Comments

On the Proposed Regional Haze and Interstate Visibility Transport

Federal Implementation Plan for Arkansas

Docket No. EPA-R06-OAR-2015-0189

Submitted on:
August 7, 2015

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

Via:
http://www.regulations.gov
Docket ID No. EPA-R06-OAR-2015-0189

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EXHIBITS

A. *Review of EPA's Cost Analysis for Arkansas Regional Haze Proposed Federal Implementation Plan*, Report No. SL-012913, Sargent & Lundy (July 2015).

B. *White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831, Sargent & Lundy (July 2015).

C. *Regional Haze Modeling Assessment Report, Entergy Arkansas, Inc. - Independence Plant*, Trinity Consultants (August 4, 2015).

D. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015).

E. *Just-Noticeable Differences in Atmospheric Haze*, Ronald C. Henry, Department of Civil and Environmental Engineering, University of Southern California, Los Angeles, Air & Waste Management Association (2002).

F. Excerpts from *Tangential Low NOx (TLN3) System for Entergy White Bluff Units 1 & 2*, Foster Wheeler North America Corp. Proposal to Entergy (Oct. 13, 2011).

G. Memorandum from Steve deMello, Project Manager, Amec Foster Wheeler North America Corp., to Michael P. Fallon, P.E., Entergy (July 30, 2015).

H. *Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. - Lake Catherine Plant*, Trinity Consultants (Aug. 4, 2015).

I. Entergy Arkansas Inc.'s Comments on the Proposed Approval and Promulgation of Implementation Plans; Interstate Transport State Implementation Plan; Arkansas, Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility, Docket No. EPA-R06-OAR-2008-0633.

ENTERGY ARKANSAS INC.
COMMENTS ON THE PROPOSED REGIONAL HAZE
AND INTERSTATE VISIBILITY TRANSPORT
FEDERAL IMPLEMENTATION PLAN FOR ARKANSAS

EPA-R06-OAR-2015-0189

I. INTRODUCTION

On April 8, 2015, the U. S. Environmental Protection Agency ("EPA" or "Agency") published in the *Federal Register*, at 80 Fed. Reg. 18,944, a proposed Federal Implementation Plan ("FIP") to address certain regional haze and visibility transport requirements for the State of Arkansas ("Proposed FIP" or "Proposal"). The Proposed FIP would address the requirements of the Regional Haze Rule and interstate visibility transport for those portions of Arkansas' State Implementation Plan ("SIP") that EPA previously had disapproved. *See* 77 Fed. Reg. 14,604 (Mar. 12, 2012). The Proposed FIP addresses the requirements for Best Available Retrofit Technology ("BART") for those sources for which EPA did not approve Arkansas' BART determinations, Reasonable Progress Goals ("RPGs"), reasonable progress controls and a long-term strategy, as well as the interstate visibility transport requirements for pollutants that affect visibility in Class I areas in nearby states.

Entergy Arkansas Inc. ("EAI" or "Entergy") owns and operates three facilities that EPA proposes to regulate under the FIP: White Bluff Electric Power Plant ("White Bluff"); Independence Steam Electric Station ("Independence"); and Lake Catherine Plant ("Lake Catherine"). EPA is proposing sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") BART limits for White Bluff Units 1 and 2, and SO_2, NOx, and particulate matter ("PM") BART limits for the Auxiliary Boiler at White Bluff. EPA also is proposing a NOx BART limit for Unit 4 at Lake Catherine. Finally, EPA is proposing emissions limits at Independence to meet reasonable progress requirements and is seeking comment on two alternative options. Under Option 1, EPA is proposing SO_2 and NOx emission limits for Units 1 and 2 at Independence. Under Option 2, EPA is proposing only SO_2 emission limits for Units 1 and 2. EPA also is soliciting comment on any alternative control measures for White Bluff Units 1 and 2 and Independence Units 1 and 2 that would address the BART and reasonable progress requirements for these four units for the current regional haze planning period.

In these comments, Entergy discusses its legal and technical concerns with the Proposed FIP. Entergy appreciates EPA's consideration of these comments, and urges EPA to make Entergy's suggested changes and issue a final FIP that provides visibility benefits without overly burdening EAI's customers and co-owners.

II. EXECUTIVE SUMMARY

The Regional Haze Program is intended to achieve gradual and steady improvement in visibility at Class I areas over the course of 64 years. The program was established under the Clean Air Act ("CAA") as a long-term program to allow major emitting sources to install controls or be phased out in a rational and economical manner to ultimately achieve natural visibility conditions at all Class I areas in the United States. The program also is intended to recognize that regional haze is a *regional* problem; one that benefits from broad programmatic changes and the retirement of sources as they reach the end of their useful lives. EPA's Proposed FIP for Arkansas largely abandons this approach, ignores the significant improvements in visibility in Arkansas' Class I areas that already have occurred, fails to account for the improvements that are anticipated to occur based on other regulatory programs, and seeks to impose more than $2 billion in costs on EAI's customers and co-owners despite the lack of any need for, or benefit from, such a massive investment.

Entergy proposes a more reasonable, long-term, multi-unit approach to address regional haze in the Arkansas Class I areas that achieves reasonable progress, is consistent with the statutory scheme and allows Entergy to manage its generation fleet in a reliable and economic manner. In particular, Entergy proposes the following: (1) to achieve early SO_2 reductions by accepting lower SO_2 emission rate limitations at both White Bluff and Independence; (2) to achieve NOx reductions by installing NOx control technology on all four units within three years of the final FIP's effective date; and (3) to commit to the permanent cessation of coal-fired operations at White Bluff by 2028. Based on modeling by Entergy (which EPA should have conducted but failed to undertake), the difference in visibility at the Arkansas Class I areas between the proposed FIP controls and Entergy's proposal is imperceptibly small (*see* Section III.D.2 below) and does not warrant an investment of over $2 billion in scrubber technology at the plants.

Entergy's comments address a range of issues raised by the Proposal. Two issues are most critical. First, with respect to White Bluff, Entergy proposes to cease all coal-fired operations at the two coal-fired units in 2027 and 2028. This proposal necessarily changes the BART analysis for White Bluff. Because of Entergy's proposed commitment to stop burning coal, EPA's proposal to establish BART limits for White Bluff based on the installation of dry flue gas desulfurization ("FGD" or "scrubbers") must be rejected. Under the current schedule for finalizing the FIP, the scrubbers would not be installed until at least 2021, which would leave only six to seven years for EAI to recoup the approximately $1 billion in investment for dry scrubber installation. That cannot be justified economically or environmentally. Economically, the short amortization period would drive the costs of the scrubbers to over $7,500-$8,500 per ton of SO_2 removed. Environmentally, EPA projects that visibility will improve in each of Arkansas' Class I areas only by approximately one-fifth of a deciview ("dv") as a result of the proposed FIP controls on all sources in Arkansas; an amount that is absolutely undetectable. Controls on White Bluff would achieve merely a fraction of that amount.

Second, EPA's proposal to require SO_2 and NOx limits based on the installation of dry scrubbers and NOx controls on the two coal-fired units at Independence cannot be justified for the first planning period. Independence is not a BART-eligible source.[1] Accordingly, EPA may impose emission reduction requirements on Independence under the Regional Haze Program *only* to the extent *necessary* to achieve reasonable progress towards natural visibility levels. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits ... as may be *necessary* to make reasonable progress") (emphasis added). The visibility in Arkansas' Class I

[1] Despite the fact that Independence is not a BART-eligible source under the Clean Air Act, EPA's analysis in the Proposal essentially and improperly treated it as such.

areas already has improved substantially in the past 10 years such that the haze index for both Class I areas currently is well below the uniform rate of progress ("URP" or "glide path") that EPA uses to ensure reasonable progress towards natural visibility conditions and that EPA had previously approved for Arkansas.[2] Based on the negligible visibility benefit from installing scrubbers at Independence, the cost of the controls is an astounding $1.33 billion to $1.53 billion per deciview improvement. *See* Section III.C.3 below. Scrubbers at Independence are simply not necessary to ensure that visibility in Arkansas' Class I areas remains below the URP, nor are they justifiable based on EPA's own analysis of the visibility benefits resulting from such a huge investment.[3]

Arkansas' Class I areas, the Caney Creek Wilderness Area ("Caney Creek") and the Upper Buffalo Wilderness Area ("Upper Buffalo"), have seen marked improvement in visibility since the start of regional haze monitoring. Based on the Interagency Monitoring of Protected Visual Environment ("IMPROVE") data, which reflects monitored visibility impairment in Class I areas, the haze index for the 20% worst ("W20") days of visibility has been steadily improving as a result of reduced emissions within Arkansas and because of broader industrial and energy trends in other states. According to modeling performed by the Central Regional Air Planning Association ("CENRAP"),[4] all of Arkansas' elevated point sources (including all power plants and large industrial sources) account for only about 2.7% and 2.3% of total light extinction within Caney Creek and Upper Buffalo, respectively. The overwhelming visibility impact comes from non-Arkansas point sources and mobile sources. Because of the Mercury and Air Toxic Standards ("MATS") rule,[5] the continuing benefits of the Clean Air Interstate Rule ("CAIR"), the next phase of the Cross State Air Pollution Rule ("CSAPR"), and implementation of the soon-to-be-released revised 8-hour ozone National Ambient Air Quality Standards ("NAAQS"), along with continuing reductions in emissions from mobile sources, the visibility at Caney Creek and Upper Buffalo will continue to improve. Based on the visibility trends in both Class I areas, the imposition of BART controls, and Entergy's proposed interim controls and proposed commitment to cease coal burning at White Bluff, no further action will be necessary to ensure that Arkansas' Class I areas remain below the URP until at least 2028 and likely even longer as a result of emissions controls that will be required by future regulatory programs and planned retirements of numerous electric generating units.

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[2] 76 Fed. Reg. 64,186, 64,194-95 (Oct. 17, 2011).

[3] The Class I areas outside of Arkansas that are potentially affected by emissions from Arkansas, similarly, are below the URP and do not need additional reductions to achieve reasonable progress or their long-term visibility goals.

[4] CENRAP is a regional planning organization that includes nine states – Nebraska, Kansas, Oklahoma, Texas, Minnesota, Iowa, Missouri, Arkansas, and Louisiana. Five such regional organizations are funded by EPA to address the interstate transport nature of the regional haze pollutants. The primary objective of these organizations is to evaluate technical information to better understand the impact of the affiliated states on national strategy and to develop regional strategies to reduce emissions of particulate matter and other pollutants leading to regional haze.

[5] In spite of the Supreme Court decision in *Michigan v. EPA*, 135 S.Ct. 2699 (2015), which held that EPA must evaluate costs in determining whether it is appropriate and necessary to regulate hazardous air pollutant emissions from electric generating units ("EGUs"), several EGUs already have installed controls to comply with MATS or have undertaken other steps to reduce their emissions. Even if the rule is stayed or vacated while EPA undertakes its cost analysis, Entergy expects that the rule will go forward before the end of this planning period along with the associated emission reductions.

EPA acknowledges that controls on Independence are not needed for Arkansas to achieve the URP. 80 Fed. Reg. at 18,992 ("We believe it is appropriate to evaluate Entergy Independence even though Arkansas Class I areas and those outside Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period."). Indeed, after the proposed BART controls are installed and White Bluff ceases coal-fired operations, Arkansas sources will not approach the URP, or glide path, for at least another decade. Entergy's analysis, based on the actual visibility impairment data, shows that Caney Creek will remain below the glide path until at least 2032 and Upper Buffalo until at least 2028 with no additional controls on in-state sources. *See* Section III.D.2 below (Figures 13 and 14). Imposing controls on Independence is simply not necessary or justified to achieve reasonable progress towards natural visibility in Arkansas' Class I areas.

EPA's reasonable progress analysis and justification for proposing stringent emission limitations at Independence are not legally defensible under the Regional Haze Program based on the costs and lack of visibility benefits of the proposed limits. EPA suggests it is only logical to require Independence to install controls because its SO_2 emissions are large and because it would be cost effective to control them. Cost effectiveness is a factor in deciding the degree of controls necessary to establish RPGs, but it is not an independent basis for imposing controls and does not determine reasonable progress goals. In this case, installing the controls on Independence that would be necessary to meet the proposed emission limits will cost EAI's customers and co-owners in excess of $1 billion. While the cost per ton of SO_2 removed may be within the range that might support a BART determination, it is nonetheless high in the context of reasonable progress controls, particularly where the benefits are small and reductions are not needed to demonstrate that Arkansas is making reasonable progress towards achieving natural visibility conditions at its Class I areas. Accordingly, Entergy objects to the RPGs that EPA is proposing for Arkansas.

EPA also improperly relied on CALPUFF modeling to justify the proposed controls at Independence, vastly overstating the impact of emissions from Independence and the benefits of installing controls. CALPUFF modeling, a single source puff model, is not an appropriate model to determine or project reasonable progress benefits. Reasonable progress is determined by evaluating the overall visibility values in Class I areas and the projected trends in visibility as a result of emissions, controls and operations at all sources contributing to visibility impairment. EPA has recognized in recent rulemakings that CALPUFF cannot do this and it is therefore arbitrary and capricious for EPA to rely on CALPUFF for this purpose here.

Entergy is prepared to offer meaningful interim emission reductions to complement its proposed commitment to cease coal-fired operations at White Bluff and assure that Arkansas remains on a path that is below the URP for the long term. Entergy proposes to meet more stringent SO_2 limits at both White Bluff and Independence beginning in 2018. In addition, Entergy proposes to install low NOx burners ("LNB") and separated overfire air ("SOFA") on both White Bluff and Independence within three years of the final FIP's effective date, assuring that there will be both near-term and long-term visibility benefits.

III. COMMENTS

A. Entergy Proposes To Cease Coal-Fired Operations At White Bluff By 2028 As Part Of A Long-Term, Multi-Unit Regional Haze Plan.

EPA's proposed BART determination for White Bluff appears to be based, in general, on the White Bluff five-factor BART analysis that Entergy provided to the Arkansas Department of Environmental Quality ("ADEQ") in October 2013 ("Revised White Bluff BART Analysis"),[6] which assumed White Bluff Units 1 and 2 would continue to combust coal for the foreseeable future. As part of a multi-unit plan to improve visibility and to better manage its generation assets for reliability and costs, Entergy proposes to cease burning coal at White Bluff Units 1 and 2 by 2027 and 2028, one unit per year, and is prepared to take an enforceable commitment to that effect.[7]

As a result of Entergy's proposal, EPA's proposed BART determination for White Bluff Units 1 and 2 has been rendered inapplicable. Entergy's proposal for White Bluff requires EPA to undertake a new BART analysis to address the remaining useful coal-fired life of the units. In addition, EPA used outdated costs in its BART analysis, improperly eliminated millions of dollars in costs necessary to install controls on White Bluff, and did not consider site-specific factors that will affect the cost calculation. When the appropriate dry scrubber costs are considered along with the units' remaining useful coal-fired life, the average cost effectiveness of dry FGD increases to a range of over $7,500 to $8,500 per ton at the White Bluff units, costs that are far too high to constitute BART.

1. EPA must take the remaining useful life of the White Bluff units into account in the BART analysis.

The CAA and EPA regulations dictate that EPA and states consider the remaining useful life of a source in BART determinations, which factors into the cost of compliance in the BART analysis. 42 U.S.C. § 7491(g)(2); 40 C.F.R. § 51.308(e)(1)(ii)(A). EPA's guidance provides a specific time period for amortization of the costs of controls where a unit's remaining useful life is limited.

> If the remaining useful life exceeds the amortization period, then the remaining useful life has essentially no effect on the control costs and on the BART determination process. Where the remaining useful life is less than the time period for amortizing costs, [EPA advises] us[ing] this shorter time period in [the BART] cost calculations.

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[6] Revised BART Five Factor Analysis, White Bluff Steam Electric Station (Oct. 2013), EPA Docket ID EPA-R06-OAR-2015-0189-0045. *See* 80 Fed. Reg. at 18,969-75. However, Entergy is confused by EPA's references in the Proposal to AEP's modeling and assumptions with respect to the BART analysis for White Bluff. *See id.* at 18,969. The references to AEP make it unclear whether EPA actually used Entergy's Revised White Bluff BART Analysis in evaluating the BART controls for White Bluff. EPA needs to confirm that it reviewed and analyzed Entergy's Revised White Bluff BART Analysis.

[7] Entergy anticipates that its compliance with a final FIP, including installing dry scrubbers or, in the alternative, ceasing coal-fired operation at White Bluff, will be subject to Arkansas Public Service Commission hearing and review.

Guidelines for BART Determinations Under the Regional Haze Rule, 40 C.F.R. Part 51, App. Y, Section IV.D.4.k ("BART Guidelines").

BART controls that may be cost effective using the standard amortization period (typically 20-30 years) may no longer be cost effective when a source's remaining useful life is factored into the analysis. *See* 79 Fed. Reg. 74,818, 74,837 (Dec. 16, 2014) ("Proposed Texas Regional Haze FIP") ("[CENRAP] noted that for sources with a relatively short remaining useful life, this consideration would have weighed more heavily against a determination that controlling those sources would have been reasonable.").

EPA determined that remaining useful life was not a meaningful factor for White Bluff given Entergy's previous plans to continue coal-fired operation at White Bluff. *See* 80 Fed. Reg. at 18,971, Tables 34 and 35 (using 30 years and the life of the equipment); Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plan (SO_2 Cost TSD), at 16 ("we typically assume a 30 year equipment life for scrubbers, as we do here."). As a result, EPA concluded that dry scrubbers on White Bluff would have an average cost effectiveness at Unit 1 of \$2,227/ton and at Unit 2 of \$2,101/ton. 80 Fed. Reg. at 18,971, Table 32. These cost estimates were based on a 30-year amortization period for the controls, an amortization period that is consistent with EPA's Control Cost Manual when a unit's remaining useful life is not limited. *EPA Air Pollution Control Cost Manual* (Jan. 2002) ("Control Cost Manual").[8]

Now, however, given Entergy's proposed commitment to cease coal-fired operation at White Bluff by 2027-2028, EPA will need to revise its BART analysis to take the remaining useful life of the units into account. The CAA requires that BART controls be installed "as expeditiously as practicable," but no later than five years from approval of a regional haze SIP or the issuance of a FIP. 42 U.S.C. § 7491(b)(2)(A), (g)(4); 40 C.F.R. § 51.308(e)(1)(iv). In this case, EPA has stated that it is unable to finalize the FIP until after December 15, 2015,[9] which means that any final FIP cannot have an effective date earlier than sometime in 2016. Thus, the scrubbers would be installed and operational, at the earliest, in 2021.[10] In light of Entergy's proposed commitment to cease coal-fired operations at the units in 2027 and 2028, the amortization period will be approximately six to seven years. This has a significant impact on the cost calculation, resulting in much higher costs compared to the emissions reductions achieved.

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[8] The Control Cost Manual is available at http://www.epa.gov/ttncatc1/dir1/c_allchs.pdf

[9] EPA's Response to Letter/Order (Dkt. No. 52) at 2, *Sierra Club v. McCarthy*, No. 14-cv-00643 (Jul. 15, 2015 E.D.Ark.).

[10] EPA has proposed to allow White Bluff the full five years to install the scrubbers and meet the BART SO_2 emission limits. 80 Fed. Reg. at 18,973. Entergy agrees with EPA that such major emissions control technology could not be designed, contracted for, and installed any earlier than five years from the effective date of the final regional haze FIP.

2. EPA's analysis of the costs to install dry scrubbers at White Bluff is replete with errors and artificially improves the cost effectiveness of scrubber installation at White Bluff.

EPA's analysis of the cost and cost effectiveness of installing dry scrubbers at White Bluff contains numerous flawed methodologies, incorrect assumptions and mistakes, all of which seem designed to artificially lower the actual costs of installing dry scrubbers and improve the supposed cost effectiveness of the controls. Sargent & Lundy ("S&L") has undertaken a thorough analysis of EPA's SO_2 Cost TSD and provided a report, *Report of EPA's Cost Analysis Arkansas Regional Haze Proposed Federal Implementation Plan*, No. SL-012913, Sargent & Lundy (July 2015) ("S&L FIP Cost Report") (attached as Exhibit A and incorporated by reference herein). The S&L FIP Cost Report demonstrates that EPA incorrectly specified the SO_2 emissions baseline for White Bluff, which increased expected emissions. EPA then improperly used maximum monthly emissions to estimate the tonnage reduction achievable with the scrubbers to reduce the cost per ton, and incorrectly eliminated approximately $100 million in costs that EPA's own Control Cost Manual says should be included.

(i) EPA arbitrarily eliminated two of five years in calculating baseline emissions for White Bluff.

The BART Guidelines state that baseline emissions from existing sources "should represent a realistic depiction of anticipated annual emissions for the source." 40 C.F.R. Part 51, App. Y, Section IV.D.4.d.1. In general, for the existing sources, facilities should estimate the anticipated annual emissions based upon actual emissions from a baseline period. Entergy originally had used the 2001 - 2003 baseline period. *See* Revised White Bluff BART Analysis at 4-1. EPA looked at the five-year period between 2009 and 2013, SO_2 Cost TSD at 13, Table 7, but inexplicably excluded the maximum and minimum years during this five-year period. *Id*. The effect of excluding these two years is to increase artificially the emissions baseline for White Bluff. S&L FIP Cost Report at 3. There is no reasoned explanation for excluding two of the five recent years' of emissions data in calculating the baseline. EPA should use the average emissions from all five years to determine the baseline as it is more representative of the anticipated annual emissions from the White Bluff units.

(ii) EPA uses an incorrect methodology that artificially inflates the SO_2 emission reductions achievable with scrubbers.

After having incorrectly identified the baseline emissions for White Bluff, EPA then apparently ignores the baseline emissions when estimating the SO_2 reductions that are achievable with the scrubbers. In an apparent attempt to inflate the emission reductions achievable at White Bluff through the installation of scrubbers, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 for each unit and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. *See* White Bluff_R6 cost revisions2.xlsx, "Cost Effectiveness" tab, EPA Docket ID EPA-R06-OAR-2015-0189-0093. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. *Id*. This methodology is patently incorrect. It assumes the baseline emissions are based on maximum monthly averages, which significantly overstates the annual averages actually used to calculate baseline emissions.

To correctly estimate the SO_2 emission reductions, EPA must multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the five-year baseline period. S&L FIP Cost Report at 3. As detailed in the S&L FIP Cost Report, EPA's inappropriate use of maximum monthly emission rates overstates the achievable emission reductions at White Bluff by between 150 and 900 tons per year. *Id*. at 4, Table 2.

(iii) EPA improperly underestimates the costs by approximately $200 million to justify scrubbers at White Bluff.

EPA based its cost calculations for dry FGD on the costs provided by Entergy in its Revised White Bluff BART Analysis, and presented its analysis of the costs for scrubber installation at White Bluff in its SO_2 Cost TSD. However, EPA's analysis is full of errors, which resulted in an underestimation of the scrubber costs at White Bluff by approximately $200 million.

First, the costs in the Revised White Bluff BART Analysis are significantly outdated, and EPA failed to adequately account for this factor in its analysis. The costs for a dry scrubber provided in the Revised White Bluff BART Analysis were based on (1) a study provided to Entergy by S&L in 2009, which provided a line-itemized cost estimate that included contractor equipment, material, and labor costs for two semi-dry scrubbing systems; and (2) costs provided by Alstom in December 2009 to supply two semi-dry scrubbing systems, escalated by 10% based on updated price information from Alstom. SO_2 Cost TSD, at 2. However, even with the updated cost information from Alstom, the information provided in the Revised White Bluff BART Analysis is now at least five years out of date and significantly undervalues the costs of installing dry scrubbers at White Bluff. EPA attempted to address this issue by escalating the Alstom cost information to 2013 dollars using the Chemical Engineering Plant Cost Indices ("CEPCI"). However, EPA's use of the CEPCI inadequately escalated the projected vendor costs. According to S&L, EPA underestimated escalation significantly using the CEPCI – by over $36 million – rather than using updated vendor pricing. S&L FIP Cost Report at 11. Further, this underestimation of the cost escalation was carried throughout EPA's analysis in the SO_2 Cost TSD and resulted in a total underestimation of the costs for scrubber installation of over $85 million. *Id*. at 12, Table 7.

Second, EPA improperly excluded from the cost calculation legitimate costs that Entergy would incur to install dry scrubbers at White Bluff. EPA incorrectly eliminated over $115 million in costs from Entergy's cost analysis. *See* S&L FIP Cost Report at 8, 10. EPA mistakenly assumed certain Balance of Plant ("BOP") costs were included in the Alstom scope of work, so it eliminated these costs as duplicative. As the S&L FIP Cost Report explains, EPA improperly eliminated several BOP costs from Entergy's cost analysis:

- costs for the reagent handling system;
- costs for the ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney;

- the costs to apply an acid resistant coating to the chimney shell to protect the concrete from downwash effects;
- the costs associated with replacing the continuous emissions monitoring systems ("CEMS") and associated recalibration and testing costs; and
- costs calculated as percentages of the BOP equipment, material and labor costs.

Id. at 7-8. In total, by eliminating these costs, EPA underestimated the BOP costs by approximately $31 million. *Id*. at 8. EPA also suggested that the costs for one absorber vessel could be eliminated but cited no basis for its assumption that two absorber vessels are adequate for White Bluff. Entergy disagrees with EPA's assumption regarding the number of absorber vessels for White Bluff. *See* S&L FIP Cost Report at 17.

EPA also eliminated approximately $41.7 million for Entergy's Owner's costs,[11] despite the fact that such costs are allowed under EPA's Coal Quality Environmental Cost ("CUECost") model. *Id*. at 10. EPA claimed that such costs had not been documented, were duplicative of other costs or did not appear to be valid costs under the Control Cost Manual methodology. 80 Fed. Reg. at 18,971. For example, EPA improperly eliminated Entergy's capital suspense costs without explaining why such costs were duplicative of other costs or not valid under the Control Cost Manual methodology. Capital expenditure costs include both direct assigned and allocated expenses. Allocated expenses represent overhead costs associated with administrators, engineers and supervisors to the capital projects for which they provide services. Each function at Entergy charges its overhead costs to a "Capital Suspense" project, which is then allocated to the appropriate capital project. Capital suspense, therefore, is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and Administrative and General ("A&G") (Corporate Accounting) rates. Because capital suspense costs are a portion of total capital expenditure costs, these costs are not duplicative of other costs.[12] For example, capital suspense costs do not include labor, administrative, and related elements that are present in Entergy's Internal Control costs. *See* SO_2 Cost TSD at 9. It was entirely proper for Entergy to include these costs in its control technology cost estimates. According to EPA's Control Cost Manual, overhead costs should be counted in the total annual cost of a project. Total annual cost is comprised of direct costs, indirect costs, and recovery credits. Control Cost Manual at 2-7. Indirect costs specifically include overhead costs. *Id.* at 2-8; 3-32.

Third, EPA significantly under-estimated the direct Operating and Maintenance ("O&M") costs projected for the scrubbers by using its Integrated Planning Model ("IPM") Spray Dryer Absorber ("SDA") cost model to scale the O&M costs rather than estimating these costs using current utility pricing information. *See* SO_2 Cost TSD at 14, Table 8. The IPM model includes several assumptions that fail to take into account site-specific factors. S&L FIP Cost Report at 13-14. Accordingly, the IPM model is not consistent with the BART Guidelines,

[11] These same improper exclusions were made with respect to EPA's analysis of BART controls for NOx at White Bluff and Lake Catherine Unit 4.
[12] Entergy had previously supplied this information on capital suspense costs to EPA. *See* 80. Fed. Reg. at 18,971, n. 55.

which requires a source-specific evaluation of controls costs. BART Guidelines, at Section IV.D.5 . EPA also erroneously scaled the indirect annual costs, all of which were estimated as percentages of capital cost, by using a scaling factor that did not depend at all on the capital costs. *See* S&L FIP Cost Report at 17.

Fourth, in the design for the dry scrubbers, the Revised White Bluff BART Analysis had assumed that White Bluff would burn a coal corresponding to an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu, which is in excess of the sulfur level of the coals the units have historically burned. EPA criticized Entergy for this assumption and revised the White Bluff baseline emission rates and projected post-control emission rates used for the cost effectiveness analysis. *See* SO_2 Cost TSD at 12-14. However, it is proper, when conducting a BART cost analysis, to consider future fuel flexibility. The BART Guidelines advise that "[t]he baseline emissions rate should represent a realistic depiction of anticipated annual emissions for the source." 70 Fed. Reg. 39,104, 39,167 (July 6, 2005) (codified at 40 C.F.R. Part 51 App. Y). Although the BART Guidelines explain that anticipated annual emissions are *generally* estimated based on annual emissions from a baseline period assuming conditions of past practice, *id*. at 39,167-68, EPA has approved BART determinations that assume "worst-case coal scenarios." *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. 9,318, 9,325-26 (Feb. 18, 2014); Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,584-85 (Sept. 21, 2011). Hourly CEMS data confirm that EPA's selection of 0.68 lb/MMBtu as the design basis for the capital costs is completely inadequate and would not achieve compliance with the FIP-proposed emission limit of 0.06 lb/MMbtu unless fuel sulfur limitations were imposed. Based on historical data and potential fuels that can be fired at White Bluff, 1.2 lb/MMBtu is an appropriate fuel sulfur level to design dry FGD systems for White Bluff. *See* S&L FIP Cost Report at 15-16.

If Entergy were constrained as to the type of coal that it could burn at White Bluff after the installation of controls, it would be necessary to reflect such a constraint in the cost of compliance, as it would force Entergy to continue purchasing higher-cost, low sulfur coal. Historically, Entergy has purchased lower sulfur coal than required by permit to ensure full compliance with applicable emission rates and to minimize costs of compliance with market-based emission programs. If White Bluff were to install BART controls, such considerations would become less meaningful and lower-cost, higher sulfur coal would enable Entergy to meet its BART obligations for less cost. Nonetheless, in the S&L FIP Cost Report, S&L used White Bluff's current emission rate of 0.68 lb/MMBtu to evaluate site-specific O&M costs. S&L FIP Cost Report at 15.

Finally, although Entergy removed Allowance for Funds Used During Construction ("AFUDC") from the final Revised White Bluff BART Analysis in response to comments from EPA on the Proposed White Bluff BART Analysis, Entergy disagrees with EPA that AFUDC should not be considered in the control costs.[13] AFUDC is the time value of money on the investment in the technology that is incurred during the construction, which could reach \$30 million to \$60 million during the 30-46 months of construction that would be needed to install

[13] As noted in the Revised White Bluff BART Analysis, Entergy revised its five-factor analysis of controls at White Bluff as requested by EPA staff in an effort to expedite consideration of the analysis but expressly reserved the ability to include AFUDC in future cost control analyses. Revised White Bluff BART Analysis, at 5-4.

major control equipment such as scrubbers on a large unit. AFUDC includes the interest as part of the capital cost, which is standard accounting and rate-making treatment of such costs and it was appropriate for Entergy to have initially included AFUDC in the White Bluff control costs. In its comments on the Proposed White Bluff BART Analysis, EPA claimed that AFUDC is not allowed by EPA's Control Cost Manual because "the CCM uses overnight costing methodology." EPA Region 6 Comments on White Bluff BART Analysis, at 1 (Aug. 21, 2013) EPA Docket ID EPA-R06-OAR-2015-0189-0044. However, contrary to EPA's assertion, the Control Cost Manual does not even address the use of the overnight methodology as being the basis for estimating costs. *See* S&L FIP Cost Report at 6. In fact, the calculation provided as an example in the Control Cost Manual specifically includes AFUDC as a variable. Control Cost Manual at 1-32, 2-44. The fact that the example "assumes" AFUDC is equal to zero does not reflect a decision by EPA that AFUDC should be excluded from emissions control costs, but instead is an explicit recognition of that category of costs.

EPA also has claimed that the U.S. Energy Information Administration ("EIA") uses overnight costs to project plant costs. *See* S&L FIP Cost Report at 6. However, this is a mischaracterization of the EIA methodology. According to EIA, "[s]tarting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational." EIA, *Updated Capital Cost Estimates for Electricity Generation Plants*, at 2, n.2 (Nov. 2010).[14] Despite EPA's claims, the Control Cost Manual does not preclude inclusion of AFUDC and the EIA specifically takes such costs into account for an electric generating unit. Accordingly, the costs of controls for dry scrubbers at White Bluff should appropriately include AFUDC.

3. The costs for dry scrubbers at White Bluff, based on current estimates, are too high to constitute BART.

EPA's use of outdated costs in its cost calculation, its exclusion of certain legitimate costs for the construction of dry scrubbers, and its failure to take into consideration fuel flexibility at White Bluff renders EPA's analysis artificially low and inappropriate for evaluating the cost effectiveness of dry scrubbers on White Bluff for regional haze purposes. To correct EPA's deficiencies, Entergy commissioned a revised dry FGD cost analysis from S&L that takes into account the current costs for dry scrubber installation as compared to the costs that would have been incurred in 2009 or 2010. *See White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831, Sargent & Lundy (July 2015) ("2015 S&L FGD Report") (attached as Exhibit B and incorporated by reference herein). The 2015 S&L FGD Report also takes into account site-specific factors at White Bluff that have an effect on costs. Finally, the study also uses the current SO_2 emission rates at White Bluff for the O&M costs. For the capital cost estimate, S&L uses a design basis of 1.2 lb/MMBtu sulfur coal. As explained in the S&L FIP Cost Report, the current maximum monthly average emission rates are not an appropriate basis for sizing the scrubbers. The equipment must be sized to handle the maximum short-term emission rate. S&L FIP Cost Report at 14-15.

[14] Available at http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf.

The Revised White Bluff BART Analysis had estimated the costs to install dry scrubbers at White Bluff to be approximately $670 million. Revised White Bluff BART Analysis, at 5-6, Table 5-3. The 2015 S&L FGD Report estimates that the total costs of dry scrubbers at White Bluff will be in excess of $1 billion. 2015 S&L FGD Report at ES-1. When the remaining useful coal-fired life of these units is factored into the analysis, dry FGD installation at White Bluff would be indisputably cost-prohibitive.

Based on the S&L analysis, operating the dry FGD systems at White Bluff for only six to seven years would result in an average cost effectiveness of **$7,689-$8,599**/ton at Unit 1 and of **$7,642-$8,546**/ton at Unit 2. S&L FIP Cost Report at 23, Table 11. EPA has determined costs of substantially less than this magnitude to be cost-prohibitive on numerous occasions, including in this very same rulemaking. For example, for AECC McClellan Unit 1, even though EPA claimed that "[s]witching to diesel is projected to result in considerable visibility improvement," EPA rejected SO_2 BART limits based on switching to diesel because EPA determined that diesel, with an average cost effectiveness of $7,145/ SO_2 ton removed, was not "cost-effective in view of the incremental visibility improvement." 80 Fed. Reg. at 18,959. EPA also rejected combustion controls as NOx BART for AECC McClellan Unit 1 based on an average cost effectiveness of $6,261/NOx ton removed, which, according to EPA "is not within the range of what we generally consider to be cost-effective." *Id*. at 18,961. Further, EPA declined to impose dry FGD as BART in Arizona, where the average cost effectiveness was estimated to be $5,091/ton. Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,331-33; Final Arizona Regional Haze FIP, 79 Fed. Reg. 52,420, 52,436 (Sept. 3, 2014). In North Dakota, EPA approved the state's determination that a cost effectiveness of $6,525 per ton was excessive for NOx controls and did not constitute BART. Proposed North Dakota FIP, 76 Fed. Reg. at 58,630; Final North Dakota Regional Haze FIP, 77 Fed. Reg. 20,894, 20,896 (Apr. 6, 2012). And, in Montana, EPA concluded that certain SO_2 controls with a cost effectiveness of $5,442/ton and $6,365/ton were not cost effective. Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,047 (Apr. 20, 2012); Final Montana Regional Haze FIP; 77 Fed. Reg. 57,864, 57,866 (Sept. 18, 2012). Notably, although EPA found that dry sorbent injection was cost effective on a cost-per-ton basis, 77 Fed. Reg. at 24,047, EPA concluded that the costs were not justified by the visibility improvement, which it calculated to be $30 million per deciview. 77 Fed. Reg. at 57,895. This is magnitudes lower than the cost-per-deciview of dry FGD at White Bluff Units 1 and 2, which, for Unit 1, would be approximately **$3.1 billion** per deciview at Caney Creek and **$2.7 billion** per deciview at Upper Buffalo and, for Unit 2, approximately **$2.9 billion** per decivew at Caney Creek and **$2.6 billion** per deciview at Upper Buffalo.[15]

[15] These numbers were calculated from the deciview improvement attributable to White Bluff Units 1 and 2 based on EPA's "scaling methodology." *See* 80 Fed. Reg. 18,997. This methodology results in an improvement at Caney Creek of .036 dv from Unit 1 and .038 from Unit 2 and an improvement at Upper Buffalo of .040 from Unit 1 and .043 from Unit 2. Even if the deciview improvements projected from EPA's CALPUFF modeling were used, *see* 80 Fed. Reg. at 18,972, the $/deciview calculation would not support the installation of dry FGD as BART at White Bluff. Entergy estimates that the costs based on the CALPUFF modeled improvement for Unit 1 would be approximately $135 million per deciview at Caney Creek and $144 million per deciview at Upper Buffalo and, at Unit 2, the costs would be approximately $145 million per deciview at Caney Creek and $143 million per deciview at Upper Buffalo.

The CAA requires that a BART determination consider the degree of anticipated visibility improvement. 42 U.S.C. § 7491(g)(2). Accordingly, EPA cannot mandate that a source "spend millions of dollars for new technology that will have no appreciable effect on the haze." *Am. Corn Growers v. EPA*, 291 F.3d 1, 7 (D.C. Cir. 2002). However, EPA's proposed controls do exactly this. The improvements predicted at Caney Creek and Upper Buffalo from controls on White Bluff Units 1 and 2 based on EPA's scaling methodology are only a fraction of a deciview. Even the CALPUFF predicted visibility improvements at Caney Creek and Upper Buffalo from the installation of dry FGD at White Bluff Units 1 and 2 are less than 1 deciview from each unit, *see* 80 Fed. Reg. 18,972, making them imperceptible to the human eye. *See* Section III.C.2.iii below. The massive cost of installing dry scrubbers at White Bluff to achieve these insignificant improvements, whether on a dollar per deciview basis or a dollar per ton basis, would be *much higher* than the costs that EPA has previously rejected as BART and that EPA proposes to reject as BART in this Proposed Rule. Accordingly, the installation of dry scrubbers cannot be considered BART for SO_2 at White Bluff.

4. Emissions reductions at White Bluff will be achieved through interim controls.

In addition to its plan to cease combusting coal at White Bluff by 2028, Entergy proposes to meet interim SO_2 emission rate reductions prior to 2028 through a reduction in the units' permitted SO_2 emission rates. The units currently have a permitted 3-hour average SO_2 limit of 1.2 lb/MMBtu. Entergy proposes to lower this limit to a rolling 30-day average limit of 0.6 lb/MMBtu beginning in 2018.

NOx BART for all EGUs in Arkansas, including White Bluff, should be compliance with CSAPR given that EPA already has determined that CSAPR is better than BART. 77 Fed. Reg. 33,642 (June 7, 2012). EPA has proposed to take this same approach in the Texas Regional Haze FIP and has approved several state regional haze SIPs that adopted this approach. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,821; *see also* Proposed Pennsylvania SIP Approval, 80 Fed. Reg. 2,841, 2,844 (Jan. 21, 2015); Final Minnesota SIP Approval, 77 Fed. Reg. 34,801, 34,801-02 (June 12, 2012). EPA should adopt this same approach in the final Arkansas Regional Haze FIP and provide that compliance with CSAPR is NOx BART for all of Arkansas' EGUs.

However, in the event EPA continues to require Arkansas' EGUs to meet source-specific NOx BART limits in the final FIP, Entergy proposes that the units meet a rolling 30-boiler operating day average NOx limit of 1,342.5 lb NOx/hr. This limit is based on the installation of LNB/SOFA and Entergy would be prepared to meet this limit no later than three years from the effective date of the final rule.[16] *See* 79 Fed. Reg. at 18,974-75. Although the cost effectiveness

[16] As explained further in Section III.E below, this limit is different from the limit that Entergy proposed as NOx BART in its Revised White Bluff BART Analysis. The revised limit is necessary due to the changed operating conditions at White Bluff over the past few years. The plant is now economically dispatched through the Midcontinent Independent System Operator ("MISO") and is spending greater amounts of time at lower load than it did in 2013, when the Revised White Bluff BART Analysis was submitted to ADEQ, and in prior years. The emissions guarantee that Entergy received from Foster Wheeler, the vendor that Entergy has selected to supply the NOx control technology, only applies to loads of 50% of capacity or greater. Therefore, a revised limit is necessary

of installing LNB/SOFA would significantly decrease as a result of a revised remaining useful life analysis for the units, if EPA does not adopt its CSAPR equals BART approach for Arkansas, Entergy is prepared to install these controls as part of its comprehensive visibility improvement proposal.

This combination of CSAPR compliance or, in the alternative, LNB/SOFA installation, and acceptance of a lower SO_2 emission rate through the remaining useful coal-fired life of the White Bluff units should be determined to be BART for White Bluff. No additional controls are justified given Entergy's proposal to limit the number of years of coal-fired operation at White Bluff.

B. EPA's Reasonable Progress Analysis And Proposed Determination Are Inconsistent With Other Regional Haze Development Processes.

1. EPA's reasonable progress analysis does not follow prior actions.

For reasonable progress purposes, EPA failed to undertake an appropriate reasonable progress analysis, including the crucial first step of determining whether additional controls are, in fact, necessary for Arkansas to make reasonable progress. *See* Section III.C below. EPA targeted only Independence in its analysis and subsequent decision to impose SO_2 and NOx limitations on the two coal-fired units at Independence. By focusing solely on Independence, EPA's reasonable progress analysis for the proposed Arkansas FIP abandons the analytical approach and determinative standards that guided previous reasonable progress analyses and determinations. In place of the criteria and procedures that EPA established in its own guidance or utilized and applied in previous approvals/disapprovals of regional haze SIPs or promulgation of regional haze FIPs, EPA made the arbitrary decision to review Independence simply because it believes "it would be unreasonable to ignore" the facility. 80 Fed. Reg. at 18,992. EPA failed to consider any lesser level of controls, the relative costs of such controls, the effectiveness of the controls in improving visibility or the cost per deciview improvement associated with the proposed controls.

EPA arbitrarily elected to propose controls for Independence that are unnecessary for Arkansas to demonstrate reasonable progress, provide no perceptible visibility improvement and exceed the cost estimates documented for other sources under other approved plans where EPA declined to impose reasonable progress controls. Further, EPA failed to follow its own guidance, which indicates that "States should consider a broad array of sources and activities when deciding which sources or source categories contribute significantly to visibility impairment." *Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program*, at 3-2 (June 1, 2007) ("Reasonable Progress Guidance").[17] The arbitrary evaluation process that EPA followed in the Proposal not only distorts the goals and objectives of the Regional Haze Program, but it also is contrary to EPA's own requirements for uniformity and regional consistency.

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to ensure that the White Bluff units can comply with the NOx limit at the lower loads that have become a more common operating condition for the units.

[17] Available at http://www.epa.gov/ttn/caaa/t1/memoranda/reasonable_progress_guid071307.pdf.

(i) EPA failed to determine visibility impact and the scope of Arkansas sources' contribution to visibility impairment.

EPA's singular attention on Independence for reasonable progress controls is unsubstantiated and is patently arbitrary and capricious. Despite identifying the 10 largest point sources of SO_2 and NOx within Arkansas, EPA focused only on the top three: White Bluff, Independence, and Flint Creek. Because White Bluff and Flint Creek are subject to BART, EPA concluded that no additional controls are necessary at those sources and the subsequent reasonable progress analysis fell solely on Independence. *Id.* at 18,991-92. Other than stating that these plants are the three largest sources, EPA provides no explanation for ignoring the other seven large point sources.[18]

EPA's failure to assess and document the contribution to visibility impairment at any relevant Class I area from *any* Arkansas point source, including Independence, is contrary to past rulemakings and is completely inconsistent with the detailed approach taken by EPA Region 6 in its promulgation of the regional haze FIP for Texas. *See generally*, Proposed Texas Regional Haze FIP, 79 Fed. Reg. 74,818. There, the Agency completed a multi-step evaluation that included: Q/D analysis (i.e., total emissions – 24-hour maximum annualized – divided by distance to the Class I area) for each Texas point source and relevant Class I area to identify those point sources requiring further evaluation,[19] a photochemical modeling scenario utilizing source apportionment to quantify visibility impacts from the sources identified in the Q/D analysis,[20] and an extinction percentage threshold to arrive at what EPA claimed was a common breakpoint in potential visibility improvement.[21] This analysis was key to the development of EPA's approach for proposing appropriate controls by indicating for which sources the installation of controls are needed and would be worthwhile. *See id.*at 74,839 (explaining that the results "suggest that controlling a small number of sources will result in visibility benefits at both Class I areas, and that rather than evaluating controls at all facilities identified by Texas combined, a subset of those facilities (and some additional facilities not identified) may be reasonable.").

EPA took this same approach in other states. *See* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,352-53; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,058-59; and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,624-26. By notable contrast, EPA's Region 6 office did not perform *any* evaluation to identify *any* Arkansas point sources contributing to visibility impairment (or the scope of contribution) at Caney Creek or Upper Buffalo. EPA also performed multi-source emissions analysis using CAMx in most of those other states rather than looking only at the potential impact on visibility using the CALPUFF,

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[18] EPA must provide a reasoned basis for failing to analyze whether these other emission sources should be evaluated for reasonable progress purposes. Indeed, EPA should have conducted multi-source modeling to demonstrate that the other six largest point sources in Arkansas do not contribute to visibility impairment in the Arkansas Class I areas.

[19] *Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans (FIP TSD)*, Appendix A at A-4 (Nov. 2014) ("TX FIP TSD").

[20] *Id.* at A-15 – A-26.

[21] *Id.* at A-49.

single source model, as it did in Arkansas. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78; Proposed Montana Regional Haze FIP, 77 Fed. Reg. at 24,050; Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. at 58,635.

EPA proceeded to complete the required four-factor reasonable progress analysis in those other states only after narrowing the list of potential point sources. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,872. *See also* Proposed Arizona Regional Haze FIP, 79 Fed. Reg. at 9,138, 9,352-53 (Feb. 18, 2014); Proposed Montana Regional Haze FIP, 77 Fed. Reg. 23,988, 24,058-59 (Apr. 20, 2012); and Proposed North Dakota Regional Haze FIP, 76 Fed. Reg. 58,570, 58,624-26 (Sept. 21, 2011). No doubt, this process was utilized because the Regional Haze Rule requires that additional controls for proposed emission reductions, as identified in an implementation plan, *must be needed to achieve reasonable progress*.[22] EPA's failure to follow these same procedures in the Arkansas Proposed FIP is completely inconsistent with its prior actions and renders the Proposed FIP arbitrary and capricious.

(ii) EPA's review and determination of cost effectiveness is inconsistent with other state programs.

EPA's disregard for consistent reasonable progress review and analysis continued into the required four-factor analysis. After making the unsubstantiated and unsupportable determination to target only Independence, EPA applied different dollar per ton cost effectiveness thresholds for proposed controls at the plant, which are out of line with the standards applied in other regional haze SIPs and FIPs. Specifically, EPA's Proposal attempts to justify a cost effectiveness of dry FGD at Independence totaling \$2,477/SO_2 ton removed for Unit 1 and \$2,686/SO_2 ton removed for Unit 2. 80 Fed. Reg. at 18,944. This far exceeds the cost threshold approved by EPA for reasonable progress controls for other states. *See* Section III.C.3 below.

(iii) EPA's evaluation and application of NOx control requirements is inconsistent with other state programs.

EPA's decision to evaluate *and propose* NOx controls at Independence stands completely opposite its decision not to even evaluate NOx controls for Texas' point sources despite similar visibility conditions. *See* Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,873 ("we are limiting our analyses to consideration of SO_2 controls for these EGU sources, as our modeling indicates that the impacts from these sources on the 20% worst days are primarily due to sulfate emissions."). EPA's decision in this Proposal to impose NOx limits on Independence is inexplicable given the very low visibility improvement projected and the fact that such limits are completely unnecessary for Arkansas to stay below the URP. *See* 40 C.F.R. §§ 51.308(d)(1)(ii) and (d)(3) (explaining that "emission reduction measures" must be necessary to achieve reasonable progress goals). Visibility at Arkansas' Class I areas is only insignificantly impacted by all Arkansas point sources, even less so by point source contributions of NOx, and almost not

[22] *See* 40 C.F.R. §§ 51.308(d)(1)(i)(B) and (d)(3). Logic dictates that if a point source's contribution to visibility impairment is determined to be insignificant then additional controls are not necessary to achieve reasonable progress.

at all by Independence. *See* Section III.C.2 below. Further, Arkansas has sufficiently documented that those same Class I areas remain well ahead of the approved URP. *See* Section III.C.1 below.

2. EPA is obliged to act consistently in promulgating rules.

Reviewed individually, the issues identified above evidence an unjustified and inconsistent application of the Regional Haze Rule. Collectively, they demonstrate EPA's complete disregard for consistent review and uniform evaluation that is required by regulation. EPA's consistency regulations strive for "standardiz[ed] criteria, procedures and policies" when "implementing and enforcing the act." 40 C.F.R. §§ 56.3(a) and (b). They further oblige the Agency to ensure that actions taken under the Clean Air Act: (1) "[a]re carried out fairly and in a manner that is consistent with the Act and Agency policy as set forth in the Agency rules and program directives" and (2) "[a]re as consistent as reasonably possible with activities of other Regional Offices." 40 C.F.R. § 56.5(a).

In EPA's Arkansas FIP Proposal, EPA abandoned the standardized criteria, procedures and policies that had been used in other regional haze SIPs/FIPs. Even more remarkable, EPA's failure to complete a necessary reasonable progress analysis is the same justification EPA used to reject Arkansas' SIP proposal in the first instance. *See* 80 Fed. Reg. at 18,991 (noting that EPA's partial disapproval of the Arkansas regional haze SIP was based, in part, on the "finding that Arkansas did not complete a reasonable progress analysis and did not properly demonstrate that additional controls were not reasonable").

C. Installing Scrubbers At Independence Is Not Necessary To Demonstrate Reasonable Progress And Cannot Be Justified At This Time.

Units 1 and 2 at the Independence Station are not subject to BART. 80 Fed. Reg. at 18,991. EPA nonetheless treats the units as if they were subject-to-BART units by ignoring whether controls at the units are needed to improve visibility and looking only at whether controls are "cost effective." EPA must first determine that further actions are necessary in Arkansas beyond BART to ensure that visibility improvement is continuing on or below the glide path. *See* 42 U.S.C. § 7491(b)(2) (implementation plans must "contain such emission limits, schedules of compliance and other measures as may be *necessary* to make reasonable progress.") (emphasis added); Reasonable Progress Guidance at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period."). Only if further action is *necessary* for reasonable progress may EPA require additional controls and, even then, EPA must evaluate which controls are appropriate based on the statutory factors. *See* 42 U.S.C. § 7491(g)(1). EPA failed to do this here.

Arkansas' Class I areas, even without the proposed BART controls, are significantly below the URP and are on track to remain so for the next several years. Nonetheless, EPA has proposed to require emissions limits at Independence Units 1 and 2 based on the installation of SO_2 and NOx controls, ostensibly to achieve reasonable progress, and has offered two options for comment. Under Option 1, each coal-fired unit at Independence would be required to meet a rolling 30-day average SO_2 emission limit of 0.06 lb/MMBtu based on the installation and operation of dry FGD systems, and a rolling 30-day average NOx emission limit of 0.15 lb/MMBtu based on the installation and operation of LNB/SOFA. *Id*. at 18,994, 18,997. Under Option 2, the Independence coal-fired units would be required to meet only the SO_2 limit. *Id*. at 18,994.

EPA's justification for imposing SO_2 and NOx emission limits on Independence is not based on rational policy, legal or environmental grounds and, as a result, it is arbitrary and capricious. EPA's primary justification for proposing reasonable progress limits at Independence is that "it would be unreasonable to ignore a source representing more than a third of the State's SO_2 emissions and a significant portion of NOx point source emissions." *Id*. at 18,992. EPA further supports its conclusion that emission limits based on the installation of major control technology are justified based on a finding that the proposed controls at Independence are cost effective. *Id*. at 18,994-97. However, the fact that a source, which is not subject to BART, may have significant SO_2 or NOx emissions, or that it would be cost effective to control such emissions, is irrelevant for reasonable progress purposes. EPA has not used such an inapplicable and inadequate justification to identify sources for control under a reasonable progress analysis in any other Regional Haze FIP. EPA did not appropriately analyze which sources, if any, should be controlled for reasonable progress and did not follow the procedures it has regularly used in other regional haze FIPS. *See* Section III.B above. Further, emission limits on Independence during at least the first planning period are unnecessary to demonstrate reasonable progress as Arkansas already is below the glide path for the first planning period.

EPA also improperly relied on CALPUFF modeling in its reasonable progress analysis and, as a result, has significantly over-estimated Independence's contribution to visibility impairment and the deciview improvement that would result from the installation and operation of emissions controls at Independence.[23] The visibility impairment at Arkansas' two Class I areas is caused overwhelmingly by point sources outside of the state, secondary organic aerosols - biogenic ("SOAB"), mobile sources, and Arkansas area sources,[24] not by Arkansas point sources such as power plants. EPA's singular focus on Independence will not result in any meaningful improvement in visibility at Caney Creek or Upper Buffalo and will not affect Arkansas' continued progress toward the 2064 natural visibility goal, but will cost EAI's customers and co-owners over $1 billion.

1. Controls on Independence do not further the goal of the Regional Haze Program.

The goal of the Regional Haze Program is the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I areas resulting from manmade air pollution. 42 U.S.C. § 7491(a)(1). Notably, the goal is not simply to reduce

[23] It is noteworthy that EPA issued, on July 29, 2015, a proposal to remove CALPUFF from EPA's preferred list of dispersion models used for Clean Air Act purposes. 80 Fed. Reg. 45,340 (July 29, 2015).

[24] EPA defines an area source as "a collection of similar emission units within a geographic area." EPA, *Introduction to Area Source Emission Inventory Development*, at 1.1-3 (Jan. 2001) *available at* http://www.epa.gov/ttnchie1/eiip/techreport/volume03/iii01_apr2001.pdf. "Area sources collectively represent individual sources that are small and numerous, and that have not been inventoried as specific point, mobile, or biogenic sources. Individual sources are typically grouped with other like sources into area source categories." *Id*.

emissions for the sole purpose of achieving emission reductions; rather, the program is designed to reduce emissions *where necessary* to remedy and prevent visibility impairment. 42 U.S.C. § 7491(b)(2). The program undertakes a gradual approach toward this goal, to assure that reasonable progress is being made while accounting for economic and technological constraints. The program is not designed to achieve the ultimate goal of eliminating visibility impairment immediately but, rather, over time. As EPA itself noted when establishing the Regional Haze Rule, which provides the states with a 64-year period to reach natural visibility conditions at Class I areas:

> [a]dvancements in technology and changes in economic factors will likely provide opportunities for implementation of new cost effective control measures to assure reasonable progress. The structure of EPA's rule is designed to require States, through the SIP process, to review the statutory factors on a periodic basis and determine appropriate changes to their strategies based on that review.

64 Fed. Reg. 35,714, 35,752 (July 1, 1999). EPA takes this extended period of time into account in providing guidance to the states on establishing their RPGs: "you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4; *see also id*. at 4-1 ("Given the significant emissions reductions that we anticipate to result from BART" and other Clean Air Act programs "it may be all that is necessary to achieve reasonable progress in the first planning period for some States.").

Thus, the threshold question is whether reductions in a source's emissions are *necessary* to achieve reasonable progress for the planning period under consideration. 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal") (emphasis added). Here, where Arkansas is already below the URP for this planning period and projected to remain so for more than a decade, the answer is clearly no. EPA's proposed imposition of unnecessary controls is clearly unreasonable. *See Michigan v. EPA*, 135 S.Ct. at 2706 (requiring EPA's regulatory requirements to be "within the scope of its lawful authority" and its decision-making process to be "logical and rational").

(i) Arkansas' Class I areas are, and will remain, below the glide path well beyond the first planning period.

The proposed emission limits for Independence are not necessary to achieve reasonable progress because ADEQ has demonstrated that Caney Creek and Upper Buffalo will be below the glide path in 2018. State of Arkansas, *State Implementation Plan Review for the Five-Year Regional Haze Progress Report*, at 55-56 (May 2015) ("Arkansas Five-Year Progress Report").[25] Specifically, Caney Creek and Upper Buffalo have both shown improved visibility for the most impaired and least impaired days since 2001 and are projected to continue to improve. The current five-year average shows that, as of 2011, Caney Creek has achieved 73%

[25] Available at http://www.adeq.state.ar.us/air/planning/pdfs/ar_5yr_prog_rep_review-final-6-2-2015.pdf.

of Arkansas' 2018 RPG of 3.88 dv and Upper Buffalo has achieved 66% of Arkansas' 2018 RPG of 3.75 dv. Arkansas Five-Year Progress Report at 60. Based on the five-year rolling averages and projected data, both Class I areas are on schedule to achieve their 2018 RPGs for the 20% worst days. *Id*. at 55, 57. Data from Caney Creek and Upper Buffalo show that the goal of no visibility degradation on the 20% best days will be achieved and that visibility has and will continue to improve. *Id*. at 42-43. EPA acknowledges these facts in the Proposal: "Arkansas Class I areas and those outside of Arkansas most significantly impacted by Arkansas sources are projected to meet the URP for the first planning period." 80 Fed. Reg. at 18,992. As a result of emission reductions achieved through regional and national programs, including MATS, CAIR, and CSAPR, future Clean Air Act programs such as implementation of the 1-hour SO_2 NAAQS, the revised ozone NAAQS and the Clean Power Plan, as well as the reductions for White Bluff and Independence that Entergy is proposing and the BART controls that EPA has proposed for the other sources in Arkansas, there is every reason to project continued improvement in visibility in Caney Creek and Upper Buffalo well beyond 2018.[26]

Entergy has conducted additional modeling using the Comprehensive Air Quality Model with Extensions ("CAMx") and statistical analysis that supports this conclusion. The CAMx modeling demonstrates that the haze index at Caney Creek and Upper Buffalo will remain below the URP for many years to come.[27] Recent IMPROVE monitoring data show that the haze index has been consistently below the URP in both Caney Creek and Upper Buffalo. Trinity Consultants, Inc. ("Trinity") also performed statistical analyses on the data from both Caney Creek and Upper Buffalo to statistically project the haze index trend through 2018.[28] Using a Ranked Statistical Analysis, the haze index for the average of the W20 days in 2018 is projected to be 20.07 dv at Caney Creek and 20.91 dv at Upper Buffalo.[29] These numbers are far below the URP for the first planning period and demonstrate that no source in Arkansas, including Independence, needs to install controls for Arkansas to remain below the glide path. *See* Figures 1 and 2.

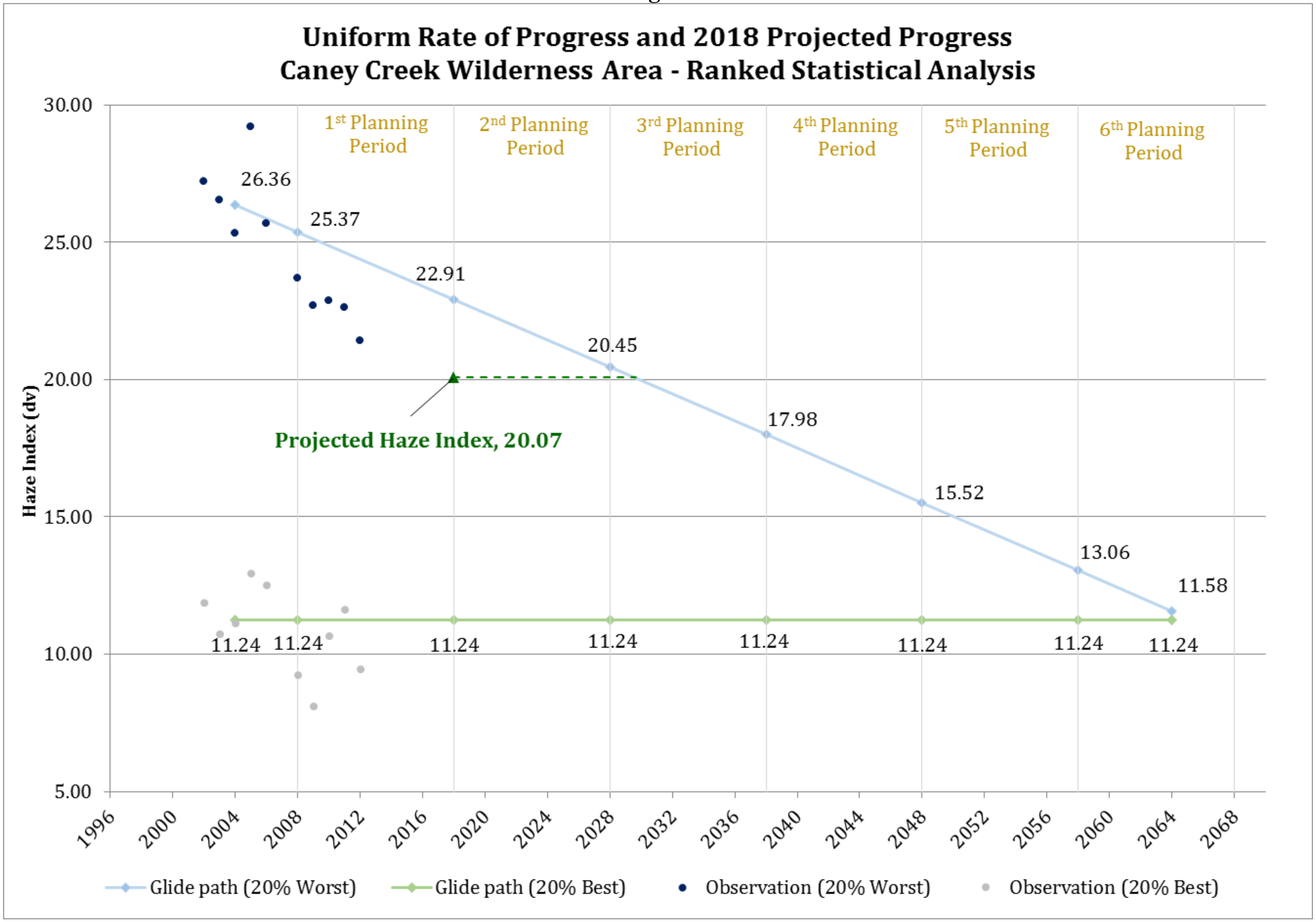
[26] The 5-Year Progress Report for Missouri also demonstrates that Mingo and Hercules Glades are on track to meet the 2018 visibility goals and Missouri has determined that further reductions are not necessary. *Missouri Regional Haze Plan: 5-Year Progress Report*, at 4, 17 (Aug. 29, 2014) ("The [monitoring] analyses in the 2009 RH plan demonstrate that the 2018 visibility goals for Mingo and Hercules Glades will be largely achieved from Electric Generating Unit (EGU) emission reductions resulting from the federal Clean Air Interstate Rule (CAIR) program."); *see also* Proposed Missouri SIP, 77 Fed. Reg. 11,958, 11,966 (Feb. 28, 2012) ("EPA proposes to find that Missouri has appropriately established goals that provide for reasonable progress towards achieving natural visibility conditions."); Final Missouri SIP, 77 Fed. Reg. 38,007 (June 26, 2012).

[27] The CAMx modeling was conducted by Trinity Consultants, Inc. Trinity's *Regional Haze Modeling Assessment Report*, which describes the CAMx modeling methodology that Trinity used to evaluate the visibility improvement of controls at Independence and White Bluff, is provided as Exhibit C to these comments.

[28] Trinity's report identifying why a statistical analysis was performed on the IMPROVE data and why the Ranked Statistical Analysis was selected is included as Exhibit D to these comments and incorporated by reference herein. *IMPROVE Data Statistical Analysis*, Trinity Consultants (July 2015) ("Trinity Report").

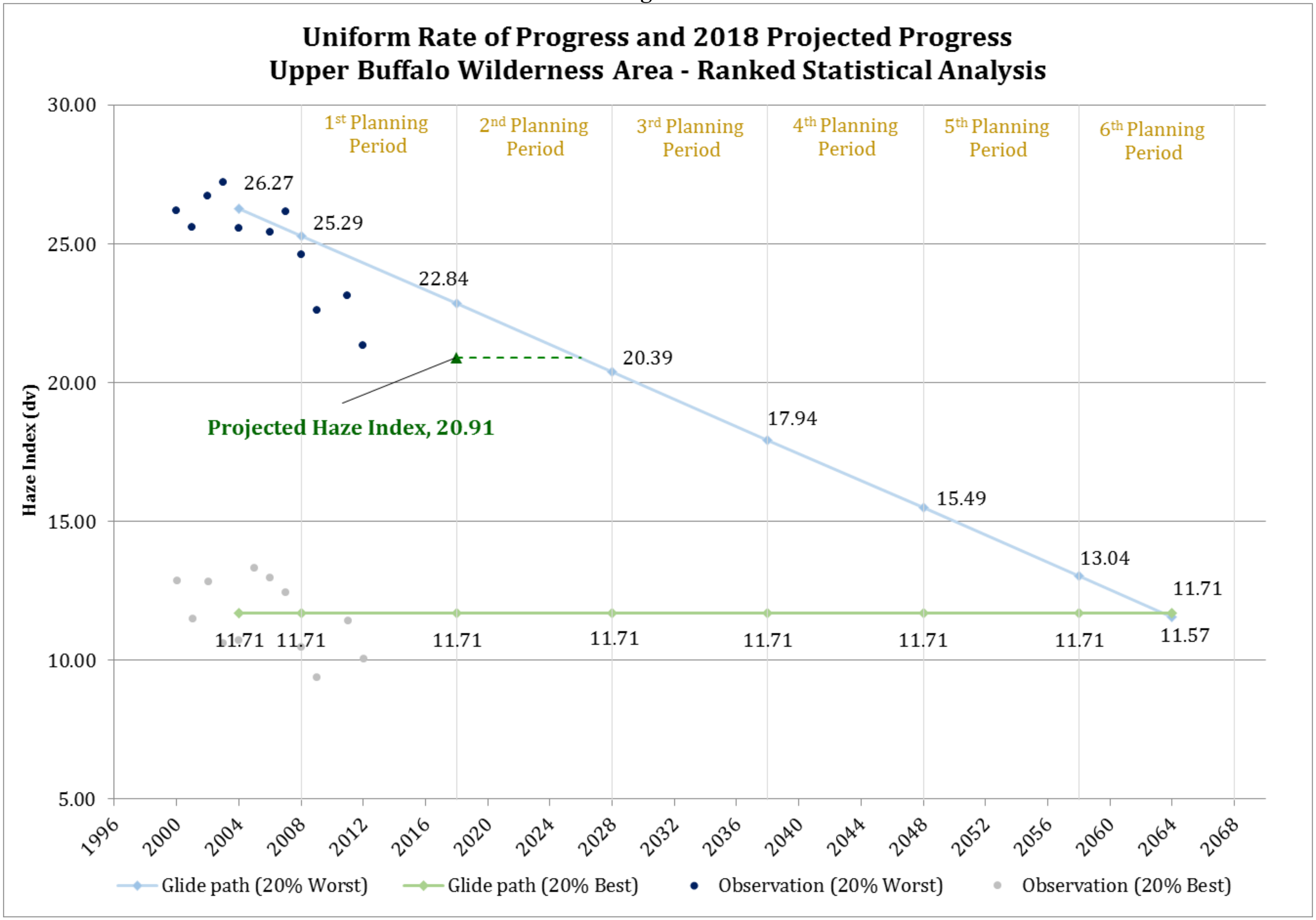
[29] Trinity also performed a Trend Statistical Analysis of the data, which projects even lower visibility impairment of 18.02 dv at Caney Creek and 20.44 dv at Upper Buffalo, Trinity Report at Section 3.1, but Entergy is using the more robust and conservative Ranked Statistical Analysis to demonstrate the expected trend in visibility impairment.

Figure 1



Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
Projected Haze Index, 20.07
11.24
11.24
11.24
11.24
11.24
11.24
11.24
11.24
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figure 2



Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
Projected Haze Index, 20.91
11.71
11.71
11.71
11.71
11.71
11.71
11.71
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figures 1 and 2 show the data plots for the 20% worst days and the 20% best days from the IMPROVE network for Caney Creek and Upper Buffalo, respectively. These plots demonstrate that the W20 days since 2007 have consistently been below the URP and that visibility is improving faster than the URP. Trinity applied a Ranked Statistical Analysis to all of the haze index values calculated using the new IMPROVE equation and the data from the IMPROVE monitoring network and constructed a future projection curve to statistically project the haze index at Caney Creek and Upper Buffalo in 2018. Trinity Report at Section 3.2. As demonstrated in Figure 1, the Ranked Statistical Analysis indicates that the haze index in 2018 at Caney Creek will be 20.07 dv, which is 2.84 dv below the URP. Indeed, if EPA does nothing at all (i.e., imposes no BART limits on sources in Arkansas or emission limits on Independence), Caney Creek would not approach the glide path until 2030. Figure 2 shows very similar results for Upper Buffalo, which would not approach the glide path until at least 2026. In light of these projections, which align with ADEQ's glide path demonstrations (*see* Arkansas Five-Year Progress Report at 57-60), SO_2 and NOx emission limits at Independence are unnecessary for reasonable progress purposes for at least a decade.

Notably, the Ranked Statistical Analysis conservatively assumes that there will be no additional emissions reductions resulting in visibility improvements after 2018, including emissions reductions from out-of-state sources, which cause over 50% of the visibility impairment in Arkansas Class I areas, or from area and mobile sources, which account for approximately 9.25% of the visibility impairment at Caney Creek and 9.68% at Upper Buffalo.[30] Assuming that MATS achieves the emissions reductions that EPA projects in terms of acid gas controls and retirements,[31] that CSAPR tightens the SO_2 emission budgets in the second phase, that sources will be forced to make additional SO_2 and NOx reductions to comply with the 1-hour SO_2 NAAQS and the revised ozone NAAQS, and that the Phase 2 CAFE fuel economy standards drive further reductions from mobile sources, the haze index in Caney Creek and Upper Buffalo will continue to improve beyond 2018 without controls on Independence.

(ii) Emissions from out-of-state sources and Arkansas mobile and area sources have a more significant impact on Arkansas' Class I areas.

In the Proposal, EPA's reasonable progress analysis primarily focuses on point source contributions to light extinction at Caney Creek and Upper Buffalo. As a result, EPA chose to limit its evaluation of potential reasonable progress controls solely to Arkansas' largest emitting point sources, and, specifically, to Independence. However, as demonstrated in Figures 3 and 4 below, Arkansas point sources are relatively insignificant contributors to visibility impairment in Caney Creek and Upper Buffalo compared to most of the other regions modeled by CENRAP and are not even the biggest source group contributor in Arkansas to visibility impairment in these Class I areas.[32]

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[30] These percentages are based on CENRAP's Particulate Matter Source Apportionment Technique ("PSAT") tool.

[31] Entergy expects the MATS Rule will go forward before the end of this planning period along with the associated emission reductions. *See* footnote 5 above.

[32] Figures 3 and 4, as well as Figures 5 and 6, were developed by extracting the modeled source apportionment extinction data from the CENRAP PSAT tool for Caney Creek and Upper Buffalo. The data obtained were organized by geographic region and source category, so that the individual contribution of each source category in each geographic region could be determined.

Figure 3

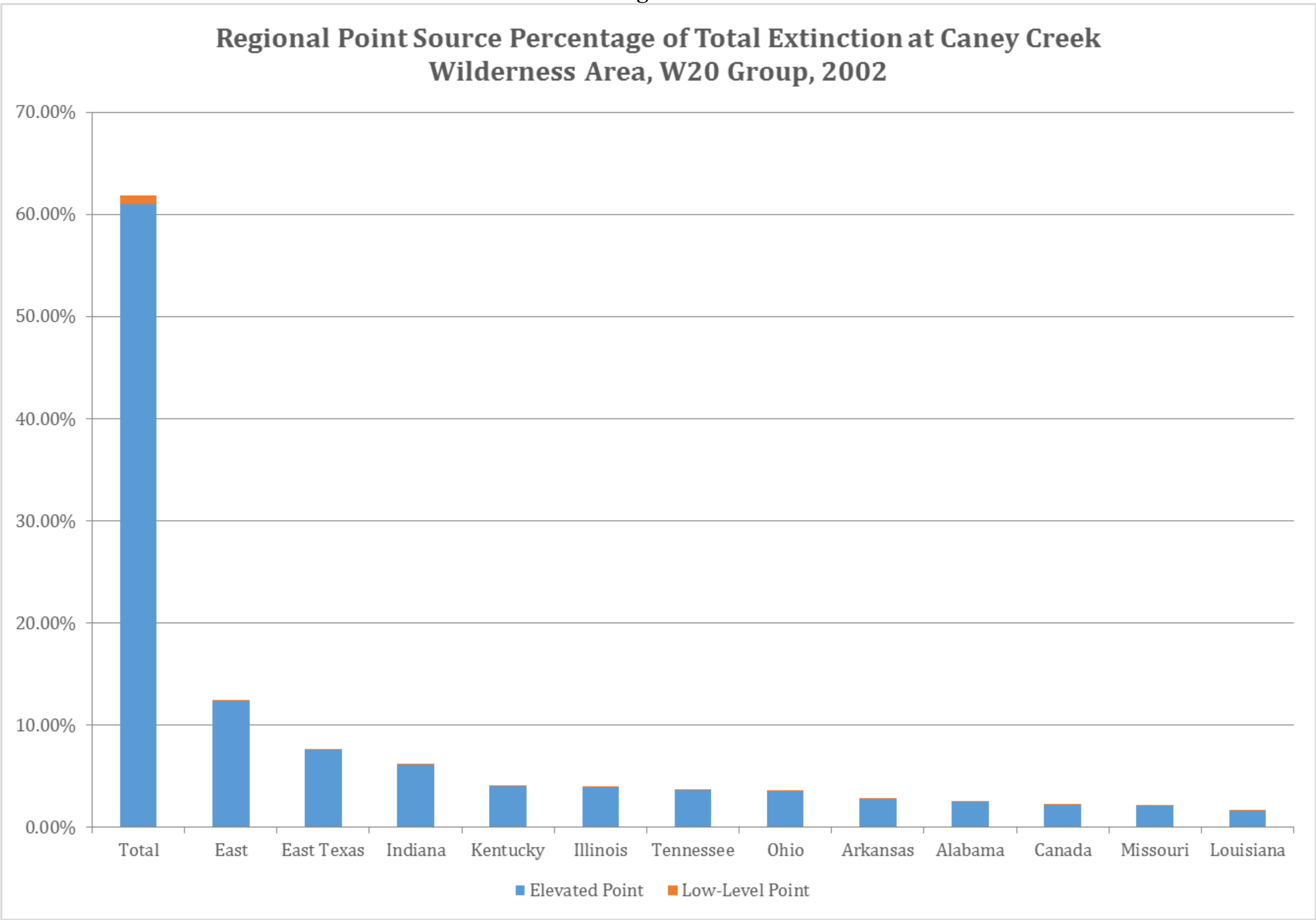
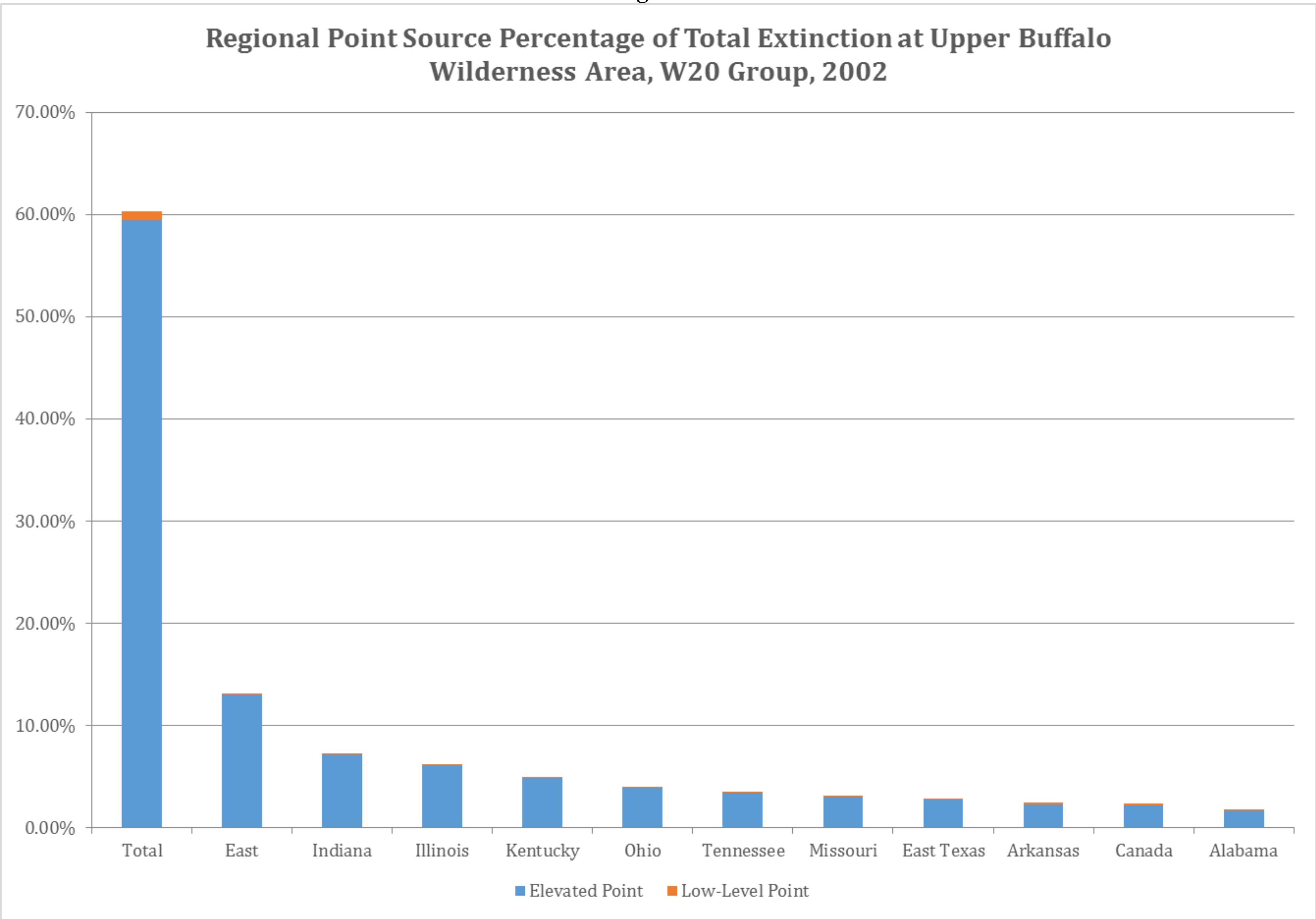

Regional Point Source Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
East Texas
Indiana
Kentucky
Illinois
Tennessee
Ohio
Arkansas
Alabama
Canada
Missouri
Louisiana
Elevated Point
Low-Level Point

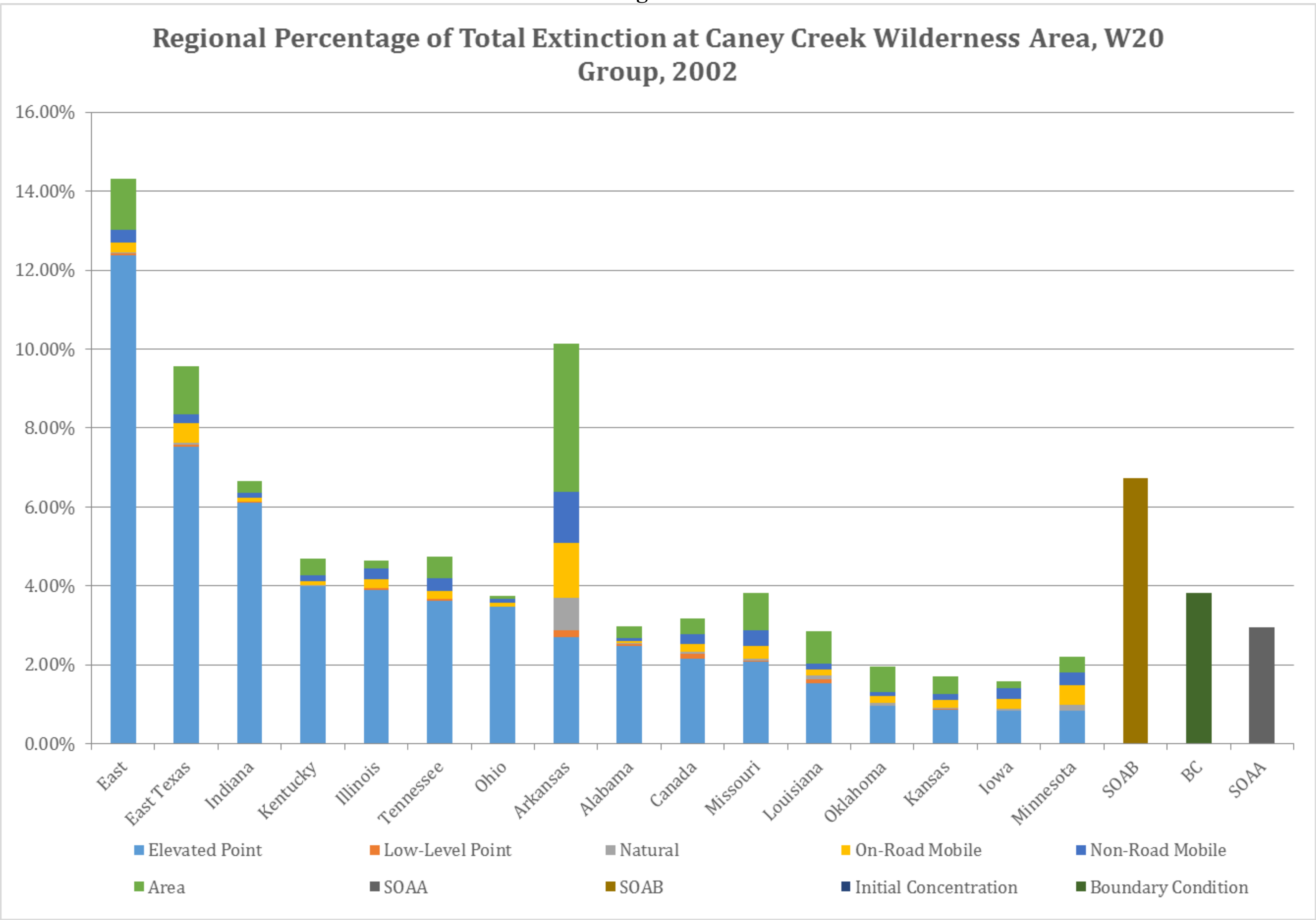
Figure 4


Regional Point Source Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002
70.00%
60.00%
50.00%
40.00%
30.00%
20.00%
10.00%
0.00%
Total
East
Indiana
Illinois
Kentucky
Ohio
Tennessee
Missouri
East Texas
Arkansas
Canada
Alabama
Elevated Point
Low-Level Point

Figures 3 and 4 display the modeled percent contribution of elevated and low-level point sources to the total light extinction from the significantly contributing geographic regions. Also included in these figures is the combined total percentage contribution from all point sources in all geographic regions. Of a total point source contribution of 61.85% at Caney Creek in 2002, Arkansas's point sources contributed only **2.87%**, making Arkansas the eighth highest point source contributor. Similarly, of the 60.35% total point source contribution at Upper Buffalo in 2002, Arkansas was the ninth highest point source contributor with only a **2.47%** contribution.

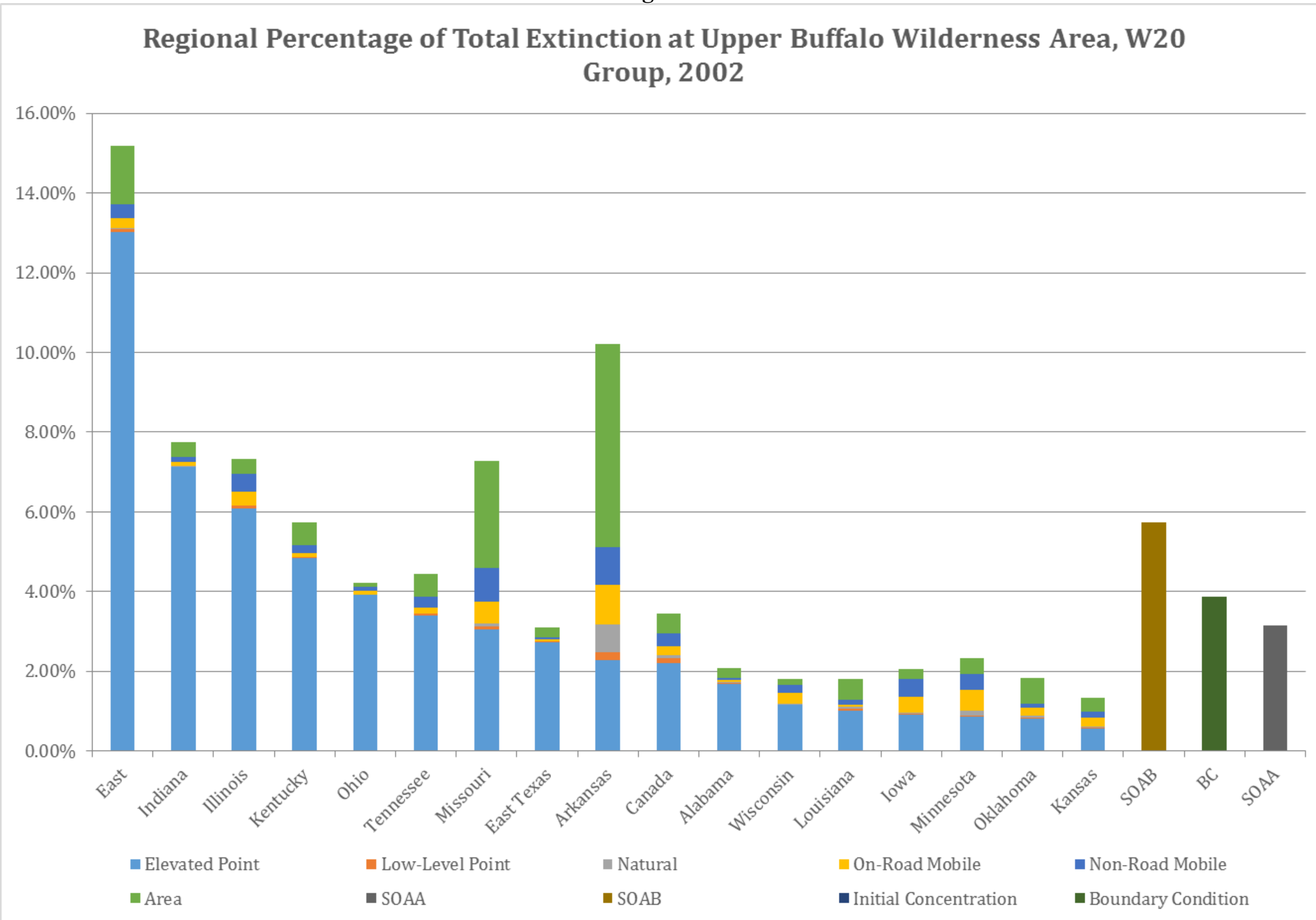
In addition, unlike these other regions, where point sources contribute the majority of visibility impairment to Arkansas' Class I areas, most of Arkansas' share of the contribution to visibility impairment comes from Arkansas area and mobile sources, not point sources. *See* Figures 5 and 6 below.

Figure 5



Regional Percentage of Total Extinction at Caney Creek Wilderness Area, W20 Group, 2002
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
East
East Texas
Indiana
Kentucky
Illinois
Tennessee
Ohio
Arkansas
Alabama
Canada
Missouri
Louisiana
Oklahoma
Kansas
Iowa
Minnesota
SOAB
BC
SOAA
Elevated Point
Low-Level Point
Natural
On-Road Mobile
Non-Road Mobile
Area
SOAA
SOAB
Initial Concentration
Boundary Condition

Figure 6



Regional Percentage of Total Extinction at Upper Buffalo Wilderness Area, W20 Group, 2002
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
2.00%
0.00%
East
Indiana
Illinois
Kentucky
Ohio
Tennessee
Missouri
East Texas
Arkansas
Canada
Alabama
Wisconsin
Louisiana
Iowa
Minnesota
Oklahoma
Kansas
SOAB
BC
SOAA
Elevated Point
Low-Level Point
Natural
On-Road Mobile
Non-Road Mobile
Area
SOAA
SOAB
Initial Concentration
Boundary Condition

At Caney Creek, Arkansas area sources contribute **3.75%** of the overall extinction while Arkansas' combined point source category (i.e., elevated and low-level point sources) contribute only **2.87%**. Even more significantly, Arkansas area sources contributed **5.09%** towards extinction at Upper Buffalo compared to **2.47%** from the combined Arkansas point sources.

Independence's emissions, which comprise only a portion of Arkansas' point source emissions, have even less of an effect on light extinction in either Class I area. As a result, installing emissions controls on Independence will not meaningfully change the haze index at either Class I area.

(iii) Emissions from out-of-state sources will continue to improve.

Entergy's analysis demonstrates that Arkansas' Class I areas will remain below the glide path in the first planning period and well into the second based on actual data (*see* Section III.C.1.i above); however, the analysis also demonstrates that, due to continued emissions reductions at sources outside of Arkansas, these reductions will continue, furthering Arkansas' progress towards background visibility, without controls on Independence. Point source emissions from the other states included in CENRAP's modeling have been steadily decreasing since the early 2000's and that trend is expected to continue. Indeed, a number of sources in East Coast states have recently announced retirements. The U.S. Energy Information Administration predicts that 60 gigawatts of coal-fired power plant capacity will retire by 2020.[33] These units are significant contributors to visibility impairment at Caney Creek and Upper Buffalo and their retirement will further improve visibility. The second phase of CSAPR, the 1-hour SO_2 NAAQS and the revised ozone NAAQS also will result in significant reductions in SO_2 and NOx emissions from the largest point source contributors to Caney Creek and Upper Buffalo, which are all located outside of Arkansas. *See* Figures 7 and 8 (demonstrating declining emissions trends and the contributions of EGUs).

[33] http://www.eia.gov/todayinenergy/detail.cfm?id=15031#

Figure 7

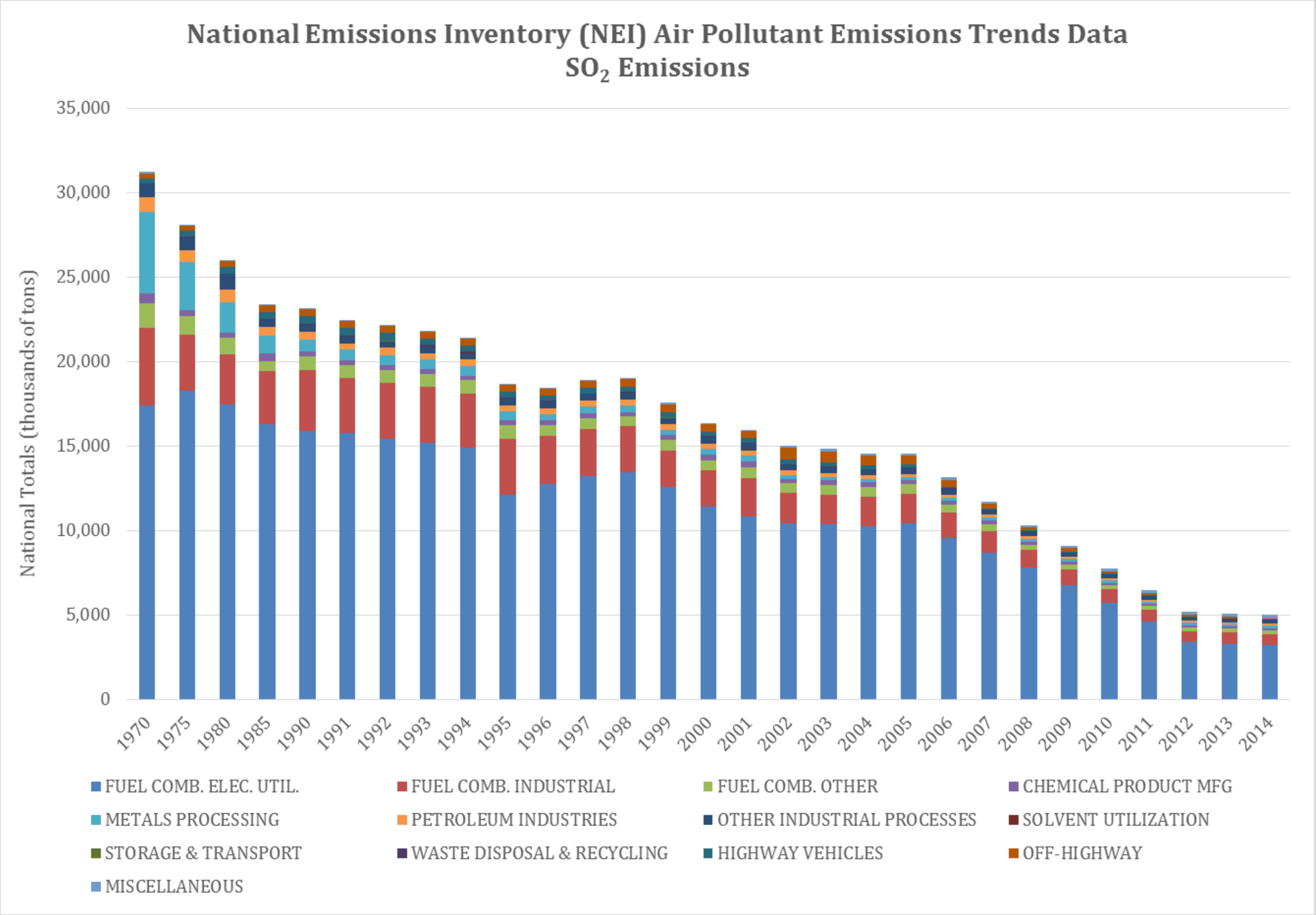
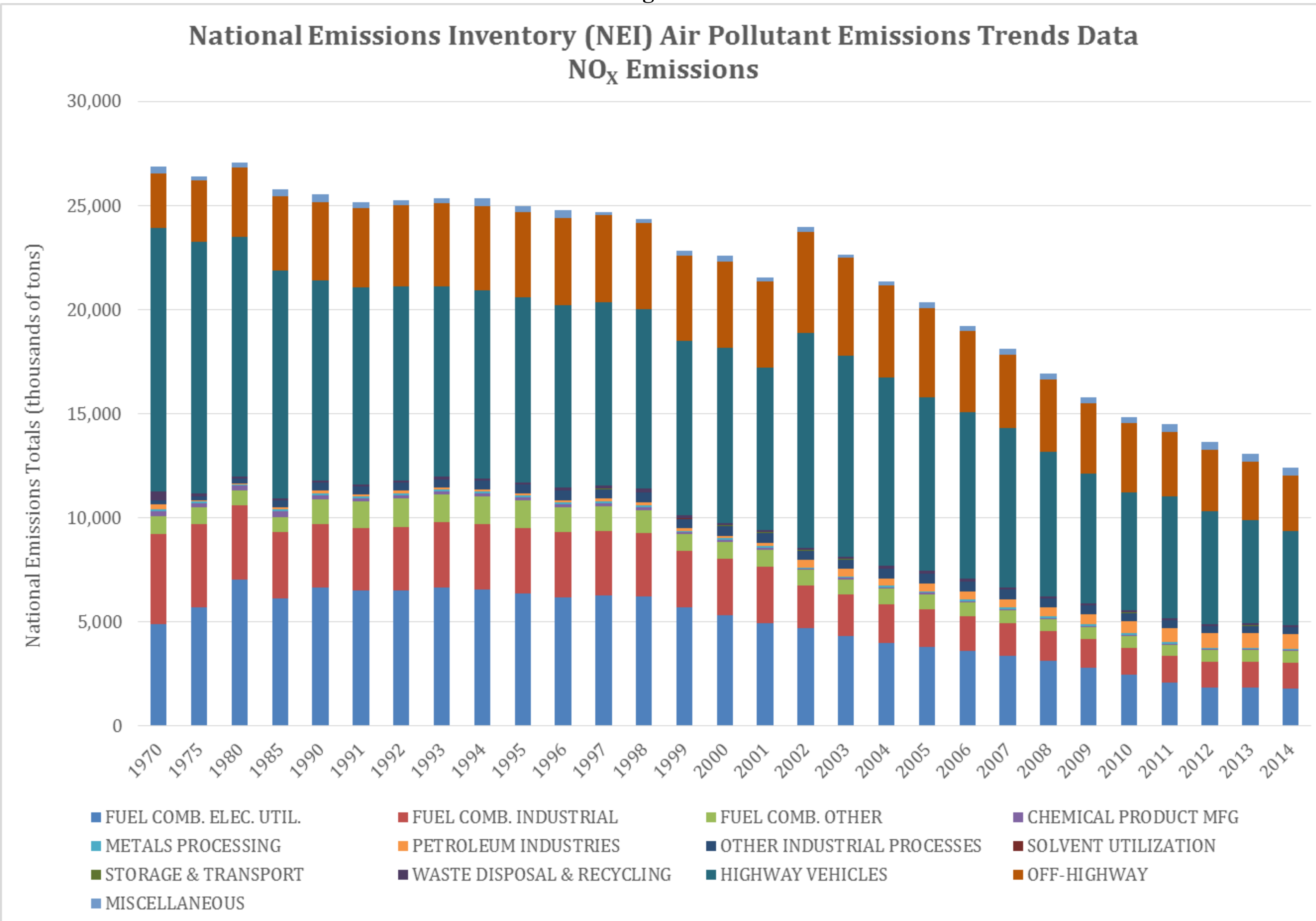

National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data
SO_2 Emissions
National Totals (thousands of tons)
35,000
30,000
25,000
20,000
15,000
10,000
5,000
0
1970
1975
1980
1985
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
FUEL COMB. ELEC. UTIL.
FUEL COMB. INDUSTRIAL
FUEL COMB. OTHER
CHEMICAL PRODUCT MFG
METALS PROCESSING
PETROLEUM INDUSTRIES
OTHER INDUSTRIAL PROCESSES
SOLVENT UTILIZATION
STORAGE & TRANSPORT
WASTE DISPOSAL & RECYCLING
HIGHWAY VEHICLES
OFF-HIGHWAY
MISCELLANEOUS

Figure 8



National Emissions Inventory (NEI) Air Pollutant Emissions Trends Data
NO_X Emissions
National Emissions Totals (thousands of tons)
30,000
25,000
20,000
15,000
10,000
5,000
0
1970 1975 1980 1985 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014
FUEL COMB. ELEC. UTIL.
FUEL COMB. INDUSTRIAL
FUEL COMB. OTHER
CHEMICAL PRODUCT MFG
METALS PROCESSING
PETROLEUM INDUSTRIES
OTHER INDUSTRIAL PROCESSES
SOLVENT UTILIZATION
STORAGE & TRANSPORT
WASTE DISPOSAL & RECYCLING
HIGHWAY VEHICLES
OFF-HIGHWAY
MISCELLANEOUS

According to EPA's Reasonable Progress Guidance, the Agency should have taken the emissions reductions anticipated from CSAPR, as well as other Clean Air Act programs, into account in setting the proposed RPGs for Arkansas:

> Given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States.

Reasonable Progress Guidance at 4-1. EPA completely failed to undertake this "important step" in proposing the RPGs for Arkansas and instead simply focused on controls at Independence.

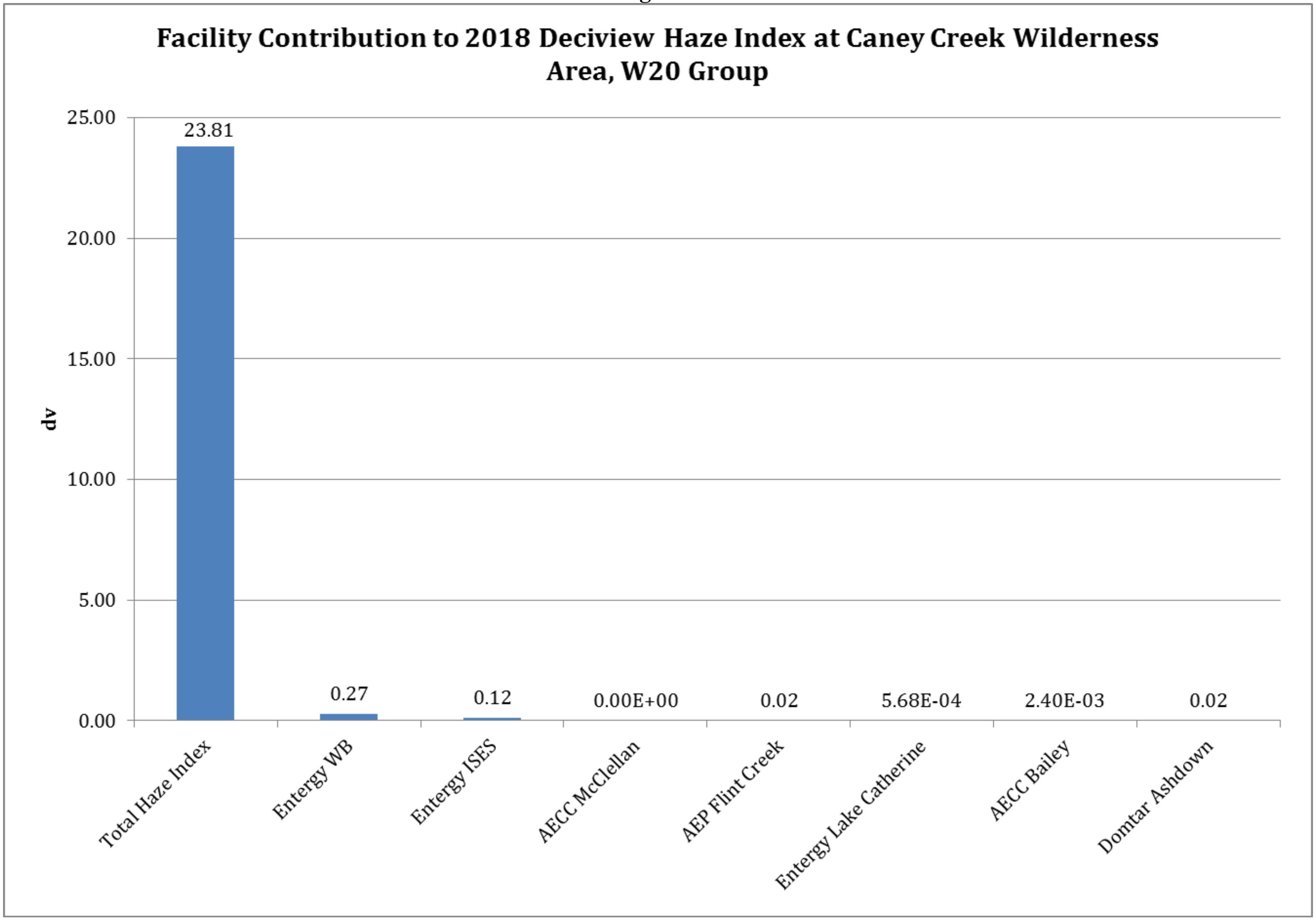
2. Installation of controls on Independence Units 1 and 2 cannot be justified because of the de-minimis benefit toward reasonable progress.

EPA's own analysis counsels against imposing emission limits on Independence. EPA asserts that CENRAP modeling shows that sulfate from *all* point sources included in the regional modeling is projected to contribute to 57% of the total light extinction at Caney Creek on the W20 days in 2018 and 43% of the total light extinction at Upper Buffalo. 80 Fed. Reg. at 18,990. However, EPA recognizes that the CENRAP modeling also demonstrates that sulfate from all (elevated and low level) *Arkansas* point sources is projected to be responsible for only 3.58% of the total light extinction at Caney Creek and 3.20% at Upper Buffalo. *Id*. The contribution of Arkansas point sources' nitrate emissions to visibility impairment at Arkansas' Class I areas is even more insignificant. According to EPA's analysis, nitrate from *all* point sources included in the regional modeling is projected to account for only 3% of the total light extinction at the Caney Creek and Upper Buffalo Class I areas, with nitrate from *Arkansas* point sources being responsible for only 0.29% of the total light extinction at Caney Creek and 0.25% at Upper Buffalo. *Id*. The Independence units' share of emissions to this minimal contribution from Arkansas point sources to visibility impairment at Caney Creek and Upper Buffalo is even less.

Entergy's CAMx modeling confirms that Independence's contribution to visibility impairment is insignificant in both Class I areas. Independence is projected to contribute to only 0.119 dv of visibility impairment at Caney Creek and Upper Buffalo on W20 days in 2018. *See* Figures 9 and 10.[34] This reflects only one half of one percent of the visibility impairment, based on modeling, on the W20 days in either Caney Creek or Upper Buffalo. Yet, based on such a miniscule contribution and with no credible explanation, EPA arbitrarily concludes that SO_2 and NOx controls at Independence are warranted.

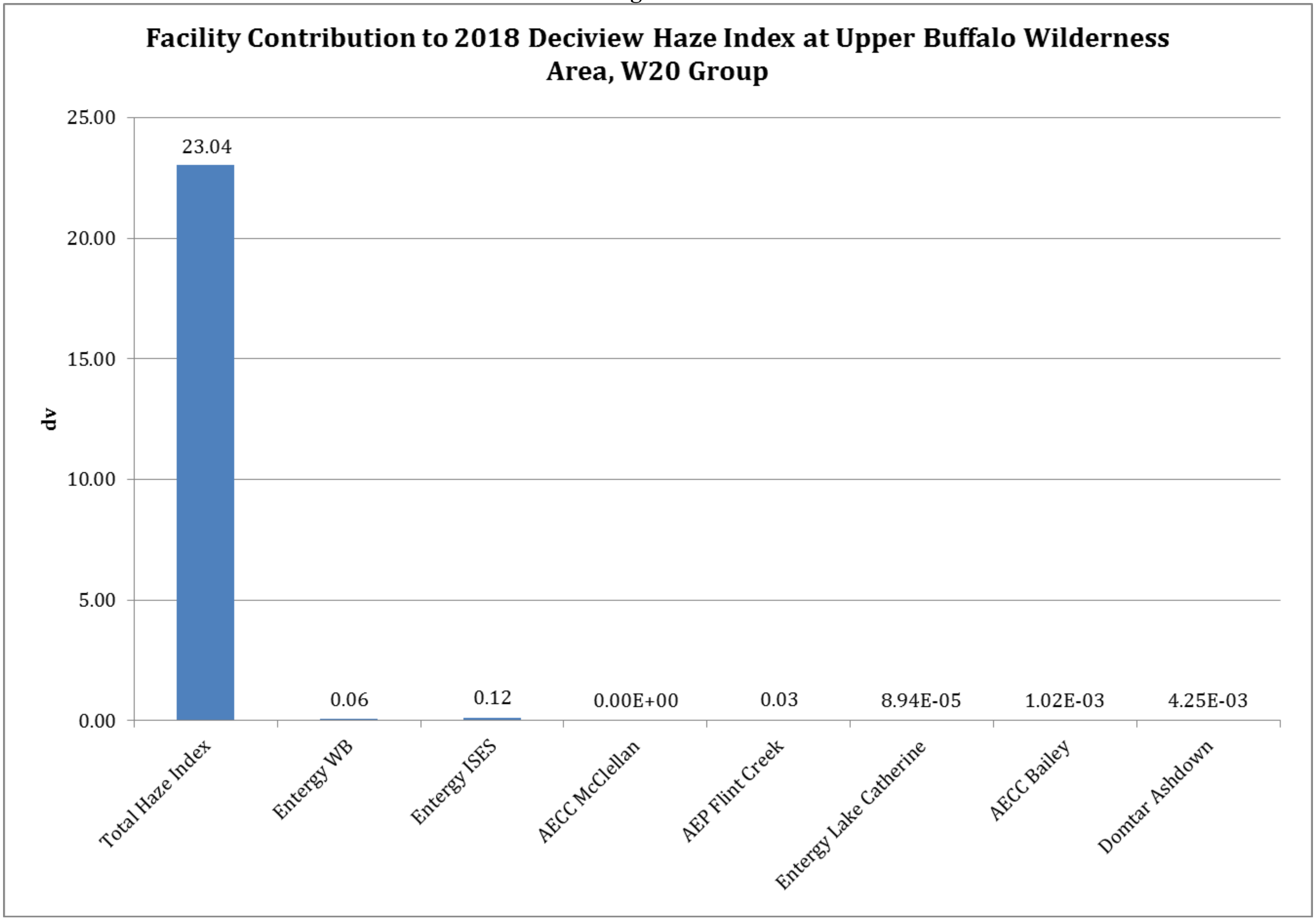
[34] Figures 9 and 10 assume no FIP controls on any of the Arkansas sources. Also, the total haze index values presented in Figures 9 and 10 are based on Entergy's CAMx model predicted total contribution calculated using the new IMPROVE equation, whereas the projected haze index values in Figures 1, 2, and 11 - 14 are based on Trinity's Ranked Statistical Analysis and represent the average haze index for the W20 days. *See* Section III.C.1.i, above.

Figure 9



Facility Contribution to 2018 Deciview Haze Index at Caney Creek Wilderness Area, W20 Group
dv
25.00
20.00
15.00
10.00
5.00
0.00
23.81
0.27
0.12
0.00E+00
0.02
5.68E-04
2.40E-03
0.02
Total Haze Index
Entergy WB
Entergy ISES
AECC McClellan
AEP Flint Creek
Entergy Lake Catherine
AECC Bailey
Domtar Ashdown

Figure 10


Facility Contribution to 2018 Deciview Haze Index at Upper Buffalo Wilderness Area, W20 Group
dv
25.00
20.00
15.00
10.00
5.00
0.00
23.04
0.06
0.12
0.00E+00
0.03
8.94E-05
1.02E-03
4.25E-03
Total Haze Index
Entergy WB
Entergy ISES
AECC McClellan
AEP Flint Creek
Entergy Lake Catherine
AECC Bailey
Domtar Ashdown

(i) CALPUFF modeling cannot be used to justify reasonable progress controls at Independence.

Entergy acknowledges that, under the Regional Haze Rule, "the URP does not establish a 'safe harbor' for the state in setting its reasonable progress goals." 80 Fed. Reg. at 18,992 (referencing 64 Fed. Reg. at 35,732). Nonetheless, EPA must demonstrate that additional controls are rational and economically justifiable and that the amount of progress that would result will be "reasonable based upon the statutory factors." *Id*. EPA has explained that this requires a consideration of the projected visibility benefit expected from the controls. *Id*. at 18,993.

EPA admits that it did not perform refined, multi-state modeling to determine the amount of visibility improvements that would be achieved through the installation of controls because it would be difficult, time-consuming, and expensive. Instead, the Agency took a "thumbnail" approach in an attempt to justify the proposed controls based on how long it would take to achieve background levels. 80 Fed. Reg. at 18,997-98. EPA's use of CALPUFF, a single source model, for evaluating the reasonable progress benefits of installing controls at Independence is misplaced and clearly in error. CALPUFF is not appropriate for reasonable progress purposes as it addresses a fundamentally different question than a proper reasonable progress analysis. TX FIP TSD at A-35. As EPA itself has recognized, CALPUFF is overly simplistic and greatly overstates the effect of single source emissions. BART Guidelines, 70 Fed. Reg. 39,104, 39,121 (July 6, 2005) ("there are other features of our recommended modeling approach that are likely to overstate the actual visibility effects of an individual source. Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source."). CALPUFF also fails to show the effects of multiple sources, and is much less sophisticated in its treatment of the chemical interactions of the different pollutants in the atmosphere than CAMx.

EPA has recognized that CAMx, a photochemical transport 3-dimensional grid model, is a more appropriate modeling tool for reasonable progress purposes. Proposed Texas Regional Haze FIP, 79 Fed. Reg. at 74,877-78. BART analyses assess the impact of a single facility based on the maximum or 98th percentile impacts, regardless of whether the Class I area was actually experiencing high visibility impairment on any given day. Since CALPUFF does not conduct an analysis considering all the emissions from all potential sources, some of the days with the worst model-predicted concentrations could be days that are not significantly impaired. Reasonable progress modeling using a photochemical model, such as CAMx, allows EPA to evaluate impacts from a source (with all other sources included in the modeling) on a Class I area's best and worst days. *Id*. at 74,878.

The draft *EPA Modeling Guidance for Demonstrating Attainment of Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze* (Dec. 2014) ("Draft Modeling Guidance") discusses the use of photochemical grid models and notes that Community Multiscale Air Quality Model ("CMAQ") and CAMx are the most commonly used models for attainment demonstrations. The Draft Modeling Guidance specifically notes that "a modeling based demonstration of the impacts of an emissions control scenario... as part of a regional haze assessment usually necessitates the application of a chemical transport grid model." Draft Modeling Guidance at 22.[35] Throughout the Draft Modeling Guidance, the discussion is focused on items specific to photochemical grid models such as CAMx, including emissions inventories, supporting models, pre-processors, and applying a model to changes in visibility.

According to the Draft Guidance, "the emission sources included in the analysis must be comprehensive, including emissions from all source categories" (i.e., point sources, non-point stationary sources, on-road and non-road mobile sources, fires, and biogenic sources) and "'all' sources of emissions." *Id*. at 32, 36. A CAMx modeling analysis includes a comprehensive inventory, capturing each of these source categories, which are then available to react with available precursors. By using the comprehensive inventory, this limits the amount of precursors available to react with the emissions from a facility or source in question. This has been referred to by EPA as a "dirty background analysis." CALPUFF analyses conducted in support of BART determinations do not consider the full inventory of sources and thus do not account for other pollutants challenging and consuming precursor emissions. As such, ammonia and other precursor pollutants are more fully available to react with a facility's emissions and generate haze impacts in a modeled simulation using CALPUFF. This is referred to by EPA as a "clean background analysis." Therefore, the use of CALPUFF does not reflect the interaction of pollutants in the atmosphere as accurately as CAMx does.

Notably, EPA recently issued a proposal on July 29, 2015, which would remove CALPUFF from EPA's preferred list of air dispersion models in its *Guideline on Air Quality Models* ("Guideline"), in Appendix W to 40 C.F.R. Part 51. Although EPA states that the proposed changes to the Guideline would not affect its recommendation that CALPUFF be used in the BART determination process, EPA made no such assurances regarding the use of CALPUFF for a reasonable progress analysis. Instead, EPA's proposal emphasizes the use of chemical transport models for assessing visibility impacts from a single source or small group of sources. According to the Agency,

> Chemical transport models are well suited for the purpose of estimating long-range impacts of secondary pollutants, such as $PM_{2.5}$, that contribute to regional haze and other secondary pollutants, such as ozone, that contribute to negative impacts on vegetation through deposition processes. These multiple needs require a full chemistry photochemical model capable of representing both gas, particle, and aqueous phase chemistry for $PM_{2.5}$, haze, and ozone.

80 Fed. Reg. at 45,349. CALPUFF is clearly inferior in this regard.

Indeed, EPA's *Interagency Workgroup on Air Quality Modeling Phase 3 Summary Report: Long Range Transport and Air Quality Related Values*,[36] which EPA has made available as a supporting document for the proposed revisions to Appendix W, makes clear that CALPUFF should not be used for a reasonable progress analysis. The report explains that, "[a] modeling system that treats emissions from all known anthropogenic and biogenic emissions sources with

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[35] The Draft Modeling Guidance is available at http://www.epa.gov/scram001/guidance/guide/Draft_O3-PM-RH_Modeling_Guidance-2014.pdf.
[36] Docket ID EPA-HQ-OAR-2015-0310-0004.

realistic chemical and physical transformations should be utilized to estimate future visibility conditions at a Class I area. The most appropriate tool that contains these qualities is a photochemical grid model [such as CAMx]." *Id.* at 6. It further explains that "the results from a BART determination or similar modeling using CALPUFF cannot be directly compared to estimated impacts of emissions controls from a single source on a reasonable progress goal…. Lagrangian puff models are not ideal for reasonable progress demonstrations since they typically characterize one or a small group of sources." *Id.* at 9.

(ii) The CALPUFF modeling vastly overstates the potential visibility improvement from controls on Independence.

EPA's CALPUFF modeling indicates that the SO_2 and NOx emission limits proposed for Independence will result in a 1.952 dv improvement in Caney Creek and a 1.782 dv improvement in Upper Buffalo. *See* Summary of Additional Modeling for Entergy Independence, at 8, Table 5 (Apr. 2015), EPA Docket ID EPA-R06-OAR-2015-0189-0147. However, this range is vastly overstated. Based on the current monitored visibility levels in Caney Creek and Upper Buffalo, the W20 days show that the visibility impairment in 2018 will be approximately 23 to 24 dv. EPA recognizes that sulfate from all of Arkansas' point sources are projected to be responsible for only about 3.6% of total light extinction at Arkansas' Class I areas based on CENRAP modeling. 80 Fed. Reg. at 18,990. This means that sulfate from *all* Arkansas point sources are projected to be responsible for only about 0.83 - 0.86 dv of impairment (23-24 dv x 3.6%). For nitrates, EPA projects that Arkansas point source emissions will account for, at most, 0.29% of the total light extinction at Arkansas' Class I areas. *Id*. at 18,990. Independence's SO_2 and NOx emissions contribute only a portion to the sulfate and nitrate percentages estimated from Arkansas point sources. It would, therefore, be impossible for the SO_2 and NOx limits proposed for Independence to result in deciview improvements at Caney Creek and Upper Buffalo of 1.952 dv and 1.782 dv, respectively. This simple example demonstrates the obvious flaw in EPA's use of CALPUFF for its reasonable progress analysis and, thus, its justification for imposing emission limits on Independence despite the fact that the Class I areas are below the URP.

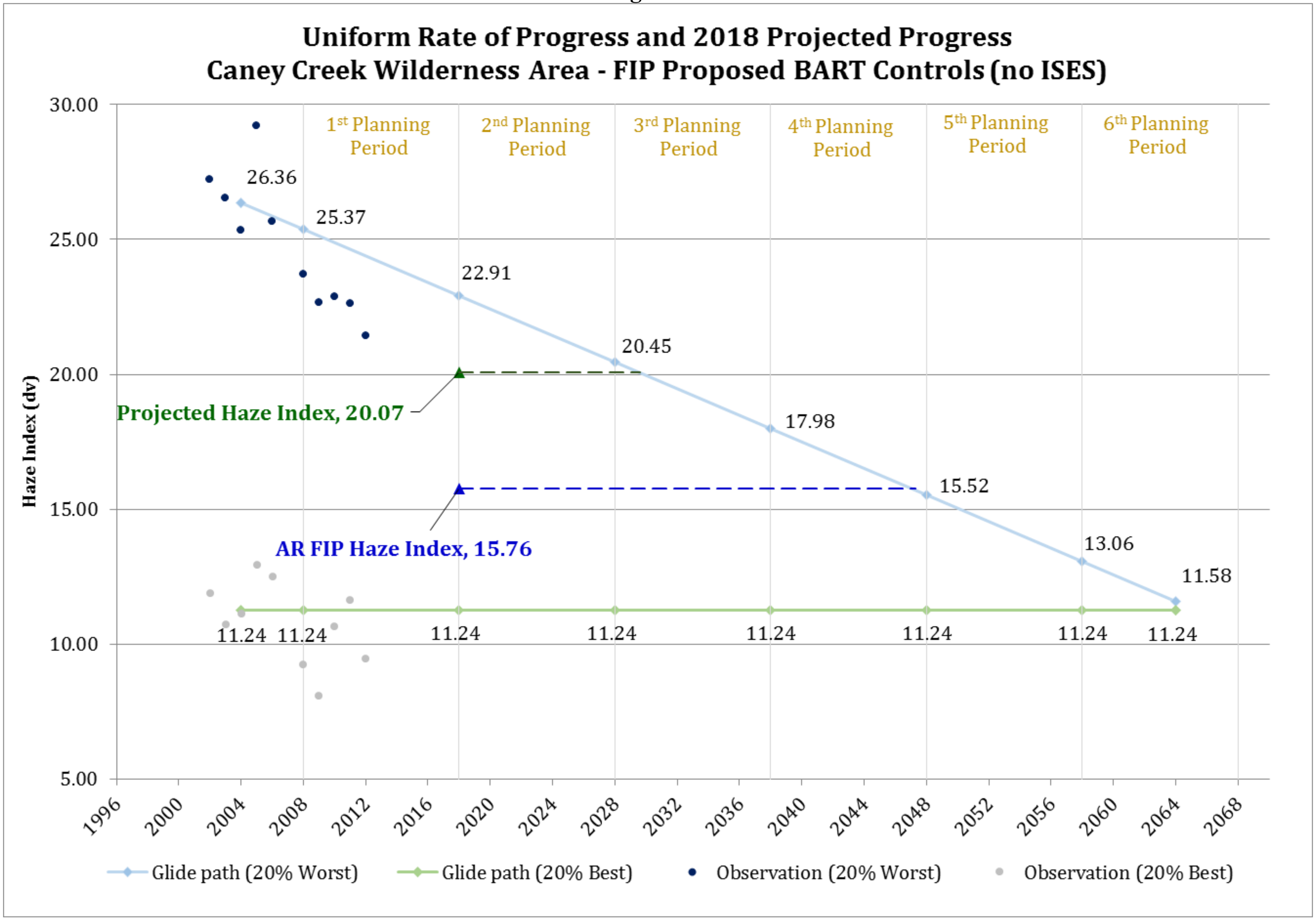
Another illustration demonstrates why CALPUFF greatly overstates the benefits of overall visibility benefits from proposed emission limits. In the Proposal, EPA projects the visibility benefits from the proposed BART controls based on CALPUFF modeling. Based on CALPUFF, EPA's proposed BART limits at White Bluff, Flint Creek Power Plant, Carl E. Bailey Generating Station, John L. McClellan Generating Station, Lake Catherine and Domtar Ashdown Power Boilers will result in projected combined visibility benefits of approximately 4.3 dv at Caney Creek.[37] *See* Figure 11 below. Based on a statistical projection of the haze index in Caney Creek (*see* Section III.C.1 above), that would result in a haze index of 15.76 dv, which would put Caney Creek closer to natural background levels than the glide path. The URP

[37] Trinity derived the 4.3 dv improvement from the CALPUFF modeling by determining the total extinction (in inverse megameters) from each proposed BART source, adding them together, and then calculating the deciview improvement. The resulting 4.3 dv improvement is over five times the total visibility impact attributed to all point sources in Arkansas based on CENRAP's CAMx modeling and 14 times the impact attributed to point sources based on Entergy's current CAMx modeling.

would not reach that haze level until approximately 2048.[38] Indeed, even if you ascribed the CALPUFF-projected benefits to Caney Creek based on the recent IMPROVE levels (approximately 22 dv between 2009 and 2012), the projected haze index would drop to 17.7 dv, which indicates no further action should be needed to remain below the URP until approximately 2038.

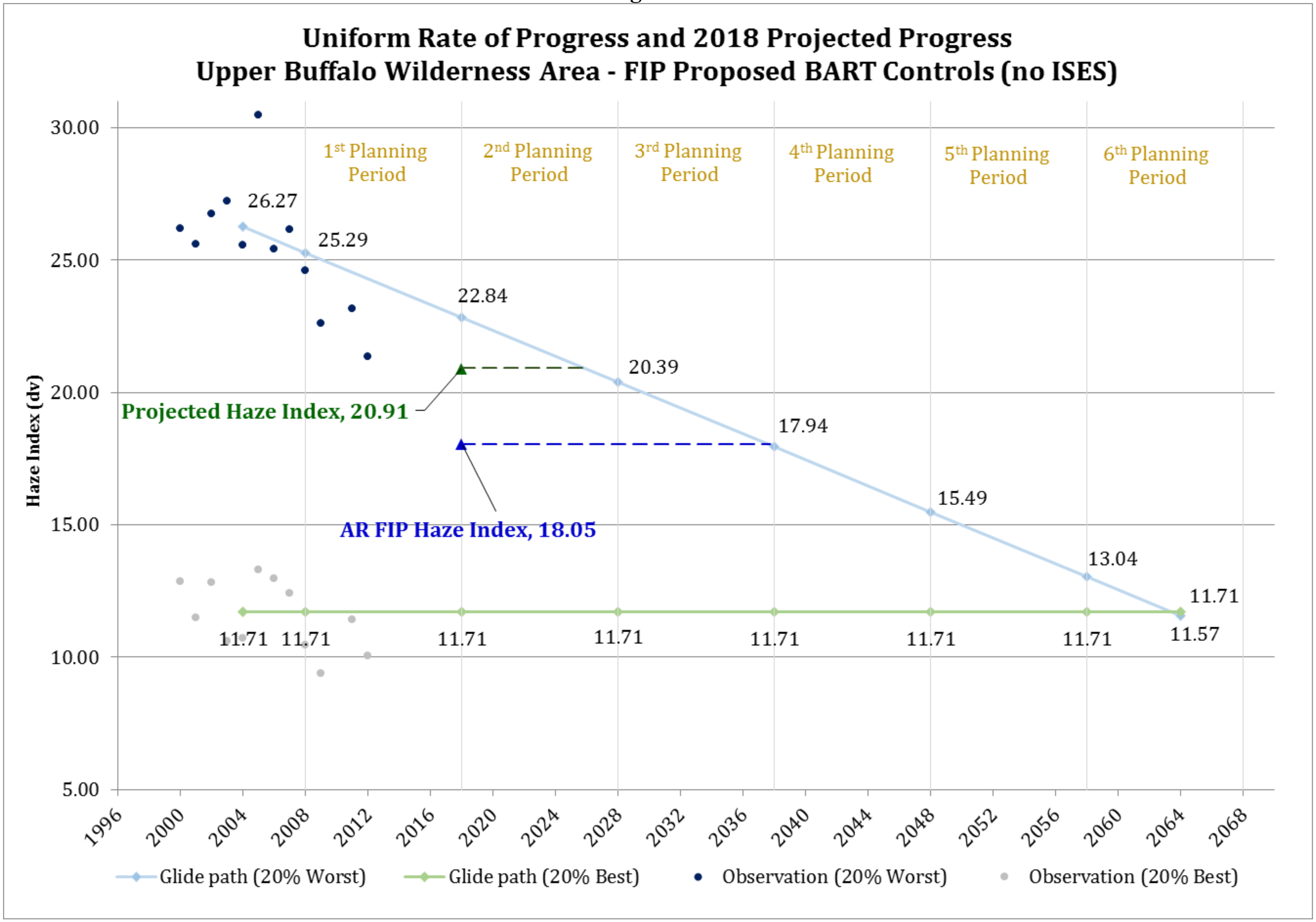
[38] The projected haze index at Upper Buffalo of 18.05 dv would keep Upper Buffalo below the glide path until approximately 2038 - the end of the third planning period. *See* Figure 12.

Figure 11



Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - FIP Proposed BART Controls (no ISES)
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
Projected Haze Index, 20.07
AR FIP Haze Index, 15.76
11.24
11.24
11.24
11.24
11.24
11.24
11.24
11.24
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

Figure 12


Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - FIP Proposed BART Controls (no ISES)
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
Projected Haze Index, 20.91
AR FIP Haze Index, 18.05
11.71
11.71
11.71
11.71
11.71
11.71
11.71
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)

If EPA insists on relying on CALPUFF to evaluate the projected visibility benefits of requiring controls on Independence, it must be consistent and use CALPUFF to evaluate the need for such controls for purposes of demonstrating reasonable progress. As demonstrated in Figures 11 and 12, controls at Independence cannot be justified for reasonable progress based on the CALPUFF results, which predict an improvement of several deciviews solely from BART controls.

(iii) Controls on Independence will not yield perceptible visibility benefits.

As demonstrated above, EPA's CALPUFF modeling greatly overstates the visibility benefits that would result from installing controls at Independence and should be disregarded. Further, when EPA used the CENRAP model (an appropriate multi-source model) to assess overall visibility impairment, EPA concluded that the cumulative benefit of installing all of the controls in the Proposed FIP – all BART controls plus controls at Independence – would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv. 80 Fed. Reg. at 18,998, Table 67. Since Independence represents only approximately 36% of the SO_2 point source emissions and 21% of the point source NOx emissions in Arkansas, *see id*. at 18,991, one can ascribe only a minor portion of this projected insignificant deciview improvement to controls on Independence (approximately **0.08** dv at Caney Creek and **0.07** dv at Upper Buffalo).[39] Based on this, installation of controls on Independence will yield no discernible visibility improvements.

Not only does this demonstrate the illogic of relying on CALPUFF for reasonable progress, it demonstrates that the realistic benefits resulting from installing controls at Independence will be inconsequential and will contribute virtually nothing to visibility improvement at either Class I area. According to EPA, one deciview reflects "perceptible changes" in visibility. *See* Proposed Regional Haze Rule, 62 Fed. Reg. 41,138, 41,145 (July 31, 1997) ("A one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in mandatory Class I Federal areas."). Thus, the measure of visibility improvement is based on *noticeable changes*. By EPA's own standard, a total deciview improvement at Caney Creek of 0.21 dv from the installation of controls at all of the proposed FIP sources would not be perceptible to the human eye. Likewise, a total deciview improvement at Upper Buffalo of 0.19 dv would not be discernable. Independence's contribution to the deciview improvements EPA projects based on the CENRAP modeling would be much less; nowhere close to the 1.95 dv and 1.78 dv improvement that EPA is claiming based on CALPUFF.[40] Requiring imperceptible visibility improvements is simply unreasonable. The

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[39] These values are the calculated improvement based on EPA's "scaling methodology." *See* 80 Fed. Reg. at 18,997.

[40] Even if the CALPUFF results were accurate, it is highly unlikely that such improvements would be perceptible. Studies have demonstrated that not only is the deciview scale not uniform in perception over a wide range of visibility conditions, but a 1-deciview change in visibility is not even perceptible to the human eye. *See* Exhibit E, *Just-Noticeable Differences in Atmospheric Haze*, Ronald C. Henry, Department of Civil and Environmental Engineering, University of Southern California, Los Angeles, Air & Waste Manage. Assoc. (2002). Instead, according to the Study, deciview improvements likely would need to be in the range of 2 to 5 dv to be perceptible. *Id*. at 1242, Figure 2.

CAA requires only "reasonable progress, not the *most* reasonable progress." *North Dakota v. EPA*, 730 F.3d 750, 767 (8th Cir. 2013).

In addition, the demonstration methodology used by EPA is unscientific. EPA used a ratio of emission rates from BART sources to Arkansas point sources to scale the modeled predicted haze index. First, there is no evidence to prove that the CAMx predicted modeling results are linearly correlated with emission rates. In fact, the CAMx modeling fundamentally is based on photochemical reactions. Therefore, the relationship between variation in the emission rates and predicted concentration is complicated. *See Chemical Characteristics of Inorganic Ammonium Salts in $PM_{2.5}$ in the Atmosphere of Beijing (China)*, A. Ianniello, F. Spataro, G. Esposito, I. Allegrini, M. Hu, and T. Zhu, 11 Atmos. Chem. Phys., at 10804 (2011).[41] For example, due to a high chemical affinity, an ammonia molecule reacts with SO_2 molecules to form sulfate before reacting with NOx molecules to form nitrate. If abundant SO_2 is present in the atmosphere, any increase in NOx emissions will not result in a linear increase in nitrate formation. As a result, there may not be any increase in the predicted regional haze. On the contrary, if abundant NOx molecules are present, then any reduction in SO_2 molecules will not result in a significant reduction in haze as NOx will substitute the reduced SO_2 in the reaction. Second, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in the visibility perceptible to a human observer. *See* 40 C.F.R. § 51.301 (definition of "deciview"). As such, deciviews cannot be added or subtracted directly. Therefore, fractioning or scaling deciviews based on emission rates is illogical.

(iv) EPA has offered no justification for requiring controls to achieve reasonable progress for this planning period when the controls cannot even be installed until the next planning period.

EPA further exceeds its authority by proposing to require controls in the name of achieving reasonable progress during the first planning period even though the emissions reductions the Agency proposes would not be achieved until well into the second planning period. The Proposed FIP covers a planning period of 2008-2018. The major SO_2 emissions control technology that would have to be installed at Independence to meet the proposed SO_2 emission rate limitation cannot be designed, constructed and operational in less than five years.[42] Given the likely effective date of the FIP in 2016, SO_2 controls at Independence could not be installed and operational before sometime in 2021.[43]

Adopting a reasonable progress goal for the first planning period based on the installation of controls that will not be completed until well after the deadline to achieve that reasonable progress goal makes no sense, and EPA has completely failed to explain why it is appropriate. Indeed, EPA will have multiple bites at this apple – there are still four more planning periods

[41] Available at http://www.atmos-chem-phys.net/11/10803/2011/acp-11-10803-2011.pdf.

[42] EPA recognizes this timeframe is necessary for the installation of SO_2 controls at Independence by proposing that Independence meet the SO_2 emissions limits no later than five years after the effective date of the final rule. 80 Fed. Reg. at 18,994. Entergy agrees with EPA's conclusion that a five-year timeframe would be necessary for the installation of controls at Independence.

[43] The Proposed FIP provides for NOx emission limitations to be met three years after the effective date of the FIP, which would not be earlier than sometime in 2019.

during which the necessity of reasonable progress controls can be evaluated. Controls on Independence should not be considered until these subsequent planning periods, and should not be imposed for a planning period that will have ended by the time any emissions reductions can be achieved at Independence. This is consistent with EPA's Reasonable Progress Guidance: "It is reasonable for [a state] to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal." Reasonable Progress Guidance at 1-4.

3. The proposed controls are not cost effective.

EPA's secondary justification for imposing controls on Independence is that it is, in EPA's opinion, cost effective to do so. 80 Fed. Reg. at 18,994-97. First, EPA's cost analysis for the proposed controls at Independence relies upon the control cost analysis for White Bluff, *see* SO_2 Cost TSD at 16, which is inappropriate. By simply relying on its White Bluff cost analysis without undertaking a site-specific analysis for Independence, EPA did not follow the steps necessary to identify the costs of controls for reasonable progress purposes. EPA's Reasonable Progress Guidance requires that EPA (1) identify the emissions units to be controlled; (2) identify the design parameters for the controls; and (3) develop cost estimates based upon those design parameters. Reasonable Progress Guidance at 5-1.

Second, even if the White Bluff cost analysis were sufficiently indicative of the costs to install controls at Independence, Entergy disagrees with EPA's estimated costs for the installation of dry scrubbers at White Bluff. *See* Section III.A.2 above. Assuming that dry FGD controls at Independence would cost the same as at White Bluff, the controls at Independence also would cost over $1 billion. *See* Section III.A.3 above. This is not cost effective on a $/ton basis for reasonable progress purposes as it would result in $4,234 per ton of SO_2 removed at Independence Unit 1 and $3,909 per ton of SO_2 removed at Independence Unit 2.

Finally, even if EPA's cost analysis as detailed in the SO_2 Cost TSD were correct, EPA's determination that the controls are cost effective is an insufficient basis to conclude that they must be installed for reasonable progress purposes.

(i) Requiring over $1 billion in controls at Independence to achieve an unnecessary and imperceptible change in visibility at Arkansas' Class I areas is patently unreasonable.

Despite the flaws in EPA's analysis of Entergy's costs, EPA concludes that dry FGD is cost effective at $2,477 per ton of SO_2 removed for Independence Unit 1 and $2,286 per ton of SO_2 removed for Unit 2. 80 Fed. Reg. at 18,994. Dry FGD is not cost effective for reasonable progress controls. These costs are higher than other cost per ton thresholds in RPG determinations in EPA-approved SIPs. The Kentucky Regional Haze SIP, 76 Fed. Reg. 78,194, 78,206 (Dec. 16, 2011), used $2,000 per ton SO_2 as a screening threshold for cost effectiveness based on CAIR. In the North Carolina Regional Haze SIP, 77 Fed. Reg. 11,858, 11,870 (Feb. 28, 2012), EPA approved the state's decision not to implement reasonable progress controls due to limited improvement in visibility even though cost effectiveness values were described as ranging "from 912 to 1,922 dollars per ton of SO_2 removed ($/ton SO_2), and the average costs per utility system ranged from $1,231 to $1,375/ton SO_2." EPA's estimated cost effectiveness of dry FGD at Independence is significantly higher than these thresholds, at $2,477/$SO_2$ ton removed for Unit 1 and $2,286/$SO_2$ ton removed for Unit 2. 80 Fed. Reg. at 18,994. Further, EPA has indicated that control costs found to be reasonable in the BART context may nonetheless be considered too costly in the reasonable progress context. *See* Final North Dakota SIP Approval/Disapproval, 77 Fed. Reg. 20,894, 20,936 (Apr. 6, 2012) (accepting North Dakota's determination that a level of $2,593 per ton of SO_2 removed was not reasonable and too costly in the reasonable progress context even though it is within the range EPA "ha[s] considered reasonable in the BART context"). Despite these prior actions, EPA unreasonably concludes that the proposed controls at Independence are cost effective for reasonable progress purposes.

Additionally, EPA failed to consider the cost effectiveness of the controls relative to the visibility benefit that would result. EPA's own guidance notes that for "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation." Reasonable Progress Guidance at 5-2. Here, EPA gave no consideration to the dollar-per-deciview resulting from installing scrubbers at Independence. If EPA had done so, it would recognize that the costs are approximately **$1.33 billion** per dv improvement at Caney Creek and **$1.53 billion** per dv improvement at Upper Buffalo. *See* S&L FIP Cost Report at 21, Table 8. Where additional visibility improvement is not needed to remain below the glide path, such an exorbitant cost cannot be justified. *See Nat'l Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1149 (9th Cir. 2015) ("*NPCA*") (upholding EPA's decision not to require reasonable progress controls because of lack of cost-effectiveness, finding reasonable EPA's explanation that "cost of compliance is only one of the four statutory requirements for reasonable progress analysis.").

(ii) EPA inappropriately revised Entergy's control cost analysis by eliminating consideration of proper costs.

EPA's cost estimates are artificially low because they fail to account for key considerations. As discussed above in Section III.A.2, EPA unjustifiably revised important aspects of Entergy's Revised White Bluff BART Analysis, upon which the reasonable progress controls cost analysis for Independence is based. At the least, EPA must re-evaluate the costs of controls based upon the 2015 S&L FGD Cost Estimate, attached as Exhibit B.

As discussed in Section III.A.3 above, S&L estimated that the costs of dry FGD at White Bluff Units 1 and 2 would be over $1 billion, which is approximately 220% higher than EPA's estimate. Based on the 2015 S&L FGD Cost Estimate, and assuming a 30-year life for the dry FGD systems at Independence and identical costs, this results in an average cost effectiveness at Independence Unit 1 of $4,234 and of $3,909 at Independence Unit 2, which, as noted above, is much higher than cost per ton thresholds EPA rejected for reasonable progress determinations in other states. As importantly, the cost per deciview improvement that would result from installing these controls is estimated at approximately $1.33 billion at Caney Creek and $1.53 billion at Upper Buffalo. *See* S&L FIP Cost Report at 21, Table 8. Such a massive investment cannot be justified in light of the continuous improvement in visibility being achieved at both Caney Creek and Upper Buffalo.

D. EPA Should Adopt Entergy's Proposed Alternative Approach For White Bluff And Independence.

EPA has requested public comment on any alternative SO_2 and NOx control measures that would address the regional haze requirements for White Bluff Units 1 and 2 and Independence Units 1 and 2 for this planning period. 80 Fed. Reg. at 18,997. According to EPA, this includes, but is not limited to, a combination of early unit shutdowns and other emissions control measures at the four units that would achieve *greater* reasonable progress than the BART and reasonable progress requirements that EPA has proposed for the first planning period. *See id.*

1. EPA has no legal basis for requiring that a four-unit approach achieve greater reasonable progress.

EPA has offered no legal basis for its claim that an alternative four-unit approach must achieve *greater* reasonable progress than the controls that EPA has proposed, 80 Fed. Reg. at 18,997, and Entergy disagrees that such a requirement is applicable or mandated by the Clean Air Act or EPA's own Regional Haze Rule. Neither the Act nor EPA's rules impose such a requirement. To the contrary, EPA noted in the final Regional Haze Rule that states have discretion to determine what control measures must be implemented to achieve reasonable progress. 64 Fed. Reg. at 35,721. EPA further explained that "States may conclude that control strategies specifically for protection of visibility are not needed at this time because the analyses may show that existing measures are sufficient to meet reasonable progress goals." *Id.* Indeed, not only is it up to the states to determine how much must be done to ensure reasonable progress, but states conceivably could conclude that *nothing* must be done. There is no provision setting a "floor" for reasonable progress.[44]

2. Entergy's proposed approach achieves virtually identical visibility benefits as the Proposal for over $2 billion less.

Entergy is proposing near-term interim controls and the cessation of coal combustion at White Bluff by 2028. Entergy also is proposing to meet lower SO_2 emission rates at all four units by 2018, and proposes to install LNB/SOFA at all four units and meet a 30-day rolling average NOx emission rate of 1,342.5 lb NOx/hr, within three years after the effective date of the final FIP.[45] This combination of controls and lower SO_2 emission rates will ensure that the Class I areas achieve virtually the same reasonable progress as EPA's Proposal but at a cost of over $2 billion less than the Proposal. *See* Figures 13 and 14 below, which compare the projected 2018 haze index at each Arkansas Class I area based on the Ranked Statistical Analysis, to the

[44] While states that opt to implement an emissions trading program or other alternative measure rather than require sources to install, operate, and maintain BART *are* required to demonstrate that this alternative will achieve greater reasonable progress than would be achieved through the installation of source-specific BART, 40 C.F.R. § 51.308(e)(2), Entergy is not proposing a BART alternative. Rather, under Entergy's four-unit approach, the NOx control measures and lower SO_2 emission rate proposed for White Bluff would constitute BART for White Bluff while the NOx control measures and lower SO_2 emission rate proposed for Independence are more than sufficient for reasonable progress purposes for this planning period.

[45] Entergy's rationale for the proposed NOx rate is discussed in Section III.E. below.

deciview improvements projected for the following scenarios (1) Entergy's proposed controls, based on the cessation of coal-fired operations at White Bluff (referred to as "WB") and the installation of LNB/SOFA and lower SO_2 emission rate at Independence (referred to as "ISES"); and (2) installation of the Proposed FIP controls at all BART sources and Independence. Based on Entergy's modeling, the difference in the haze index between the proposed FIP controls and Entergy's proposal is 0.05 dv at Caney Creek and 0.07 at Upper Buffalo; differences that are too trivial to justify a $2 billion investment at White Bluff and Independence for the installation of dry FGD.

Figure 13

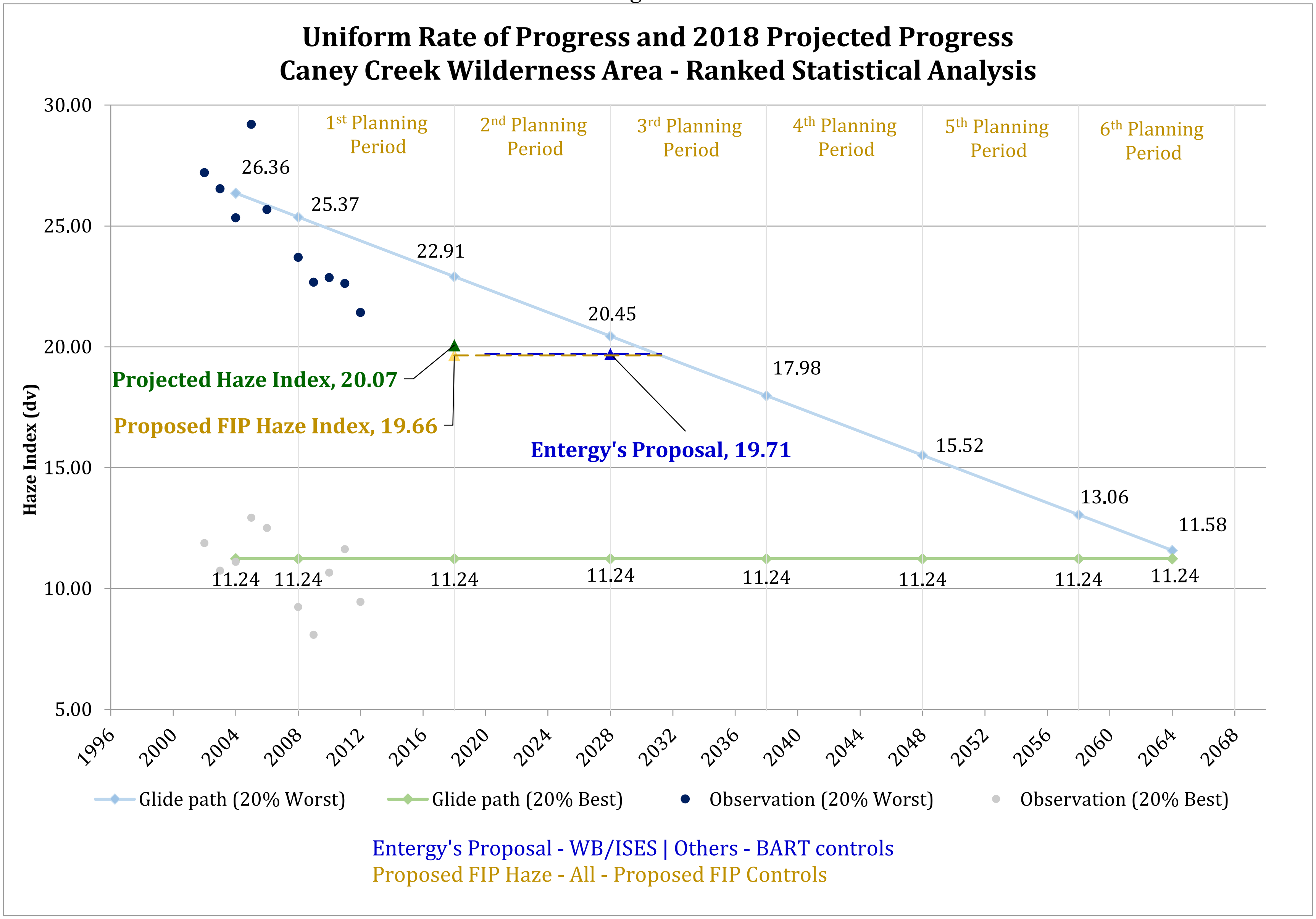
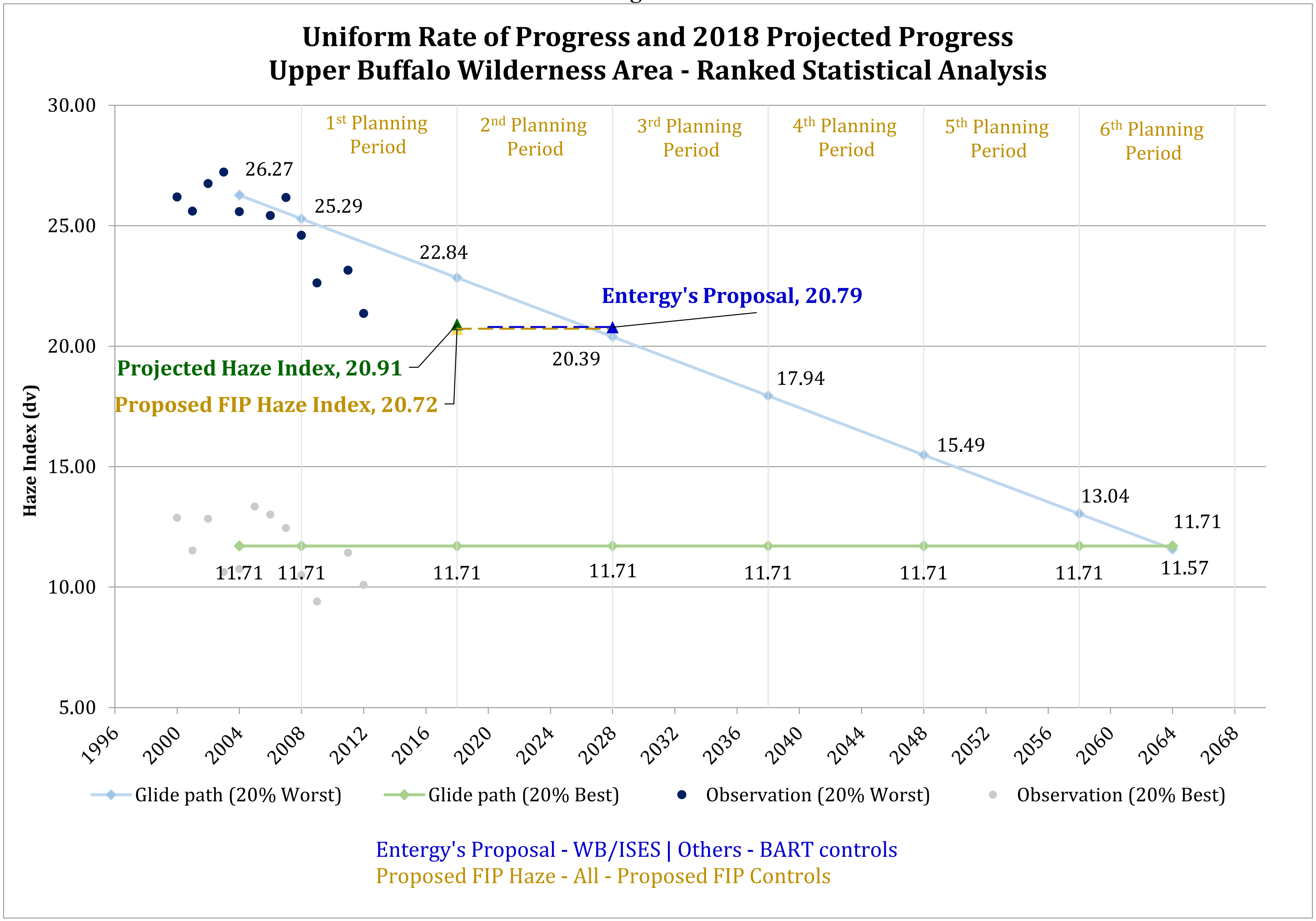

Uniform Rate of Progress and 2018 Projected Progress
Caney Creek Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.36
25.37
22.91
20.45
17.98
15.52
13.06
11.58
11.24
Projected Haze Index, 20.07
Proposed FIP Haze Index, 19.66
Entergy's Proposal, 19.71
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls

Figure 14



Uniform Rate of Progress and 2018 Projected Progress
Upper Buffalo Wilderness Area - Ranked Statistical Analysis
Haze Index (dv)
30.00
25.00
20.00
15.00
10.00
5.00
1996
2000
2004
2008
2012
2016
2020
2024
2028
2032
2036
2040
2044
2048
2052
2056
2060
2064
2068
1st Planning Period
2nd Planning Period
3rd Planning Period
4th Planning Period
5th Planning Period
6th Planning Period
26.27
25.29
22.84
20.39
17.94
15.49
13.04
11.71
11.57
11.71
Entergy's Proposal, 20.79
Projected Haze Index, 20.91
Proposed FIP Haze Index, 20.72
Glide path (20% Worst)
Glide path (20% Best)
Observation (20% Worst)
Observation (20% Best)
Entergy's Proposal - WB/ISES | Others - BART controls
Proposed FIP Haze - All - Proposed FIP Controls

Entergy's proposed approach with respect to White Bluff and Independence makes sense in light of the long-term objectives of the Regional Haze Program, the high capital costs for scrubbers, and the significant long-term environmental co-benefits from the cessation of coal-firing at the White Bluff units. Arkansas' Five-Year Progress Report demonstrates that the state currently is below the glide path for Caney Creek and Upper Buffalo, and expects to remain so through at least 2018. *See* Section III.C.1 above. Entergy's approach would help ensure that Arkansas remains below the glide path throughout the second planning period, and will produce very large additional reductions in NOx, SO_2, and PM heading into the third planning period.

Ultimately, Entergy's approach would achieve more than 170,000 tons of NOx reductions from White Bluff than the proposed FIP would achieve. While scrubbers would reduce SO_2 emissions substantially, the total visibility benefits from ceasing to use coal are at least as great. Entergy's approach also would achieve multi-pollutant co-benefits. Prior to 2028, SO_2 and NOx would be reduced, which would result in reductions in ozone and $PM_{2.5}$. Starting in 2028, Entergy's approach would produce even greater reductions in emissions of SO_2, NOx and $PM_{2.5}$, as well as achieving reductions in mercury and other hazardous air pollutants, and CO_2/CO_2e. It would reduce annual greenhouse gas emissions by approximately 11.74 million tons per year, a 275 million ton lifetime benefit over EPA's Proposal. Additionally, the elimination of coal combustion in 2027 and 2028 would reduce rail and truck traffic, allow for the closure of landfills, and reduce water usage, in addition to other environmental benefits.

3. EPA should adopt RPGs for Arkansas that reflect Entergy's proposal.

Entergy opposes the RPGs that EPA has proposed for Caney Creek and Upper Buffalo. The RPGs reflect the approved portions of Arkansas' Regional Haze SIP, the proposed FIP BART controls, and the controls proposed for Independence. 80 Fed. Reg. at 18,997. For all of the reasons discussed above in Section III.C, controls at Independence for reasonable progress purposes are not justified and including the emissions reductions based on the installation of dry FGD and LNB/SOFA at Independence renders EPA's RPGs arbitrary and capricious. EPA should recalculate the RPGs based on Entergy's proposed approach for controlling emissions at White Bluff and Independence.

E. The Proposed NOx Limits For White Bluff And Independence Cannot Be Achieved Based On The Plants' Current Operating Conditions.

The NOx emission limits proposed by Entergy for the units at White Bluff and Independence are based on the emission rate for LNB/SOFA of 0.15 lb/MMBtu that Entergy proposed in the Revised White Bluff BART Analysis. At the time Entergy submitted the Revised White Bluff BART Analysis in October 2013, all four of the coal-fired units at White Bluff and Independence were operated as base load units and spent the overwhelming majority of their operating time at loads of greater than 50% of unit capacity. Since submitting the Revised White Bluff BART Analysis,[46] Entergy transitioned to MISO in December 2013. MISO utilizes an economic dispatch model to determine which EGUs within its service territory are

[46] Entergy notes that EPA relied upon the Revised White Bluff BART Analysis to evaluate controls for Independence.

dispatched to operate and the operating load (MW) for each unit. Initially the MISO operating environment resulted in similar unit dispatch schedules for White Bluff and Independence, with all four units primarily dispatched as base-load units with some load-following operation. However, beginning in December 2014, the units at both White Bluff and Independence began to be dispatched primarily as load-following units. Since December 2014, the White Bluff and Independence units have been dispatched less frequently and, when dispatched, have spent significantly more time at low operating rates of less than 50% of unit capacity.

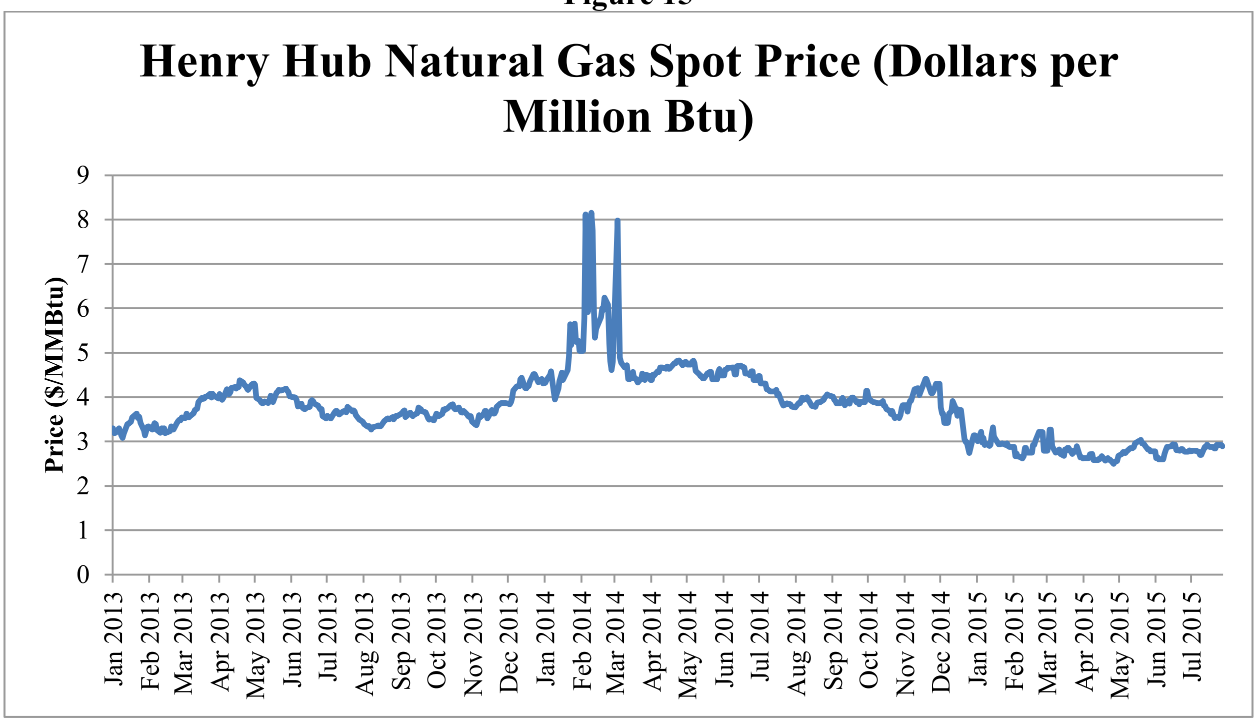
The impact of this change in dispatch of the units can be seen in the following table. The data for 2015 (through June 30) reflects a significant increase in the percentage of time that each unit is dispatched at less than 50% of operating capacity. Three of the four units have spent greater than 40% of their 2015 operating hours at less than 50% of capacity, and the two Independence units have spent nearly half of their operating time at less than 50% of capacity.

	WB1		WB2		ISES1		ISES2	
	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load	# of Hours <50% Load	% of Operating Hours <50% Load
2013	624	7.96%	606	7.95%	797	10.99%	979	11.60%
2014	959	12.39%	784	10.32%	818	10.39%	1069	13.69%
2015 (YTD)*	1444	42.84%	681	27.54%	1278	48.03%	1267	49.40%

* 2015 YTD represents Jan-June 2015

This change in dispatch coincided with a sharp drop in natural gas prices which can be seen in Figure 15 below. This drop in gas prices to near $3 per MMBtu has been sustained since December 2014, and Entergy has no reason to expect any significant increase in gas pricing in the near future.

Figure 15



This change in dispatch for the units at both White Bluff and Independence is significant with regard to NOx emissions as the LNB/SOFA system is designed to operate primarily in the range of 50-100% of unit load. Entergy has selected Foster Wheeler as the LNB/SOFA vendor for White Bluff and has only been able to obtain a guarantee of less than 0.15 lb/MMBtu for operating loads in the range of 50-100% of unit capacity.[47] Since the available emission guarantee does not cover unit operation at less than 50% of capacity, Entergy requested a memorandum from Foster Wheeler regarding the impact of unit operation at less than 50% capacity on NOx emission rates. This memorandum is attached as Exhibit G to these comments. Based on input from the LNB/SOFA vendor, Entergy does not believe that the proposed emission rate of 0.15 lb/MMBtu is consistently achievable under all operating conditions. Even with a 30-day averaging period for the proposed limit, a unit which is frequently dispatched at less than 50% of capacity may not be able to achieve compliance.

This was not perceived as an issue at the time that the Revised White Bluff BART Analysis was prepared and submitted to ADEQ by Entergy as, historically and at that time, the units were operated almost exclusively as base-load units and spent less than 10% of their operating time at less than 50% of unit capacity. In the current dispatch environment, with some units spending nearly 50% of their operating time outside of the control range for LNB/SOFA, Entergy can no longer be confident that the units will be able to achieve compliance with a limit of 0.15 lb/MMBtu on a 30-day rolling average basis.

The concern arises from low-load operation during which periods of higher NOx emissions, on a lb/MMBtu basis, would not be expected to correspond to an increase in the maximum mass emission rate (lb/hr) from the units as any increase in the emission rate on a lb/MMBtu basis would be expected to be more than offset by the lower unit operating rate in MMBtu/hr to arrive at a mass emission rate (lb/hr).

To address the potential for a higher NOx emission rate (lb/MMBtu basis) at operating rates of less than 50% of unit capacity, Entergy proposes a rolling 30-boiler operating day average emission rate of 1,342.5 lb NOx/hr at each coal-fired unit at White Bluff and Independence. In the alternative, if EPA believes that a lb/MMBtu limit is necessary for the units, Entergy proposes a bifurcated NOx emission limit for each unit at both White Bluff and Independence as follows.

> For all unit operation (0-100% of capacity), a limit of 1,342.5 lb NOx/hr, based on a rolling 30-boiler operating day average.
>
> And;

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[47] This range is referred to as the "control range" by Foster Wheeler. *See* Exhibit F, p. 46, for Foster Wheeler's emissions guarantee. The load ranges identified in the emissions guarantee equate to 50% to 100% of the White Bluff units' operating capacity. Entergy added .01 lb/MMBtu to Foster Wheeler's emissions guarantee to account for fluctuations in NOx emissions from the units. Controlled NOx emissions fluctuate during normal boiler operation in response to a number of design/operating parameters including, but not necessarily limited to: inlet NOx concentrations, boiler load, load changes, particulate matter loading, flue gas temperatures and flue gas velocities. A compliance margin above the vendor's emissions guarantee is recommended for establishing an enforceable limit to address such fluctuations.

For unit operation at 50-100% of capacity, a limit of 0.15 lb NOx/MMBtu, based on a rolling 30-boiler operating day average, to include only those hours for which the unit was dispatched at 50% or greater of maximum capacity.

This alternative approach would ensure that the units are operated in compliance with the LNB/SOFA design within the control range of 50-100% of capacity while providing Entergy with flexibility in demonstrating compliance. The lb/hr limit, which would apply to all operating hours, will ensure that the 30-day average emission rates remain below those on which both EPA and Entergy relied to project visibility improvements from the proposed NOx emission reductions.

F. The NOx BART Determination For Lake Catherine Unit 4 Should Be No Controls.

1. Visibility Improvement From Controls On Lake Catherine Unit 4 Cannot Be Reasonably Anticipated.

EPA has proposed NOx BART controls for Lake Catherine Unit 4 based on the installation of burners out of service ("BOOS"). *See* 80 Fed. Reg. at 18,978. To justify the visibility improvement resulting from installation of the proposed controls, EPA relied on the CALPUFF dispersion modeling system without assessing the reliability of the model to predict very small changes in visibility. In *NPCA*, the Ninth Circuit concluded that EPA had failed to justify that predicted visibility improvements were "reasonably anticipated," as required by the Clean Air Act, where the improvements were so insignificant that they were within the CALPUFF model's margin of error. *NPCA*, 788 F.3d 1134, 1146-47.

On behalf of Entergy, Trinity completed a quantitative analysis to evaluate the margin of error in the CALPUFF model for Lake Catherine Unit 4. As part of this analysis, Trinity modeled the following three scenarios:

- All BART – Includes all sources subject to BART, modeled using Pre-BART representations;
- Pre-BART – Includes only Lake Catherine Unit 4, modeled based on the current permit representation; and
- Post-BART – Includes only Lake Catherine Unit 4, modeled using Post-BART emission rate and stack parameters.

Trinity calculated the average difference between modeled values obtained using CALPUFF (including the CENRAP background) and IMPROVE monitored values for Caney Creek and Upper Buffalo for each of the three modeling scenarios. Trinity compared the regional haze design value format of average W20 days visibility for this analysis. Specifically the following comparisons were made:

- Modeled vs Measured W20 Days: The W20 days based on IMPROVE measurements were selected for each Class I area and compared with the CALPUFF results from the corresponding days.

- Measured vs. Modeled W20 Days: The W20 days based on CALPUFF modeling results were selected considering only days when IMPROVE measurements were taken. Modeled values were then compared to the IMPROVE measurements from the corresponding days.

- Measured and Modeled W20 Days: The W20 days based on IMPROVE measurements were selected and compared with the W20 days based on CALPUFF modeling disregarding temporal correlation.

A complete discussion of Trinity's analysis and results is presented in *Evaluation of the CALPUFF Modeling System Margin of Error for a BART Analysis, Entergy Services, Inc. - Lake Catherine Plant*, Trinity Consultants (Aug. 4, 2015). ("CALPUFF Margin of Error Report"), which is attached as Exhibit H and is hereby incorporated by reference. As demonstrated in the CALPUFF Margin of Error Report, the Pre-BART impact from Lake Catherine Unit 4 at Caney Creek and Upper Buffalo is inconsequential when compared with the IMPROVE measurements, which capture the impact of all other sources, including Lake Catherine, on the Class I areas.

The proposed NOx BART controls for Lake Catherine Unit 4 will result in visibility improvements that are even more inconsequential and cannot accurately be predicted by CALPUFF. Based on Trinity's analysis, the minimum calculated margin of error for CALPUFF for Lake Catherine Unit 4 is 0.93 dv. The CALPUFF predicted visibility improvement associated with EPA's proposed BART controls for Lake Catherine Unit 4 at Caney Creek and Upper Buffalo falls within this margin of error. *See* 80 Fed. Reg. at 18,978, Table 42. As such, the visibility improvements at each of these Class I areas associated with the proposed BART controls for Unit 4 cannot "reasonably be anticipated." 42 U.S.C. § 7491(g)(2); *see NPCA*, 788 F.3d 1134, 1146-47. Accordingly, EPA has not adequately demonstrated that it is appropriate to require NOx BART controls on Lake Catherine Unit 4.

2. Source-Specific Controls Should Not Be Imposed On Lake Catherine Unit 4.

If EPA finalizes a determination that Lake Catherine Unit 4 should be subject to NOx BART controls, EPA should not impose source-specific NOx controls on Lake Catherine Unit 4 but should instead find that CSAPR is better than NOx BART in Arkansas for all EGUs, as discussed in Section III.A.4 above. Compliance with CSAPR will ensure that NOx emissions from Arkansas' EGUs are limited and will improve visibility in Arkansas' Class I areas.

EPA also had evaluated controls other than BOOS for Lake Catherine Unit 4. *See* 80 Fed. Reg. at 18,976-78. Similar to BOOS, however, these controls would result in imperceptible visibility improvements in Arkansas' Class I areas. Although Entergy did not evaluate the margin of error with respect to the CALPUFF predicted visibility improvement from these other controls, EPA had rejected these controls as NOx BART for Lake Catherine Unit 4 based on costs and Entergy agrees with EPA's determination that these controls should not be considered as NOx BART for Lake Catherine Unit 4. Specifically, Entergy agrees with EPA that the incremental cost effectiveness of installing LNB/SOFA at Lake Catherine Unit 4 cannot be justified as BART. *See id*. at 18,978. Similarly, the installation of LNB/SOFA and selective non-catalytic reduction ("SNCR") or selective catalytic reduction ("SCR") cannot be justified as

BART based on either average cost effectiveness or incremental cost effectiveness. *Id*. Lake Catherine Unit 4 is a peaking unit and operated at only a two percent capacity factor in 2014. [48] The estimated incremental costs of installation of LNB/SOFA (at $14,246/ton), SNCR (at $16,029/ton), and SCR (at $11,767/ton) are simply not warranted for a unit that operates so infrequently. *See id.* at 18,978. Installation of these controls would require a massive capital investment and significant operation and maintenance costs that are impracticable for a peaking unit.

G. EPA Improperly Considered The Cumulative Visibility Improvement At All Class I Areas.

EPA's reliance on a "cumulative visibility improvement" metric is arbitrary and capricious, and has no basis in law. In assessing the visibility improvements that are predicted to be achieved through the installation of proposed controls at White Bluff, Lake Catherine, and Independence, EPA totaled the predicted improvements at all affected Class I areas to yield a cumulative visibility improvement associated with each facility. *See* 80 Fed. Reg. at 18,972 (Tables 34 and 35); 18,974 (Tables 37 and 38); 18,978 (Table 42); 18,994 (Table 64). EPA appears to have relied upon the cumulative visibility improvement across the four affected Class I areas to support its proposed NOx BART determination for Lake Catherine. 80 Fed. Reg. 18,978 (where EPA identified the cumulative visibility impact in its rationale for the Lake Catherine "Proposed NOx BART Determination"). It is improper for EPA to rely upon the cumulative visibility improvement across all affected Class I areas. BART and reasonable progress determinations instead should be based on the predicted visibility improvements at individual Class I areas.

The preamble to the BART Guidelines states that the focus of an analysis of visibility improvements associated with BART controls is to be on the "nearest Class I area" to the facility in question. 70 Fed. Reg. 39,104, 39,170 (July 6, 2005) ("One important element of the [modeling] protocol is in establishing the receptors that will be used in the model. The receptors that you use should be located in the *nearest* Class I area with sufficient density to identify the likely visibility effects of the source.") (emphasis added). While the Rule allows consideration of impacts at other nearby Class I areas, it is for the purpose of "determin(ing) whether effects at those areas *may be greater than* at the *nearest* Class I area." *Id.* (emphasis added). Summing the predicted visibility improvements at multiple Class I areas does not facilitate a determination that effects at more distant Class I areas are more significant than those at the closest Class I area.

In addition to having no basis in EPA's own regulations, the cumulative metric is deceptive and provides no information that could be used to assess whether any single Class I area would experience perceivable visibility improvements as a result of BART or reasonable progress controls. For example, EPA appears to have selected BOOS as NOx BART for Lake Catherine in part because it would achieve a cumulative visibility improvement across the four affected Class I areas of 1.215 dv. 80 Fed. Reg. at 18,978. But the cumulative metric masks the

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[48] Entergy's current resource planning assumption is that Lake Catherine Unit 4 will be de-activated in mid-2025, though no final decision to this effect has yet been made.

fact that no individual Class I area would experience any discernible visibility improvement. Instead, Mingo would experience a 0.196 dv improvement, Hercules-Glades would experience a 0.175 dv improvement, Upper Buffalo would experience a 0.248 dv improvement, and Caney Creek would experience a 0.596 dv improvement. *See id.* These are imperceptible levels of improvement that do not justify installation of controls.[49] The metric therefore equates imperceptible visibility "benefits" in different areas with a much larger and indisputably discernible visibility improvement in a single area.

On a practical level, reliance on a cumulative visibility improvement is illogical. Deciview improvements at multiple areas cannot be added together to form a meaningful metric. As discussed in Section III.C.2 above, a deciview is a logarithmic scale based on the concept that one deciview is the minimum change in visibility perceptible to a human observer. Deciviews cannot be directly added or subtracted. To add or subtract the haze, one must add or subtract the total extinction values and then recalculate the haze index in deciviews. Considering the Class I areas addressed in the Proposal are hundreds of kilometers away from each other, particles from one Class I area cannot contribute to or improve the light extinction at another Class I area, therefore, adding or subtracting light extinction values is not an accurate representation of reality and would be illogical. In simple terms, a visitor to a Class I area cannot benefit from any visibility improvement that might be occurring at another Class I area. The cumulative metric represents an illusory visibility benefit; it is an improvement that cannot be perceived and therefore provides no indication of whether the proposed controls will contribute to the goal of the Regional Haze Program: to reduce human perception of visibility impairment in Class I areas. This cumulative visibility metric should be eliminated from any consideration of whether proposed controls will result in visibility improvement, including for the Lake Catherine BART analysis.

H. EPA Must Address The Requirements Of Executive Orders 12866 And 13211.

EPA claims that the Proposal is not a "significant regulatory action" under Executive Order 12866. 80 Fed. Reg. at 18,999. Entergy disagrees. The Proposal's implementation cost to EAI alone of over $2 billion exceeds the $100 million threshold for economic significance. "By virtue of [the] longstanding Executive Order [12866] applying to significant rules issued under the Clean Air Act (as well as other statutes), the Agency must systematically assess the regulation's costs and benefits." *Michigan v. EPA*, 135 S.Ct. at 2715 (Kagan, J. dissenting). EPA states that the Proposal is not generally applicable, and therefore not subject to Executive Order 12866, because the rule "only proposes source specific requirements for particular, identified facilities (six total)." 80 Fed. Reg. at 18,999. However, a count of the number of entities regulated under a rule is not indicative of the general applicability or the significance of the economic impacts of the rule. Requiring additional controls at power plants initiates a cascade of impacts, including changes in the regional distribution of electricity and rates of thousands of electricity customers in multiple states. These far-reaching impacts merit

[49] As discussed above in Section III.F.1, EPA did not perform an analysis to confirm that the model predictions are not within the model's margin of error and, therefore, EPA has not justified that the predicted visibility improvements are "reasonably anticipated."

classifying the Proposed FIP as a regulation with general applicability and significant economic impact.

Entergy also disagrees with EPA's conclusion that the Agency is not required to assess the energy impacts of the Proposed FIP under Executive Order 13211. 80 Fed. Reg. at 19,000. The Proposal will have a significant impact on the supply, distribution, and use of energy. Installation of additional controls will require outages at multiple power plants, altering the normal supply and distribution of energy. Additionally, the more than $2 billion cost of implementing the Proposed FIP will be imposed upon EAI's customers and co-owners, impacting energy use as electricity rates climb.

EPA must prepare a cost/benefit analysis and evaluate the energy impacts of the Proposed FIP and issue these analyses for public comment before finalizing the FIP.

I. Additional Comments.

- Entergy agrees with EPA's proposal that the existing emission limits at the White Bluff Auxiliary Boiler satisfy BART for SO_2, NOx, and PM. 80 Fed. Reg. at 18,975.

- Entergy agrees that 2009-2011 should be used as the baseline period for NOx for White Bluff Units 1 and 2. 80 Fed. Reg. at 18,969.

- If EPA finalizes a source-specific NOx BART limit for Lake Catherine Unit 4, Entergy requests that EPA confirm that the unit may continue to conduct monitoring pursuant to 40 C.F.R. Part 75 Appendix E so long as it qualifies as a peaking unit. In the Proposal, EPA appears to have assumed that Unit 4 currently operates "full" NOx CEMS with a continuous NOx analyzer pursuant to 40 C.F.R. Part 60. However, because Unit 4 meets the definition of a peaking unit under 40 C.F.R. Part 75, and the unit is not subject to any NSPS Part 60 standards, Entergy does not currently operate a NOx analyzer for the unit. Under Part 75, Unit 4 qualifies as an Appendix E unit, allowing the unit to utilize a NOx correlation curve to estimate emissions and only monitor heat input and exhaust O_2 concentration.

- Entergy agrees with EPA's conclusion that wet scrubbers do not constitute BART for White Bluff and should not be installed at Independence to meet reasonable progress requirements. 80 Fed. Reg. at 18,972, 18,993.

- Entergy agrees with EPA that LNB/SOFA/SNCR or LNB/SOFA/SCR cannot be justified as BART for White Bluff based on the incremental cost effectiveness of the controls. 80 Fed. Reg. at 18,974.

- Entergy disagrees that the proposed regional haze FIP will satisfy the requirements of CAA Section 110(a)(2)(D)(i)(II), 80 Fed. Reg. at 18,998, for the reasons explained in Entergy's comments on EPA's proposed disapproval of Arkansas' SIP revision addressing interference with other states' programs for visibility protection for the 2006 revised 24-hour $PM_{2.5}$ NAAQS. These comments are attached as Exhibit I and are hereby incorporated by reference.

IV. CONCLUSION

Entergy appreciates the opportunity to comment on the Proposed FIP. Entergy strongly urges EPA to adopt a comprehensive approach to regional haze that would involve the four coal-fired units at Independence and White Bluff, as Entergy as proposed, without requiring expensive, unnecessary scrubber technology. Such an approach would ensure superior, long-term visibility benefits than would the Proposed FIP. It also would deliver important non-haze environmental benefits, including a dramatic decrease in GHG emissions, large reductions in SO_2 emissions that also contribute to long-range $PM_{2.5}$ issues, and large reductions in ozone (and $PM_{2.5}$)-forming NOx emissions. Entergy respectfully requests that EPA amend the Proposed FIP as described in these comments.

Respectfully submitted,

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Assistant General Counsel – Environmental (Lead)
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ENTERGY ARKANSAS, INC.

REVIEW OF EPA'S COST ANALYSIS FOR ARKANSAS REGIONAL HAZE PROPOSED FEDERAL IMPLEMENTATION PLAN

SL-012913
Final

July 14, 2015

Project No: 13027-002

PREPARED BY

Sargent & Lundy LLC

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TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY

On April 8, 2015, the U.S. Environmental Protection Agency (EPA) published in the *Federal Register* a proposed rule that would partially approve and partially disapprove specific portions of the Arkansas State Implementation Plan (AR SIP) and issue a Federal Implementation Plan (FIP) that would regulate a group of Arkansas electric generating units (EGUs).[1] In this rule, EPA proposes to require additional SO_2 emission reductions that would require retrofitting new FGD systems on Entergy's White Bluff Station Units 1 and 2 and Entergy's Independence Station Units 1 and 2.

Sargent & Lundy (S&L) was contracted by Entergy to review EPA's proposed cost modifications as described in its Technical Support Document entitled, "Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan," hereinafter referred to as "FIP TSD," including one if its appendices, entitled "Appendix A. Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plant (SO_2 Cost TSD)," hereinafter referred to as "Cost TSD."

Cost-effectiveness is influenced by two variables: the total annualized cost to retrofit dry FGD systems ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable.

Based on our review, the following items in EPA's analysis were identified to result in overstating the tons of SO_2 removed:

- After defining a baseline SO_2 emission period of between 2009 and 2013, EPA arbitrarily excluded the years with the maximum and minimum annual averages;
- When calculating SO_2 emission reductions due to FGD retrofits, EPA incorrectly used maximum monthly averages for baseline SO_2 emissions; and
- A controlled SO_2 limit of 0.06 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities.

In addition, the following items in EPA's analysis were identified to result in understating the annualized cost of the dry FGD retrofit:

- EPA subtracted over $23 million in BOP costs for both units because they mistakenly believed the equipment to be included in Alstom's scope;
- Because EPA mistakenly removed BOP cost items that should be included in the estimate, they over-estimated and misapplied percent reductions to other cost items, resulting in cost subtractions of over $7 million for both units;

[1] *See* 80 Fed. Reg. 18,944 (April 8, 2015).

- EPA removed over $41 million per unit in Owner's Costs despite the fact that these are real costs that the Entergy will incur;
- EPA under-estimated cost escalation, and in some cases de-escalated costs, by relying on cost indices rather than using vendor pricing information, all of which resulted in under-estimating costs by more than $42 million per unit;
- EPA incorrectly utilized the IPM model, which is not designed to evaluated site-specific costs, to verify O&M costs at White Bluff;
- EPA scaled capital costs to a design fuel of 0.68 lb/MMBtu, which when compared to operating data, is completely insufficient to ensure compliance with the proposed emission limits for nearly half of the time;
- While we agree that O&M costs should be based on 0.68 lb/MMBtu, EPA's methodology to scale direct O&M costs based on fuel sulfur levels is incorrect and resulted in under-estimating these costs by over $5 million per unit;
- EPA incorrectly scaled indirect O&M costs using fuel sulfur levels, despite these costs being estimated as percentages of capital cost, which resulted in under-estimating these costs by over $4 million; and
- EPA used a remaining useful life of 30 years, when Entergy is proposing to cease coal-fired operations on these units in 2027 and 2028, resulting in a remaining useful life of 6 or 7 years.

As discussed above, S&L's analysis reveals that EPA overstates the cost-effectiveness ($/ton of SO_2 removed) to retrofit dry FGD systems at White Bluff Units 1 and 2, which EPA proposes to require in its FIP. In its approach, EPA understated the annualized cost of the control systems and overstated the tons of SO_2 that would be removed by its FIP-imposed FGD retrofits. To better address EPA's questions on scope and cost items which it did not understand, S&L has prepared an updated cost report to clarify and provide further detail around scope items and cost items included in the estimate.[2] The corrected and updated cost-effectiveness for both White Bluff units is greater than $7500/ton, which is clearly not cost effective.

With respect to EPA's Reasonable Progress Goal (RPG) analysis for SO_2 controls, EPA did not follow its own guidance document when conducting its four factor analysis of Independence. EPA failed to consider lower cost options that could reduce SO_2 emissions at Independence and instead concluded that BART-level controls were required to meet RPG. EPA did not prepare cost estimates based on design parameters for FGD systems retrofit at Independence, as required by their RPG guidance document. EPA did not conduct a dollar-per-deciview analysis, as recommended in its RPG document for these analyses to demonstrate the benefit of retrofitting dry FGD at Independence accounting for visibility benefits. When applying annualized costs to projected visibility improvements the result is over $1.3 billion/Δdv for Caney Creek and over $1.5 billion/Δdv for Upper Buffalo, which is clearly not cost effective.

[2] *See* S&L Report #012831 ("White Bluff Dry FGD Cost Estimate and Technical Basis") (July 2015).

1. INTRODUCTION

On April 8, 2015, the U.S. Environmental Protection Agency (EPA) published in the *Federal Register* a proposed rule that would partially approve and partially disapprove specific portions of the Arkansas State Implementation Plan (AR SIP) and issue a Federal Implementation Plan (FIP) that would regulate a group of Arkansas electric generating units (EGUs).[3] In this rule, EPA proposes to require additional SO_2 emission reductions that would require retrofitting new FGD systems on Entergy's White Bluff Station Units 1 and 2 and Entergy's Independence Station Units 1 and 2.

Sargent & Lundy (S&L) was contracted by Entergy to review EPA's proposed cost modifications as described in its Technical Support Document entitled, "Technical Support Document for EPA's Proposed Action on the Arkansas Regional Haze Federal Implementation Plan," hereinafter referred to as "FIP TSD," including one if its appendices, entitled "Appendix A. Technical Support Document for the SDA Control Cost Analysis for the Entergy White Bluff and Independence Facilities Arkansas Regional Haze Federal Implementation Plant (SO_2 Cost TSD)," hereinafter referred to as "Cost TSD."

S&L's experience in the electric power industry, as well as our experience with the Entergy facilities makes us uniquely qualified to perform this review. S&L has considerable experience with the federal and state environmental regulations affecting power plant operations, as well as the specification, evaluation, selection, and implementation of emission control technologies for both gas- and coal-fueled utility power facilities, including extensive experience with various FGD technologies. For example, since 2000, S&L has provided, or is currently providing, engineering services for the implementation of over 40 wet FGD projects, 30 dry FGD projects, and 25 dry sorbent injection (DSI) projects, all of which are technologies that are used to control SO_2 emissions. Our first-hand experience with these technologies provides us with a thorough understanding of both capital and operating and maintenance (O&M) costs associated with these technologies, as well as providing us with a comprehensive understanding of the achievable emission rates and limitations of these technologies.

S&L's analysis reveals that EPA overstates the cost-effectiveness (\$/ton of SO_2 removed) to retrofit dry FGD systems at White Bluff Units 1 and 2, which EPA proposes to require in its FIP. Cost-effectiveness is influenced by two variables: the total annualized cost of retrofit dry FGD systems (\$/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable. In its approach, EPA understated the annualized cost of the control systems and overstated the tons of SO_2 that would be removed by its FIP-imposed FGD retrofits.

[3] *See* 80 Fed. Reg. 18,944 (April 8, 2015).

2. Comments to the FIP TSD – SO_2 Emission Reduction Errors

The majority of S&L's comments are relative to EPA's Cost TSD; however, we note that in its FIP TSD, EPA incorrectly estimates both baseline emissions and SO_2 emission reductions that would result from the retrofit of dry FGD systems at White Bluff station. In addition, in proposing emission rates for White Bluff station, EPA proposed SO_2 emission limits that are consistent with performance guarantees offered by dry FGD suppliers during initial performance testing, not emission rates that are achievable over the 30-year life EPA assumed in its analysis. The following sections describe EPA's flawed analysis contained in the FIP TSD.

2.1 Baseline Emission Rates

Although baseline emission rates identified in Entergy's original BART analysis[4] were calculated based on the average annual emission rates from 2001 to 2003, in the FIP TSD, EPA redefines baseline emission by using a 3-year average of annual average SO_2 emissions from the years 2009 to 2013, excluding the years with the maximum and minimum annual averages.[5]

We can find no reason to reject EPA's selection of 2009 to 2013 as the baseline period as it represents more recent operation. However, the approach used by EPA to exclude the maximum and minimum values is entirely arbitrary and EPA does not explain how this approach represents a more realistic depiction of anticipated emissions from the existing sources.

The BART Guidelines state that baseline emissions from existing sources "should represent a realistic depiction of anticipated annual emissions for the source."[6] In general, for the existing sources, facilities should estimate the anticipated annual emissions based upon actual emissions from a baseline period.[7] However, EPA provides no explanation or analysis to demonstrate that the approach taken results in a realistic depiction of anticipated annual emissions from White Bluff and Independence. In addition, there is no basis for concluding that EPA's approach of excluding actual emissions data more accurately represents the actual operation of the units. Finally, to our knowledge, with the exception of EPA's proposed Texas FIP, this approach has not been used previously by EPA as a methodology for evaluating baseline emissions in other evaluations (and even if EPA had done so, it is not justified here).

The following table shows a comparison between the baseline emissions as established using EPA's approach and baseline emissions calculated as a straight average for various timeframes within the 2009-2013 period.

[4] Revised Bart Five Factor Analysis, White Bluff Steam Electric Station, Redfield, Arkansas, October 2013, Trinity Consultants.
[5] *See* EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, under Annual Emissions.
[6] 40 CFR Part 51 Appendix Y.
[7] *Id*.

Table 1: Comparison of Baseline SO_2 Emissions for White Bluff and Independence

Unit	EPA Approach 3 Year Average* (tons)	3 Year Average 2009-2011 (tons)	3 Year Average 2010-2012 (tons)	3 Year Average 2011-2013 (tons)	5 Year Average 2009-2013 (tons)
White Bluff 1	15,816	15,745	15,395	15,826	15,939
White Bluff 2	16,697	15,582	15,217	16,697	16,034
Independence 1	14,269	14,160	15,486	14,707	14,258
Independence 2	15,511	14,673	15,196	16,035	15,407

*EPA's approach includes 2009-2013 3-year average, excluding maximum and minimum years.

With the exception of White Bluff 1, EPA's approach of eliminating the maximum and minimum values results in higher baseline SO_2 emissions compared to averaging the entire 5-year period. In all cases, there is at least one other approach that would result in lower baseline SO_2 emissions compared to EPA's approach. By overestimating the baseline SO_2 emissions, EPA overstates the amount of SO_2 that would be removed and, thus, overstates the cost-effectiveness of the FGD retrofit projects.

2.2 SO_2 Emission Reduction

SO_2 emission reductions were estimated incorrectly by EPA for White Bluff and Independence. For each unit, EPA identified the maximum monthly SO_2 emission rate in the baseline period of 2009 to 2013 and then calculated the percent reduction that would be required to achieve a controlled emission rate of 0.06 lb/MMBtu. The percent reduction calculated was then multiplied by the baseline emission tons to determine the tons of SO_2 reduced. This methodology is incorrect because it assumes the baseline emissions calculated in the previous section are based on maximum monthly averages, which are significantly higher than the annual averages actually used to calculate baseline emissions.

The correct way to project the SO_2 emission reduction is to multiply the outlet emission rate of 0.06 lb/MMBtu by the average heat input to the boiler (MMBtu/year) from the baseline period. For example, the average heat input to White Bluff 1 over the baseline period of 2009 to 2013 was 55,829,551 MMBtu/year. Multiplying by 0.06 lb/MMBtu and then converting from pounds to tons results in estimated SO_2 emission reductions of 14,264 tons per year, as compared to EPA's 14,363. This method has been utilized by S&L on previous BART analyses, and has been accepted previously by EPA.

Table 2: SO_2 Emission Reductions for White Bluff and Independence

Unit	**EPA Approach** Using Maximum Monthly **SO_2 emission and 3-Year Baseline (tons)**	Using **5-Year Average** Heat Input and Baseline **(tons)**
White Bluff 1	14,363	14,264
White Bluff 2	15,221	14,353
Independence 1	12,912	12,607
Independence 2	13,990	13,655

Table 2 compares EPA's incorrect methodology to estimate SO_2 emission reductions at the Entergy Units to the more accurate methodology described above of using the 5-year average heat input from the baseline period. EPA's methodology overestimated the SO_2 emission reduction in all cases and therefore overstates the cost-effectiveness of the FGD retrofits at each unit.

2.3 SO_2 Emission Rate

EPA proposed SO_2 emission rates based on the assumption that a retrofit dry FGD will achieve a controlled SO_2 emission rate of 0.06 lb/MMBtu. In our experience, this assumption is unrealistic and cannot be sustained on a continuous, long-term basis. In several places, EPA cites the IPM dry FGD cost development document, which states: the "[r]ecommended SO_2 emission floor = 0.08 lb/MMBtu."[8]

EPA's proposal is too stringent to be achievable with the retrofit of an existing unit. A controlled SO_2 limit of 0.06 lb/MMBtu is not a realistic or sustainable value to maintain on a long-term basis when considering the normal variation in operation that occurs at all coal-fueled facilities. As noted in the IPM dry FGD document, the 0.06 lb/MMBtu emission rate corresponds to the lowest available SO_2 emission guarantees from dry FGD suppliers. Compliance with a vendor's guarantee value is typically demonstrated during very short term testing conducted at ideal operating conditions. Vendor guarantees do not reflect controlled emission rates that may be achievable on a consistent long-term basis as the unit operation varies from design conditions.

Dry FGD control systems, like all large air pollution control systems, are not steady state control systems, and controlled SO_2 emissions will continually fluctuate in response to changing operating parameters. Operating parameters that may affect SO_2 emissions include the fuel sulfur content, boiler load, load changes, flue gas flow rate, and flue gas temperatures, all of which continually change during normal operation of the boiler.

[8] Sargent & Lundy LLC, *IPM Model – Updates to Cost and Performance for APC Technologies, SDA FGD Cost Development Methodology*, March 2013.

Furthermore, as shown in Table 3, S&L investigated permit limits for dry FGD projects for Spray Dryer Absorber (SDA) projects similar to the dry FGD technology proposed for the White Bluff units, and Circulating Dry Scrubber (CDS) technology, which are more efficient dry scrubber systems because of increased flue gas and reagent contact through the use of a fluidized bed. As indicated, the lowest permit value for all units retrofitting dry FGD systems with averaging periods of 30 days was 0.09 lb/MMBtu, and that includes the more efficient CDS dry FGD systems. The last unit shown in the table includes the lowest permit limit of any of the dry FGD systems listed, but this value still contains the necessary margin because the averaging period is much longer (i.e. 12 months), and because the dry FGD system was installed as part of a new boiler project, so it was incorporated into the new unit design which inherently minimizes some of the design challenges associated with retrofitting, where non-ideal layouts can lead to non-ideal flow distribution inside the absorbers.

Projecting future emissions using the anticipated control system vendor guarantee (i.e., 0.06 lb/MMBtu) as EPA did is overly aggressive and provides no margin for normal operating conditions or long-term operation. A reasonable margin between the vendor guarantee value or design target, and the projected actual long-term achievable emission rate is needed to allow for normal fluctuations in the controlled emissions. In S&L's opinion, an operating margin of at least 0.02 lb/MMBtu between the vendor guarantee and projected long-term emission rate is reasonable. As indicated in Table, using a limit of 0.08 lb/MMBtu to provide the recommended margin would still be an aggressive permit limit compared to other dry FGD projects.

Table 3: SO_2 Permit Limits for Dry FGD Projects

Reference Plant	Permit SO_2 Limit	Permit Averaging Period
Plant 1 (SDA)	0.09 lb/MMBtu	30 day rolling
Plant 2 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 3 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 4 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 5 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 6 (SDA)	0.10 lb/MMBtu	30 day rolling
Plant 7 (CDS)	0.09 lb/MMBtu	30 day rolling
Plant 8 (CDS)	0.10 lb/MMBtu	30 day rolling
Plant 9 (CDS)*	0.07 lb/MMBtu	12-month rolling average

*This unit was a new unit, not a retrofit

EPA's approach to estimating controlled SO_2 emission rates is incorrect and based on a misunderstanding of the actual performance and operation of dry FGD technology. By using this approach, EPA is overestimating the tons of SO_2 removed and thus overstating the cost-effectiveness of the retrofit FGD control systems.

3. Comments to the Cost TSD – Annualized Cost Errors

S&L's remaining comments are focused on EPA's Cost TSD. Our comments follow the same organization of EPA's Cost TSD document and are contained in the following sections.

3.1 Cost TSD, Section 2 – SDA Cost Analysis Methodology

EPA states that the "Control Cost Manual uses the overnight method of cost estimating, widely used in the utility industry.[9]" To support this conclusion, EPA references its own characterization of the CCM methodology published in the preamble to the Oklahoma Regional Haze FIP.[10] Using the overnight methodology, EPA removed certain costs from the SDA cost estimate, including Owner's costs and interest incurred during the construction period. We disagree that the CCM describes an overnight approach to calculating capital costs. The CCM does not once define or even mention the overnight methodology as being the basis for estimating costs. Rather, the CCM describes a constant dollar approach that annualizes all capital costs and O&M costs (on a constant-dollar basis) over the useful life of the project.

In the Oklahoma rule EPA cited to an Energy Information Administration (EIA) document as support for using the overnight cost estimating concept. In fact, EPA stated that "EIA presents all of its projected plant costs in terms of overnight costs."[11] However, this is a mischaracterization of the methodology the EIA uses to develop capital costs for new power generation. The EIA document upon which EPA relied includes a clarifying footnote that states: "Starting from overnight cost estimates, EIA's electricity modeling explicitly takes account of the time required to bring each generating technology online and the costs of financing construction in the period before a plant becomes operational."[12] Therefore, EIA cost evaluations take into account financing costs, including AFUDC, one of the line items EPA insisted that Entergy remove[13] from the SDA capital cost estimate

Finally, EPA states that the overnight method is appropriate for BART determinations "because it allows different pollution controls equipment to be compared in a meaningful manner."[14] However, excluding financing costs will bias the cost-effectiveness comparison toward the high-capital options with extended construction periods. Project financing costs such as AFUDC may be minimal on projects that do not require significant capital and with short construction periods, but can be very significant on projects with large capital costs and extended construction periods. Excluding financing costs from the capital cost estimate results in the high-capital cost option appearing more cost-effective. Including financing costs allows the analyst to compare projects with varying capital requirements and varying construction periods.

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9 Cost TSD, page 1.
10 *Id.*
11 *Id.*
12 EIA, *Updated Capital Cost Estimates for Electricity Generation Plants*, November 2010, pg. 2.
13 *See* August 21, 2013 email from Dayana Medina of EPA Region 6 to Mary Pettyjohn of the Arkansas DEQ.
14 *Cost TSD, page 1.*

3.2 Cost TSD Section 2.3 – Use of the 2009 Alstom Cost Analysis

EPA invited Entergy to clarify certain issues associated with Alstom's 2010 quotation, including a misunderstanding regarding the scope of the dry FGD vendor's contract. In S&L Report #012831 of our comments, we have included a report that explicitly describes the scope of supply for the dry FGD vendor as compared to the balance of plant (BOP) scope of work. EPA made several incorrect assumptions regarding Alstom's scope that led to incorrect adjustments to the BOP cost estimate, as described in Section 3.3 of our comments. Furthermore, EPA's approach to escalating the Alstom quotation was incorrect as described in Section 3.5 of our comments.

3.3 Cost TSD Section 2.4 – Use of the S&L Balance of Plant Costs

EPA mistakenly subtracted BOP costs because they mistakenly believed the equipment to be included in Alstom's scope. As described in S&L Report #012831, the reagent handling system, which feeds the dry FGD supplier's reagent preparation system were not included in Alstom's scope. The "Dry FGD Island" supplied by the dry FGD vendor includes lime day bins, slakers, slurry transfer tanks, slurry transfer pumps, slurry storage tanks, and slurry feed pumps. The BOP system includes the cost associated with the "Reagent Handling System," which includes a rail delivery and unloading system for the lime, new rail spur, renovation of existing rail spur, delivery shed building, long-term storage silos, and a pneumatic conveying system to transfer the lime reagent from the long-term storage silos to the day bins, which are within the dry FGD vendor's scope.

We agree with EPA's comment that including the NO_X control equipment for Units 1 and 2 was an oversight and should not be incorporated into the Dry FGD estimates.

EPA mistakenly subtracted a total of $1,754,000 from the BOP quote because they mistakenly believed that all of the ductwork to be in Alstom's scope. The Dry FGD supplier's scope only includes ductwork between the dry FGD, the baghouse, and the booster fans. The ductwork to supply the flue gas to the SDA and the ductwork from booster fans to the existing chimney are within the BOP scope.

EPA mistakenly deleted a total of $255,000 to paint the Chimney because it did not understand this line item. Due to lower temperatures and higher moisture of the flue gas, downwash from the gas is more likely to occur and can lead to acid attack of concrete on the chimney shell; therefore, the costs to apply an acid resistant coating to the top 50 feet of the existing chimney shell was included in the estimate.

EPA mistakenly removed a total of $390,000 for costs associating with replacing and recalibrating the Continuous Emission Monitoring Systems (CEMS). The CEMS equipment reflected in Entergy's BART analysis was required because the existing CEMS was not capable of measuring SO_2 concentrations in the controlled range with Dry FGD technology. The costs included in the original estimate to cover replacement of the existing equipment with new equipment rated for the lower SO_2 concentrations as well as the cost to calibrate and certify these monitors including conducting a Relative Accuracy Test Audit (RATA) test.

Based on these comments, we have corrected EPA's cost subtractions in Table 4.

Table 4: Excluded BOP Costs (Corrected, Total for Both Units)

	Equipment	Material	Labor	Total
Total BOP Cost	$45,561,000	$35,120,000	$80,863,000	$161,544,000
Eliminate U1 NO_X Equipment	$3,622,000	$1,600,000	$3,073,000	$8,295,000
Eliminate U2 NO_X Equipment	$3,622,000	$1,600,000	$3,073,000	$8,295,000
Total Eliminated Cost	$7,244,000	$3,200,000	$6,146,000	$16,590,000
% BOP Items Reduced	15.90	9.11	7.60	N/A

EPA then adjusted additional cost items in the BOP estimate that were either percentages of the equipment, material, and labor costs or were related to equipment, material, and labor costs. EPA adjusted these items by applying the % reduction in cost of equipment, material and labor. Since EPA mistakenly removed cost items that should be included in the estimate, they over-estimated and misapplied percent reduction to the other items. In Table 4, we correct EPA's adjustments to remaining Entergy BOP costs by employing EPA's methodology but reducing the percentage factors to the values indicated in Table 5.

EPA excluded a total of $51,733,667 from the estimate, but Tables 4 and 5 show that only $20,724,543 was justified because NO_X control equipment had been included. Because of EPA's misconception as to the scope of work included in the BOP and Alstom estimates, they mistakenly concluded that costs were double-counted and removed $31,009,123 (total for both units) in costs that should be included. This resulted in EPA overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff.

Table 5: Adjustment to Remaining Entergy BOP Costs (Total for Both Units)

	EPA Cost TSD Reductions				Corrected Reductions*			
DESCRIPTION	Equipment	Material	Labor	Total	Equipment	Material	Labor	Total
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$546,061	$546,061	$0	$0	$656,036	$656,036
MOBILIZE/DEMOBILIZE @ 1% OF LABOR	$0	$0	$0	$0	$0	$0	$0	$0
COST DUE TO OVERTIME - 5-10'S	$0	$0	$7,970,183	$7,970,183	$0	$0	$9,575,359	$9,575,359
COST DUE TO OVERTIME - 5-10'S	$0	$0	$0	$0	$0	$0	$0	$0
PER DIEM - @ $10 PER HOUR	$0	$0	$7,888,659	$7,888,659	$0	$0	$9,477,416	$9,477,416
PER DIEM - @ $10 PER HOUR	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$0	$0	$0	$0	$0	$0	$0	$0
SPARE PARTS @ 1% OF EQUIPMENT	$327,060	$0	$0	$327,060	$400,318	$0	$0	$400,318
FREIGHT @ 5% OF MATERIAL	$0	$0	$0	$0	$0	$0	$0	$0
FREIGHT @ 5% OF MATERIAL	$0	$1,413,404	$0	$1,413,404	$0	$1,596,000	$0	$1,596,000
GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
GENERAL & ADMINISTRATIVE (G&A) @ 5% OFMATERIAL AND LABOR	$0	$1,413,404	$2,417,281	$3,830,686	$0	$1,596,000	$2,904,116	$4,500,116
GENERAL & ADMINISTRATIVE (G&A) @ 5% OF MATERIAL AND LABOR	$0	$0	$1,119,810	$1,119,810	$0	$0	$1,345,337	$1,345,337
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$0	$0	$0	$0	$0	$0
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$2,826,809	$4,833,794	$7,660,602	$0	$3,192,000	$5,807,308	$8,999,308
PROFIT @ 10% OF MATERIAL AND LABOR	$0	$0	$2,240,388	$2,240,388	$0	$0	$2,691,597	$2,691,597
NON CONTRACTOR INDIRECTS	$0	$0	$0	$0	$0	$0	$0	$0
ENGINEERING - BOP	$0	$0	$7,579,481	$7,579,481	$0	$0	$9,105,970	$9,105,970
Totals				$40,576,333				$48,347,457
Reduction in Remaining BOP Costs				$11,905,667				$4,134,543
Excluded BOP Costs from Table 4								$16,590,000
TOTAL BOP Reduction								**$20,724,543**

*Same methodology used as EPA but percentages applied are from Table 4

3.4 Cost TSD Section 2.5 – Undocumented or Disallowed Cost Items

Owner's Costs include a variety of costs incurred by the owner to support the air pollution control project. Owner's Costs are project-specific, but generally include costs incurred by the Owner to manage the project, hire and retain staff to support the project, and costs associated with third party assistance associated with project development and financing. Owner's Costs typically include, but may not necessarily be limited to:

- Site investigations (geotechnical, hydrology, etc.) for project design
- Environmental permitting/approvals
- Insurance during construction
- Site security during construction
- Transmission interconnection (if applicable)
- Fuel interconnection (if applicable)
- Owner's mobilization costs
- Owner's project management and support staff
- Insurance advisor
- Labor relations consultant
- Tax consultant
- Financial advisor
- Legal advisor
- Market consultant
- Community relations/community outreach program.

Owner's Costs are real costs that the owner will incur during the project and are typically included in cost estimates prepared for large air pollution control retrofit projects. In fact, U.S. EPA's Coal Quality Environmental Cost (CUECost) model includes Owner's Costs (or "Home Office" costs) in its air pollution control system cost estimating workbook and interrelated set of spreadsheets.[15] CUECost uses a factor of 10% of the total installed cost to estimate Owner's Costs and Engineering Costs for limestone forced oxidation and lime spray dryer control systems.

To address the items in this section, we included a section in S&L Report #012831 that describes Entergy's Owner's costs and how they were developed. We believe EPA deleted these Owner's costs because EPA did not understand how they were defined and therefore, incorrectly assumed that they did not reflect real costs to Entergy. In total, EPA removed $41,741,743 per unit from the original estimate which should be included. Removing these costs resulted in EPA overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff and Independence. Detailed explanations of these costs are included in S&L Report #012831 to help EPA understand

[15] *See*, Coal Utility Environmental Cost (CUECost) Workbook Development Documentation Version 5.0, prepared by U.S. EPA, September 2009, pages 17 and 34.
Appendix B, pages B-3 and B-6.

these costs.

3.5 Cost TSD Section 2.6 – Escalation

We agree with EPA's assertion that the application of escalation is allowed by the CCM.[16] However, EPA's method of using Chemical Engineering Plant Cost Indices (CEPCI) to escalate costs to the year 2013 resulted in severely underestimating the costs associated with escalation. CEPCI are sometimes used to estimate escalation by multiplying base costs by the ratio of the index for the year costs are to be escalated to the index for the year in which the costs were originally generated. For example, EPA used CEPCI from 2009 (521.9) and 2013 (550.8) to escalate the FGD costs from a 2009 basis to a 2013 basis. Thus, EPA applied the following formula, 550.8/521.9*$247,856,184 to obtain an estimated 2013 FGD cost of $261,581,119 for both units.

Rather than estimating escalation of Alstom's pricing from 2010, S&L (on behalf of Entergy) requested updated FGD pricing from Alstom in 2013[17]. We agree with a reference cited in the CCM and authored by EPA which states, "At best [cost indices] provide a cloudy mirror…there is no substitute for current price information obtained from suppliers of those goods and services."[18] Nothing illustrates EPA's conclusion that cost indices are not to be substituted for supplier information better than comparing EPA's escalation rate to the actual escalation rate indicated in Alstom's budgetary quotations as shown in Table 6.

Table 6: Alstom Quotation Comparison (Total for Both Units)

Parameter	EPA	Vendor Quotation
FGD Cost 2009	$247,856,184	$247,856,184
FGD Cost 2013	$261,581,119	$297,904,000
Average Escalation	1.36%	4.7% per year

As shown in Table 6, EPA underestimated escalation significantly, resulting in underestimating the 2013 dry FGD costs by $36,322,881 (total for both units). In fact, EPA applied CEPCI indices in several instances from 2008 that *de-escalated* costs, resulting in lower costs in 2013 as compared to 2008. We note specifically that EPA's cost calculations ignored the updated 2012 direct annual costs provided by Entergy, and instead included the 2008 costs.[19] Table 7 summarizes how EPA incorrectly estimated escalation in its analysis for White Bluff Unit 1 and corrects that by applying an average escalation rate of 4.7% to match the Alstom quotation. We note that information from Alstom showed their pricing escalated nearly equivalently for

16 *See* Cost TSD, Section 2.6, page 8

17 Updated FGD pricing from Alstom is used as the basis of the 2015 cost estimate documented in S&L Report #012831.

18 Escalation Indexes for Air Pollution Control Costs, United States Environmental Protection Agency, October 1995, pp. 3-4.

19 *See*, EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, tab "Entergy Costs"

equipment/material (~4.8%) and for installation (~4.6%). Since the difference was negligible we applied the average 4.7% in the revised costs shown in Table 7. EPA's underestimation of cost escalation carried through their analysis and resulted in an incorrect reduction in the cost estimate of over $42 million per unit.

Table 7: Summary of EPA's Escalation Errors (Per Unit)[20]

Item	Entergy	EPA (2013)	Corrected Costs Including Escalation (2013)	Escalation Costs Omitted by EPA
Total Contractor Costs* (2010)	$156,974,274	$161,676,662	$180,164,213	$18,487,550
Contingency (2010)	$20,875,711	$21,501,073	$23,959,697	$2,458,624
Balance of Plant (2008)**	$102,085,500	$75,145,724	$115,401,842	$13,316,342
Balance of Plant Indirect Costs (2012) ***	$9,768,175	$0	$10,227,279	$1,494,175
Misc Contract Labor (2012)	$4,583,719	$0	$4,799,154	$215,435
Entergy Internal Costs (2012)	$20,076,644	$0	$21,020,246	$943,602
Capital suspense (2012)	$8,348,276	$0	$8,740,645	$392,369
Total Capital Investment (TCI)		$258,323,459	$319,525,752	
Direct Annual Costs (2008)	$7,901,369	$7,790,140	$9,941,130	$2,150,990
Indirect Annual Costs				
Overhead (2008)	$2,572,707	$2,536,491	$3,236,859	$700,368
Administrative Charges @ 2% of TCI		$5,166,469	$6,390,515	$1,224,046
Property Tax @ 1% of TCI		$2,583,235	$3,195,258	$612,023
Insurance @ 1% of TCI		$2,583,235	$3,195,258	$612,023
Total Indirect Annual Costs		$12,869,429	$16,017,889	
Total Escalation Costs Underestimated by EPA				**$42,607,547**

* This item reflects the updated dry FGD pricing received in 2013
** As EPA did, this item subtracts the excluded BOP costs discussed in Section 3.3 before applying the escalation
*** In the Cost TSD, EPA incorrectly used the 2008 BOP Indirect Costs from the Revised Bart Five Factor Analysis, SDA Cost analysis rather than the 2012 BOP Indirect Costs as identified. The differential between the 2008 and 2012 BOP Indirect Costs ($1,035,071) was included in the column for Escalation Costs Omitted by EPA.

[20] *See* Cost TSD, Table 5 on page 10

3.6 Cost TSD Section 2.7 – Operating and Maintenance (O&M) Costs

Although EPA claims in its proposal that it relied on the methods and principals contained within the Control Cost Manual in developing its individual control technology cost estimates, in the supporting Cost TSD EPA stated that "we can compare Entergy's O&M costs to those obtained through the use of our IPM SDA cost model."[21]

The IPM model and the Control Cost Manual provide two entirely different approaches to calculating control system capital and O&M costs. IPM is described by EPA as a multi-regional, dynamic, deterministic linear programming model used by EPA to analyze system-wide impacts of air emissions policies on the U.S. electric power sector in the 48 contiguous states and the District of Columbia.[22] The model has been used by EPA to analyze impacts associated with proposed regulatory programs such as the Clean Air Interstate Rule (CAIR) and Mercury and Air Toxics Standard (MATS). The primary purpose of the model is to provide forecasts of least-cost capacity expansion, electricity dispatch and emission control strategies for meeting energy demand and environmental, transmission, dispatch and reliability constraints. The model includes cost modules for various air quality control technologies, and S&L developed the cost algorithms used in the IPM model to estimate costs associated with DSI, SDA, and wet FGD control systems.[23] The IPM model is not referred to in either the Control Cost Manual or the BART Guidelines as an acceptable tool to develop site specific capital or O&M cost estimates.

Cost algorithms in the IPM model were developed based on a statistical evaluation of cost data available from various industry publications, and do not take into consideration site-specific cost issues.[24] The primary purpose of the IPM cost modules is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. By necessity, the cost algorithms were designed to require minimal site-specific information available from publicly available sources. Because of the limited number of site-specific inputs, the IPM cost algorithms provide order-of-magnitude control system cost estimates, but they do not provide case-by-case project-specific cost estimates meeting the requirements of the BART Guidelines, nor do the IPM equations incorporate the cost estimating methodology described in the Control Cost Manual.

Regarding O&M costs for SDA FGD systems, the IPM model includes the following assumptions that are not consistent with a site-specific O&M cost estimates:

- A fixed quantity of additional personnel to operate the equipment is included, not accounting for site-specific project and staffing needs;

[21] *See* Cost TSD, Section 2.7, page 9.
[22] *See*, EPA website: www.epa.gov/airmarkt/progsregs/epa-ipm/.
[23] *See*, e.g., IPM Model- Updates to Cost and Performance for APC Technologies Wet FGD Cost Development Methodology, Sargent & Lundy LLC, March 2013.
[24] *Id.*, at page 1.

- While we agree with the general practice of estimating maintenance material and labor costs as percentage of capital costs, the IPM model does not estimate site-specific capital costs sufficiently upon which to apply this percentage, and the assumed percentage cannot be modified to accommodate project specific requirements;
- The assumptions incorporated in the maintenance material and labor costs are propagated into the administrative labor item, and is therefore limited by the same items as the previous item;
- Reagent consumption assumes a stoichiometry that cannot be modified to match vendor-supplied guarantees for a specific application;
- Reagent consumption also depends upon a flue gas temperature into the SDA of 300°F and cannot be modified to apply site-specific temperatures;
- Reagent consumption also depends upon lime purity, which the IPM model assumes to be 90% and cannot be modified to match actual reagent supply information;
- The IPM model estimates water consumption based on gas flow and fuel sulfur levels instead of performing site-specific calculations using actual fuel properties and operating conditions;
- Waste generation is a function of the assumed lime stoichiometry discussed above as well as an assumed moisture content of 10% that cannot be modified to match vendor-supplied mass balances for specific applications; and
- The SDA flue gas pressure drop estimate included in the IPM model is an average value based on flue gas flow rate and sulfur levels instead of performing site-specific calculations that consider the actual fuel properties, operating conditions, and actual equipment sizing and arrangement.

EPA's use of IPM to benchmark O&M costs is thus not an appropriate choice for a unit-specific analysis consistent with BART guidelines. By relying on the IPM cost modules to verify dry FGD O&M costs, EPA did not adequately evaluate and account for potential project-specific site constraints that Entergy would incur to operate the FGD control systems EPA is proposing. In addition, using the IPM cost algorithms to calculate FGD control system capital or O&M costs is inconsistent with the case-by-case BART cost analysis described in the BART Guidelines for at least two reasons. First, the IPM model does not account for unit-specific design and operating parameters that can affect control system design and costs, including operating costs. Second, the IPM cost equations do not take into consideration site-specific conditions that could affect the O&M costs to operate the control system.

Please see additional comments in the next section of our comments (3.7), addressing EPA's adjustment of the O&M cost estimates to account for lower coal sulfur.

3.7 Cost TSD Section 3.1 – Entergy's Coal Sulfur Assumption

EPA states that an uncontrolled SO_2 emission rate of 2.0 lb/MMBtu at White Bluff is "far in excess of sulfur level of the coals it has historically burned," and concludes, "[t]hus Entergy has costed SO_2 scrubber systems for the White Bluff facility that are overdesigned compared to its historical needs." Based on this conclusion, EPA adjusts the capital and O&M costs using a design sulfur level selected by EPA. While we agree with EPA that direct O&M costs be revised to 0.68 lb/MMBtu, this sulfur level is completely inadequate for the Dry FGD equipment design basis.

EPA correctly assumes that the 2.0 lb/MMBtu design basis was to preserve fuel flexibility, but their conclusions that, "either (1) this higher cost be balanced against its greater SO_2 reduction potential, or (2) that the scrubber system's capability and cost be adjusted down to match the facility's historical emissions," are without basis and inconsistent with BART guidelines.

The SO_2 emission reduction calculation depends upon the baseline emissions, baseline heat input, and the required outlet emission rate (see Section 2.2 of our comments). SO_2 emission reduction does not depend on the fuel sulfur levels selected for FGD system design, neither the BART guidelines nor the CCM address evaluating potential future SO_2 reduction based on design fuels as part of the BART analysis or cost estimating methodology. Therefore, EPA's first conclusion that the higher costs be balanced against greater SO_2 reduction potential is inconsistent with BART requirements and has no basis.

Although the BART guidelines and the CCM both account for the development of a design basis, there are no specific requirements that air pollution control design be tied to historical operating trends. Therefore, EPA's second conclusion that capital costs must be adjusted to match historical emissions is arbitrary and without basis.

Based on its erroneous conclusions, EPA selected a maximum monthly fuel sulfur level of 0.68 lb/MMBtu as the design basis used to estimate the capital costs. Figure 1 illustrates why the use of White Bluff's maximum monthly fuel sulfur level is completely insufficient. The ability to reduce SO_2 emissions depends critically upon the amount of reagent, or lime that can be added to the FGD system. With a 0.68 lb/MMBtu design basis, the reagent preparation and delivery equipment would be inadequately sized to add lime when sulfur levels increase beyond that level. As shown in Figure 1, EPA's design basis would result in emissions above the proposed emission rate for almost half of the operating time. This design approach would require limiting fuel sulfur levels to below 0.68 lb/MMBtu to ensure continuous compliance. If this is the approach EPA is intending, then the cost analysis would need to be revised to incorporate significant additional costs associated with fuel purchasing limitations. We did not include any additional O&M costs associated with fuel limitations because we believe EPA selected the design basis due to a lack of experience rather than intending to place enforceable limits on fuel purchasing at White Bluff station.

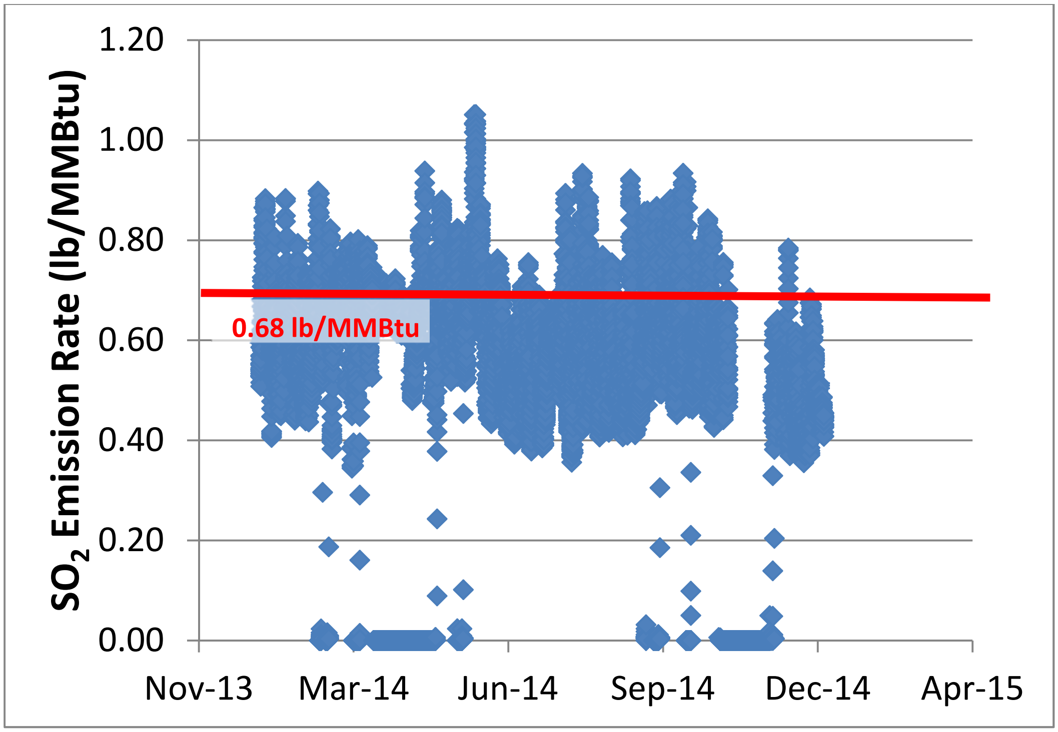

Figure 1: 2014 SO_2 Emissions for White Bluff 1[25]

While we believe that the 2008 design basis of 2.0 lb/MMBtu was appropriate at that time based on the potential to fire fuels with higher sulfur levels, based on more recent information, Entergy now believes that they will not purchase fuels with sulfur levels higher than 1.2 lb/MMBtu. The operating data shown in Figure 1 confirms that 1.2 lb/MMBtu would result in a design basis that would ensure continued compliance with EPA's proposed FIP emission rates. Therefore, we have provided a revised cost estimate based on 1.2 lb/MMBtu. To illustrate the small difference in capital costs associated with the revised design basis (1.2 lb/MMBtu versus 0.68 lb/MMBtu), S&L has included a sensitivity analysis in S&L Report #012831.

As discussed previously, we agree that it is appropriate to base direct O&M cost estimates on 0.68 lb/MMBtu fuel sulfur levels to represent average operational costs. However, EPA's adjustment factor of 0.5823 applied to direct O&M costs severely underestimated these costs. In agreement with EPA's sulfur basis, S&L developed O&M costs for the 0.68 lb/MMBtu operating case in S&L Report #012831 based on site specific consumption rate estimates and unit costs. Our report estimated O&M costs including direct variable and fixed O&M costs to be a total of $10,166,000 per unit in the first year. By comparison, EPA's calculation scales direct O&M costs of $7,790,140 by 0.5823, resulting in direct O&M costs of $4,536,199 per unit being

[25] Downloaded from EPA's Clean Air Market Database.

included in its cost-effectiveness calculation.[26] This methodology underestimated direct O&M costs by $5,629,801 per unit.

In addition, EPA applied the same O&M factor of 0.5823 to the indirect annual costs, including overhead, administrative charges, property tax and insurance, all of which depend on capital cost.[27] Therefore, assuming EPA's capital cost scaling methodology for capital cost is correct (which we do not believe is the case), then EPA should have applied the 0.9584 factor used to correct capital costs to the indirect annual costs. EPA's methodology underestimated indirect O&M costs by $4,840,192 per unit.

3.8 Cost TSD Section 4.1 – EPA's Conservatism in Cost Estimating

EPA lists two assumptions it believes are conservative in its Cost TSD. In one assumption, EPA noted that amortization from the 2008 S&L cost analysis was 40 years, but they lowered the remaining useful life to 30 years, which increases the cost-effectiveness. EPA's estimate is not conservative with regard to equipment life because, as EPA states, they, "typically assume a 30 year equipment life for scrubbers,"[28]and the 2008 amortization value from S&L was not intended to be used to conduct the BART analysis. Furthermore, as discussed in Section 3.9, the actual remaining life of these units is far below what EPA assumed.

In the second assumption, EPA concludes that two absorber vessels are not required and, thus, a 7% cost savings that could have been realized was not applied. We do not believe EPA is qualified to design dry FGD systems, and therefore not qualified to evaluate the number of vessels that are suitable for White Bluff. Dry FGD systems of this type have not been applied to units of this size, and the dry FGD supplier quoted three absorber vessels for this application based on their expertise. EPA cites no reference where fewer absorber vessels have been installed for a unit with an identical design basis, and therefore its assertion that two absorber vessels is adequate is arbitrary and without basis.

3.9 Remaining Useful Life

EPA states, "With regard to consideration of the remaining useful life of the units, we are not aware of any enforceable shutdown date for the Entergy White Bluff Plant, nor did Entergy's evaluation indicate any future planned shutdown."[29] Therefore, EPA utilized 30-years as the remaining useful life in its cost-effectiveness calculations. As stated in Entergy's comments to the proposed rule, Entergy proposes to cease coal-firing at the White Bluff units between 2027 and 2028. The proposed rule requires that the FGD controls and White Bluff be operational 5 years after the effective date of the rule. Assuming the effective date of the final rule is one year after the comment period closes, then the White Bluff FGD's will need to be operating by July of

[26] *See*, EPA-R06-OAR-2015-0189-0093-White Bluff_R6 cost revisions2.xlsx, tab "Cost-Effectiveness" Cell D4.
[27] *Id.*
[28] Cost TSD, Section 4.1 page 16.
[29] AR FIP TSD, p. 80.

2021. Based on the coal-cessation dates of White Bluff Units 1 and 2, the remaining useful life of these FGD systems is therefore between 6 and 7 years, instead of 30 years used in EPA's analysis.

4. Cost TSD Section 5 – Inclusion of Independence under Reasonable Progress Goals (RPGs)

EPA included Entergy's Independence Plant in its RPG analysis based on annual emissions from the facility.[30] It is beyond the scope of S&L's comments to address the basis upon which EPA decided to include Independence in its RPG analysis for Caney Creek and Upper Buffalo. Instead, our comments focus on the inconsistencies and errors included in EPA's RPG analysis for the Independence station.

In EPA's RPG analysis for SO_2 Controls, EPA concluded that the units at White Bluff and Independence Stations are similar enough to apply "the total annualized dry FGD and wet FGD costs [they] developed for the White Bluff units to the Independence units."[31] EPA then calculates the cost-effectiveness to retrofit FGD systems at Independence by adjusting the White Bluff cost effectiveness calculations to account for the differences in SO_2 emissions at Independence. This approach is flawed for several reasons. First, this approach includes all of the errors in EPA's cost-effectiveness analysis for White Bluff as described in the preceding sections, including errors in calculating baseline emissions, errors in calculating emission reductions, and errors associated with estimating annualized costs. Second, applying the White Bluff annualized costs to Independence is inconsistent with EPA's RPG guidance which requires cost estimates based on design parameters be developed for air pollution control systems.

To determine whether air pollution controls would be required at Independence Units 1 & 2 to meet the Reasonable Progress Goals at Caney Creek and Upper Buffalo, EPA conducted an RPG four factor analysis. The four factor analysis is described in EPA's RPG Guidance Document, and includes an evaluation of: (a) costs of compliance; (b) time necessary for compliance; (c) energy and non-air impacts; and (d) the remaining useful life of the source.[32] Regarding the first factor listed, costs of compliance, EPA suggests that, for stationary sources, the following steps be performed:

a) Identify the emissions units to be controlled;

b) Identify the design parameters for emission controls; and

c) Develop cost estimates based upon those design parameters[33]

EPA did not perform steps b and c of the RPG compliance cost evaluation. Rather, EPA relied upon an EIA database comparison as well as an aerial photo comparison of the two units to justify applying the White Bluff FGD costs to Independence. The EIA information does not contain any information that would be used to set the design basis for either FGD system;

[30] *See* 80 Fed. Reg. 18,991 (April 8, 2015).
[31] *Id.*, at page 18,992.
[32] *See* "Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program," U.S. EPA June 1, 2007, pg 1-3.
[33] *Id.*, at page 5-1.

therefore it cannot be used to conclude the FGD system design at Independence would be identical to White Bluff. Furthermore, EPA's use of aerial photos to indicate visual similarities between White Bluff and Independence ignores many site-specific factors that cannot be captured in a Google Earth image downloaded from the internet. Some of the site-specific factors that EPA did not account for by using this approach and which could result in different costs to retrofit FGD technology at Independence as compared to White Bluff include:

- EPA proposes the same timeline for compliance for White Bluff and Independence which will add significant labor costs due to the amount of skilled labor that would be required to construct four FGD systems in the same time period;
- EPA did not review plant operating data, such as flue gas temperatures, which affect flue gas volume, potentially requiring different equipment sizing for Independence;
- EPA did not review operating and maintenance practices at Independence, which could result in different O&M costs;
- EPA did not assess differences in underground utility interferences that could potentially change the equipment arrangement at Independence;
- EPA did not conduct subsurface geotechnical investigations to determine differences in soil conditions or distances to reach bedrock that would impact foundation design or seismic design requirements;
- EPA did not assess other seismic design requirements such as seismic risk or magnitude of potential earthquakes to determine steel design differences that may be required; and
- EPA did not assess differences in wind loads which could impact foundation and structural steel design.

In its guidance document, EPA states, "[f]or additional guidance on applying the cost of compliance factor to stationary sources, you may wish to consult the BART guidelines."[34] We note that, for EPA's RPG analysis for Independence, EPA did not revisit any of the steps required as part of a BART analysis; therefore, EPA ignored other lower cost technologies or methodologies to reduce SO_2 emissions at Independence station. EPA's inherent assumption is that BART-level SO_2 reductions are required at Independence to meet the RPGs, but it does not adequately support that assumption. EPA modeled visibility impacts of SO_2 reductions assuming FGD systems would be retrofitted at Independence, but they failed to conduct modeling using any other technology or methodology that could provide more cost-effective SO_2 reductions.

Finally, EPA also states in its RPG guidance document that for, "individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation."[35] EPA's CENRAP modeling showed that the cumulative benefit of installing all of the controls proposed in the FIP would result in visibility benefits at Caney Creek of only 0.21 dv and at Upper Buffalo of only 0.19 dv.[36] Considering that

[34] *Id.*, at page 5-1.
[35] *Id.*, at page 5-2.
[36] *See* 80 Fed. Reg. 18,998, Table 67.

Independence represents only approximately 36% of the SO_2 point source emissions and 29% of the point source NO_X emissions in Arkansas, Entergy estimated the visibility improvement due to retrofitting FGD systems at Independence would be approximately 0.08 dv at Caney Creek and 0.07 dv at Upper Buffalo. Although we do not support EPA's use of the White Bluff cost estimates for Independence, we applied the White Bluff costs to retrofit dry FGD and the estimated visibility improvement due to retrofitting dry FGD systems at Independence to estimate dollar-per-deciview as suggested in EPA's RPG guidance document. Table 8 shows that retrofitting dry FGD systems at Independence is clearly not cost effective when considering the insignificant visibility improvements.

Table 8: Dollar-Per-Deciview Reduction for Dry FGD at Independence

Class I Area	Caney Creek	Upper Buffalo
Estimated Visibility Improvement[37]	0.08	0.07
Revised Annualized Costs[38]	$106,765,022	$106,765,022
$/Δdv	$1,334,562,775	$1,525,214,600

[37] The CENRAP modeling includes SO_2 and NO_X impacts; therefore, the numbers shown likely overestimate the visibility improvement based solely on SO_2 reductions.
[38] Annualized costs for Retrofitting Dry FGD at White Bluff 1 and 2 from S&L Report #012831 were used assuming a 30-year remaining useful life.

5. CONCLUSION

S&L reviewed the approach EPA takes in its proposed FIP for Arkansas, including EPA's determination of costs for retrofit dry FGD scrubbers, and EPA's evaluation of annual SO_2 emission reductions. Our analysis identifies several areas where EPA overstates the cost-effectiveness ($/ton of SO_2 removed) of the dry FGD retrofits that EPA would require in its FIP. As discussed in this analysis, cost-effectiveness is influenced by two variables: the total annualized cost to retrofit FGD controls ($/yr) and the corresponding reduction in annual SO_2 emissions (tons per year "tpy"). EPA's approach does not accurately calculate either variable. Table 9 shows how the approach EPA took understated the annualized cost of the control systems and the adjustments S&L made to correct EPA's errors.

Table 9: Adjustments to EPA's Annualized Cost for a Single Unit at White Bluff

Item	Total Capital Investment ($)	Annualized Cost ($/year)
EPA FIP	$247,537,295	$31,981,230
Corrected BOP Cost Exclusions	$263,041,857	$33,230,898
Corrected Owner's Cost Exclusions	$304,783,600	$36,595,282
Corrected Escalation	$347,391,147	$40,029,450
Corrected Operating Costs	$347,391,147	$50,499,444
Remaining Useful Lifetime Adjustment*	$347,391,147	$86,975,068 to $95,381,830
2015 Estimate (S&L Report #012831)*	**$536,185,000**	**$109,681,936 to $122,657,613**
Differential from EPA FIP*	**+ $99,853,852**	**+ $54,993,838 to $63,400,600**

* Entergy proposes to cease to use coal at White Bluff 1 and 2 between 2027 and 2028; therefore, the annualized costs are shown as a range based on a remaining useful life of 6 or 7 years.

In addition, Table 10 shows how EPA's approach overstated the tons of SO_2 that would be removed by its FIP-imposed dry FGD and the adjustments S&L made to correct EPA's mistakes.

Table 10: Adjustments to EPA's SO_2 Emission Reductions

Item	White Bluff 1 (tons)	White Bluff 2 (tons)
EPA FIP	14,363	15,221
Corrected Baseline Emission Calculation	14,474	14,617
Corrected SO_2 Emission Reduction Calculation	14,264	14,353
Differential from EPA FIP	**-99**	**-868**

EPA's errors resulted in severely overstating the cost-effectiveness to retrofit dry FGD systems at White Bluff 1 and 2 (and then by extension in its reasonable progress analysis for Independence 1 and 2). Table 11 summarizes how EPA's errors systematically underestimated cost and overstated the cost-effectiveness to install these dry FGD systems. As Table 11 indicates when the errors are corrected and updated costs incorporated, retrofitting dry FGD systems at these units is clearly not cost-effective.

Table 11: Summary Cost-Effectiveness Impacts

Item	White Bluff 1 ($/ton)	White Bluff 2 ($/ton)
EPA's Cost Effectiveness	$2,227	$2,101
Corrected Baseline Emission Calculation	$2,210	$2,188
Corrected SO_2 Emission Reduction Calculation	$2,242	$2,228
Corrected BOP Cost Exclusions	$2,330	$2,315
Corrected Owner's Cost Exclusions	$2,566	$2,550
Corrected Escalation	$2,806	$2,789
Corrected Operating Cost	$3,540	$3,518
Corrected Remaining Useful Life *	$6,097 to $6,687	$6,060 to $6,646
2015 Estimate (S&L Report #012831) *	**$7,689 to $8,599**	**$7,642 to $8,546**
Differential from EPA FIP[1]	**+ $5,462 to $6,372**	**+ $5,541 to $6,445**

* Entergy proposes to cease to use coal at White Bluff Units 1 and 2 between 2027 and 2028; therefore, the cost effectiveness values are shown as a range based on a remaining useful life of 6 or 7 years.

With respect to EPA's RPG analysis for SO_2 controls, EPA did not follow its own guidance document when conducting its four factor analysis of Independence. EPA failed to consider lower cost options that could reduce SO_2 emissions at Independence and instead concluded that BART-level controls were required to meet RPG. EPA did not prepare cost estimates based on design parameters for FGD systems retrofit at Independence, as required by their RPG guidance document. EPA did not conduct a dollar-per-deciview analysis, as recommended in its RPG document for these analyses, to demonstrate the benefit of retrofitting dry FGD at Independence accounting for visibility benefits. When applying annualized costs to projected visibility improvements the result is **over $1.3 billion/Δdv** for Caney Creek and **over $1.5 billion/Δdv** for Upper Buffalo, which is clearly not cost effective.

White Bluff 1	EPA FIP	Corrected Baseline Emissions	Corrected Heat Input and Emission Reduction	Section 2.4, Excluded BOP Costs	Section 2.5, Excluded Owner's Costs	Section 2.6, Incorrect Escalation	Section 2.7, Corrected Operating Cost	Remaining Useful Lifetime Adjustment (7 Year Life)	Remaining Useful Lifetime Adjustment (6 Year Life)	2015 Capital Cost Estimate (S&L Report # 012831 - 7 Year Life)	2015 Capital Cost Estimate (S&L Report # 012831 - 6 Year Life)
Total Annualized Cost	$31,981,230	$31,981,230	$31,981,230	$33,230,898	$36,595,282	$40,029,450	$50,499,444	$86,975,068	$95,381,830	$109,681,936	$122,657,613
Interest Rate (%)	7	7	7	7	7	7	7	7	7	7	7
Equipment Lifetime (years)	30	30	30	30	30	30	30	7	6	7	6
Capital Recovery Factor (CRF)	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.1856	0.2098	0.1856	0.2098
SO2 Emission Rate (lbs/MMBtu)[2]	0.65	0.65	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Baseline Heat Input (MMBtu/yr)[1]	Not Used	Not Used	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551	55,829,551
Controlled SO2 Emission Rate (%)	90.81	90.81	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Controlled SO2 Emission Rate (lb/MMBtu)[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
SO2 Emission Baseline (tons)	15,816	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939	15,939
SO2 Emission Reduction (tons)	14,363	14,474	14,264	14,264	14,264	14,264	14,264	14,264	14,264	14,264	14,264
Cost Effectiveness ($/ton)	$2,227	$2,210	$2,242	$2,330	$2,566	$2,806	$3,540	$6,097	$6,687	$7,689	$8,599
White Bluff 2											
Total Annualized Cost	$31,981,230	$31,981,230	$31,981,230	$33,230,898	$36,595,282	$40,029,450	$50,499,444	$86,975,068	$95,381,830	$109,681,936	$122,657,613
Interest Rate (%)	7	7	7	7	7	7	7	7	7	7	7
Equipment Lifetime (years)	30	30	30	30	30	30	30	7	6	7	6
Capital Recovery Factor (CRF)	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.0806	0.1856	0.2098	0.1856	0.2098
SO2 Emission Rate (lbs/MMBtu)	0.68	0.68	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Baseline Heat Input (MMBtu/yr)[1]	49,108,824	47,158,824	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262	56,042,262
Controlled SO2 Emission Rate (%)	91.16	91.16	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used	Not Used
Controlled SO2 Emission Rate (lb/MMBtu)[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
SO2 Emission Baseline (tons)	16,697	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034	16,034
SO2 Emission Reduction (tons)	15,221	14,617	14,353	14,353	14,353	14,353	14,353	14,353	14,353	14,353	14,353
Cost Effectiveness ($/ton)	$2,101	$2,188	$2,228	$2,315	$2,550	$2,789	$3,518	$6,060	$6,646	$7,642	$8,546

1 - EPA did not list the heat input. EPA's analysis incorrectly assumes the annual averageheat input as being the baseline SO_2 emissions (tpy) divided by the monthly maximum emission rate (lb/MMBtu)

2- EPA incorrectly applied the maximum maximum monthly SO_2 emission rate to determine the % reduction in SO_2 to achieve 0.06

3- EPA did not include this item. SO_2 emission reduction is corrected to calculate it as [baseline annual average heat input (MMBtu/Yr)] * [the controlled SO_2 emission rate (lb/MMBtu)]*[2000 lb/ton]

ENTERGY ARKANSAS, INC.

WHITE BLUFF DRY FGD

COST ESTIMATE AND TECHNICAL BASIS

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EXECUTIVE SUMMARY

The purpose of this study is to estimate the total capital investment and operating and maintenance (O&M) costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2 using an Engineer, Procure, Construct (EPC) contracting strategy. A preliminary conceptual design was developed for implementation of dry FGD technology at the White Bluff station to serve as the technical basis of the capital and O&M estimates.

The capital cost estimate includes the following components which comprise the total cost the Owner will incur to install dry FGD technology at White Bluff:

- FGD Island Cost supplied by a Dry FGD System Supplier including the main process equipment
- Balance of Plant Cost including auxiliary equipment and systems, foundations and buildings, site work, demolition and relocation
- Other Direct and Construction Indirect Costs including labor premiums, freight, contractor's G&A and profit
- Indirect Costs including engineering, startup spare parts, technical field advisors, and the additional fee associated with an EPC contracting strategy
- Escalation and Interest During Construction associated with the project duration for implementation of a large air quality control technology
- Owner's Costs including internal labor, insurance, and initial lime reagent fill
- Third Party Services including construction management oversight, start-up and commissioning oversight, Owner's Engineer services, and performance testing
- Project Contingency to cover unknown and undefined scope associated with the project which would result in additional cost to the Owner

The total capital investment to install dry FGD on White Bluff Units 1 and 2 was estimated to be $1,072,370,000. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%. In addition, the O&M costs were estimated to be approximately $10,166,000 per year per unit and include the cost of lime (reagent), byproduct disposal, auxiliary power, water, replacement bags and cages, maintenance costs, and operating labor.

1. PURPOSE

The purpose of this study is to estimate the total capital investment and operating and maintenance costs associated with installing dry flue gas desulfurization (FGD) technology on White Bluff Units 1&2. This report documents the conceptual design and technical basis for the dry FGD cost estimate.

2. APPROACH

2.1 TECHNOLOGY SELECTION

Sargent & Lundy (S&L) previously performed an evaluation of wet and dry FGD technology for Entergy's White Bluff Station. The evaluation included development of a preliminary conceptual design for both wet and dry FGD systems at the White Bluff station. The preliminary designs were used as the basis of an evaluation which compared the overall economics of each system, including capital and operating costs. The study concluded that a dry FGD system had an economic advantage over wet FGD when the design coal sulfur is below 3 lb SO_2/MMBtu. Based on the current market and potential future regulations, dry FGD technology would have an economic advantage over wet FGD for SO_2 reduction at the White Bluff station.

2.2 CONTRACTING APPROACH

Many utilities elect to utilize a one contract engineer-procure-construct (EPC) approach for major retrofit projects, such as large FGD projects. The EPC approach allows the Owner to contract with one entity which then manages the overall project. The EPC Contractor procures the material, equipment and services needed to complete the project and the EPC Contractor takes full responsibility for the equipment and work supplied by each of its subcontractors.

With this approach the Owner takes on less risk in the overall management and coordination of the project. However, shifting this risk to the EPC Contractor increases the total price for the EPC contract; "Whilst there are… numerous advantages to using an EPC contract, there are some disadvantages. These include the fact that it can result in a higher contract price than alternative contractual structures. This higher price is a result of a number of factors not least of which is the allocation of almost all the construction risk to the contractor."[1] The additional cost due to an EPC contracting approach is represented in our cost estimate as an EPC Risk Fee.

The Owner's control over design details of the system is limited, using this contracting strategy, to the requirements specified in the contract. This results in an additional upfront effort for the Owner and the Owner's Engineer to thoroughly define the project in the specification. Whatever is not defined will be excluded from the EPC Contractor's scope resulting in potential change orders. The Owner and Owner's Engineer are also responsible for reviewing the EPC Contractor's submitted design drawings and schedules to ensure what has been agreed upon in the final contract is included.

2.3 CAPITAL COST DEVELOPMENT

The capital cost estimate is based on project-specific information, including:

- A preliminary conceptual design developed for implementation of dry FGD technology at the White Bluff station.
- An engineer-procure-construct (EPC) contracting strategy.
- A Dry FGD System Supplier, subcontracted by the EPC Contractor, providing the main process equipment as a complete FGD Island.
- The FGD Island equipment and installation cost is based on a budgetary proposal received from Alstom in September 2013. The budgetary proposal is based on installing SDA technology on both of the White Bluff units.

The capital cost estimate includes the following components which comprise the total price of the EPC Contract to complete the work:

- Equipment and material
- Installation labor
- Demolition and Relocation work
- Indirect field costs and BOP engineering
- Freight on Materials
- General and Administration
- Erection contractor profit

[1] "EPC Contracts in the Power Sector", prepared by DLA Piper, 2011, page 6. See: https://www.dlapiper.com/

- Engineering, Procurement and Project Services
- Spare parts
- EPC Fee
- Escalation

The equipment design basis is summarized in Section 3 of this report and the scope of the estimate is summarized in Section 4. The project definition and accuracy of the individual components included in this estimate result in an overall accuracy of ±20-25%.

In order to estimate the *total plant* capital cost for installation of FGD at White Bluff, the following costs which would be incurred outside of the scope of the EPC contract were included:

- Owner's Costs
- Third Party Services – Construction Management Oversight
- Third Party Services – Startup and Commissioning Oversight
- Third Party Services – Owner's Engineer
- Third Party Services – Performance Testing
- Project Contingency
- Interest During Construction or Allowance for Funds Used During Construction

The cash flow provided in Attachment 2 is based on a monthly progress payment schedule developed using the preliminary execution schedule included in Attachment 3. Specific details regarding the milestones making up the payment schedule are listed in Attachment 4. Below is a summary of those activities that represent major or large payment milestones.

Month	Date	Milestone
1	February 2017	Award EPC Contract Execution
5	June 2017	EPC Contractor Procures Major Equipment
7	August 2017	EPC Contractor Procures Major Equipment
10	November 2017	Flue Gas Ductwork Procurement Initiated by EPC Contractor
13	February 2018	SDA and Fabric Filter Design Drawings
15	April 2018	Award Fabric Filter Bags and Cages Flue Gas Ductwork Start of Fabrication
17	June 2018	Physical Flow Model Completed

Month	Date	Milestone
19	August 2018	Mobilize On-Site
20-38	September 2018 to March 2020	Construction Activities
41	June 2020	Unit 1 Substantial Completion
45	October 2020	Unit 2 Substantial Completion
		Demobilization Complete
46	November 2020	Unit 1 Final Acceptance
47	December 2020	Unit 2 Final Acceptance

Each monthly cash outlay in the cash flow is broken down by category (labor, equipment and materials, and indirect costs).

3. DRY FGD CONCEPTUAL DESIGN AND SYSTEM COMPONENTS

A conceptual design for the implementation of Dry FGD at the White Bluff station was developed by Sargent & Lundy LLC (S&L) as a precursor to the development of the cost estimate. A general arrangement drawing showing the conceptual design is included in Attachment 7. The dry FGD conceptual design was developed for each of the following subsystems:

3.1 DRY FGD ISLAND

3.1.1 Reagent Preparation System

Lime will be supplied to the lime day bins from the long-term storage silo located in the Reagent Handling Area and supplied by the EPC Contractor. The lime day bins, located in the Reagent Preparation Area and provided by the Dry FGD System Supplier, will each have a storage capacity to supply the plant with lime reagent for 24 hours when firing 1.2 lb SO_2/mmBtu coal.

Lime from the day bin will be gravity-fed through feeders to a lime slaker, where the lime will be slaked (mixed with low pressure service water and converted from calcium oxide to calcium hydroxide slurry). The plant will have a total of two lime slaking trains (2 x 100%), each sized to process enough lime slurry to supply the entire plant. Each lime slaker will discharge to a lime slurry transfer tank, which is equipped with two lime slurry transfer pumps which will feed into the lime slurry storage tanks. The common lime slurry storage tanks will each be sized for 12 hours of storage for the entire plant when burning a 1.2 lb SO_2/mmBtu coal. The lime day bin, slaking trains, and lime slurry tanks are sized to provide the necessary reagent slurry to both units simultaneously. The lime slurry tanks are built with cross-ties such that either slurry tank can feed either the Unit 1 or Unit 2 FGD systems.

A total of four lime slurry feed pumps (two per unit), each sized for 100% flow to one unit, will pump the lime slurry from the storage tanks to the SDAs through one of 2 x 100% piping loops, and return unused slurry back to the lime slurry storage tank. The closed-loop reagent supply line requires a flow velocity between 4-10 fps to avoid any solids buildup in the piping. Because of this, the pumping requirement is higher than the actual SDA requirement and must be sufficiently greater than the slurry flow that is pumped into the absorbers to allow the returning flow to remain above 4 fps.

3.1.2 Absorbers

Three absorbers, each treating 33⅓% of the flue gas are provided for each unit. Depending on the supplier and the type of atomizer normally used, there may be one rotary atomizer per absorber with a shared spare (B&W), three rotary atomizers per absorber with one or more shared spares (Alstom, basis of the estimate), or multiple dual-fluid atomizers with 15% shared spares (Siemens). The cost estimate includes contingency to capture the possibility of any of these designs.

3.1.3 Baghouse

Each SDA will be paired with a pulse-jet baghouse with a gross air-to-cloth ratio of approximately 3.2-3.4 ft/min. The filter bags in each baghouse are cleaned by pulses of compressed air. The air compressors will be 4 x 33% for the station and are included in the scope of the baghouse supplier.

3.1.4 Byproduct Recycle System

The reaction byproducts from the absorbers will be collected in the baghouses and a portion of the collected material will be recycled. The baghouse hoppers will be emptied through air lock feeders and pneumatically conveyed to two recycle day bins located in the Byproduct Recycle Area and supplied by the Dry FGD System Supplier, which are common for both units. The air-lock feeders are installed without a spare. One recycle day bin is located in the recycle train for each unit. The common byproduct recycle day bins (one per unit) provide 8-hours of storage when burning 1.2 lb SO_2/mmBtu coal.

Each byproduct recycle day bin is equipped with two recycle slurry preparation systems. The byproduct in each recycle day bin is gravimetrically conveyed to one of two systems where the byproduct is slurried with water (cooling tower blowdown). The byproduct recycle slurry is stored in one of four plant wide recycle slurry tanks, two per unit (combined 4-hour storage capacity).

Two recycle water make-up tanks are located in the recycle area with a capacity of 250,000 gallons (to be supplied by the EPC Contractor). The recycled by-product slurry will be combined with fresh lime slurry for feed to the SDA atomizers. Recycle feed slurry pumps (4 x 100%, two installed per unit) will be used to transfer the recycle slurry from the recycle slurry tanks to the atomizers. In addition, all recycle feed lines are provided in a loop configuration as with the reagent system, with a complete redundant loop to allow unhindered operation due to any pluggage of pumps or feed piping.

3.2 REAGENT HANDLING SYSTEM

As part of the conceptual design, several lime delivery methods were evaluated and it was determined that rail delivery provided the best alternative for White Bluff based on ease of implementation, overall plant interface, and lowest evaluated cost (in terms of required capital investment and delivered cost of lime). Therefore, the basis of the estimate is delivery of lime via hopper-bottom railcars with truck unloading as a backup. In order to accommodate rail delivery to the site, a new rail spur will be constructed from the existing track bordering the west side of the plant. Lime trains will enter and exit the station from this spur. A trackmobile car positioner will position railcars, two at a time, in the enclosed delivery shed for unloading. The cost estimate includes the capital cost associated with railcar unloading, including the new rail spur and the renovation of the existing rail spur to handle lime delivery. A vacuum pneumatic system will unload the railcars into either of the two (2) lime storage silos. The lime storage silos will be sized for supply of reagent for 14 days of storage at full load when firing 1.2 lb SO2/mmBtu coal. Lime from the long-term storage silos will be pneumatically transferred to two lime day bins located in the Reagent Preparation Area and supplied by the Dry FGD System Supplier.

3.3 BYPRODUCT HANDLING SYSTEM

Excess FGD byproduct from the recycle system will be pneumatically conveyed to either of the two common long- term FGD byproduct storage silos. The two long-term FGD byproduct storage silos are each sized to handle the byproduct for a total of 7 days of storage when firing the 1.2 lb SO_2/mmBtu coal. The byproduct will be mixed with a small amount of fly ash and water to form a final product which contains approximately 65% FGD byproduct, 5% fly ash, and 30% water. In order to achieve this mixture, a common fly ash blending bin (7-day storage) will be located near the new byproduct silos. The feed rate of fly ash discharged from the blending bin is controlled to maintain the ratio of byproduct to fly ash. A pneumatic airslide conveyor will discharge fly ash directly into an unloading conditioner, simultaneously mixing fly ash with the proper ratios of water and FGD byproduct (discharged from the silo). The wetted byproduct/fly ash mixture is then loading into dump trucks, which will deposit the FGD byproduct in a final storage location in the landfill. A bulldozer will maintain the landfill pile. The capital cost for the silos, conveying system and byproduct/fly ash blending system is included in the cost estimate. As part of the conceptual design, the existing landfill was evaluated and was determined to have sufficient capacity to accommodate the addition of FGD byproduct. Therefore no costs were included in the capital estimate for the (existing) landfill. In addition, it was assumed that the existing haul trucks would be used to transport the FGD byproduct.

3.4 FLUE GAS HANDLING SYSTEM

The flue gas from the existing ID fans will be ducted to the absorbers. The gases from the absorbers will be ducted to the baghouses to collect the reaction by-products and residual fly ash. Two axial booster fans (2 x 50% for each unit) will be located downstream of the absorbers and baghouse; the booster ID fans can be provided by the Dry FGD System Supplier or the EPC Contractor. Due to the dry condition of the scrubbed flue gas, the existing stack and liners will be used for the retrofit case.

The existing chimney and carbon steel liners were evaluated as part of the conceptual design and were deemed to be suitable for a dry FGD application. In addition, the top 50 feet of the existing chimney liners are constructed of 316 stainless steel so an acid resistant coating on the liner is not required. However, downwash may result in acid attack and discoloration on the outer concrete shell of the chimney; it was determined that an acid resistant coating to the top 100 feet of the concrete shell is recommended; therefore, the cost estimate includes the coating of the top 100 feet of the chimney’s outer concrete shell.

3.5 ELECTRICAL BOP SYSTEM

The existing auxiliary power system was evaluated as part of the conceptual design for the White Bluff dry FGD system. In order to feed the new dry FGD and other BOP equipment, significant modifications and additions to the existing power system are required. These include installation of new auxiliary transformers, medium- and low-voltage switchgear buses, motor control centers (MCCs) and upgrades to the isolated phase tap-off buses.

3.6 I&C BOP SYSTEM

As part of the conceptual design, the existing control system was evaluated to determine the required modifications necessary to implement dry FGD technology at the White Bluff station. The dry FGD system will be controlled using a new Foxboro I/A system which will integrate with the existing power block Foxboro I/A system. The control processors, I/O cabinets, and other system components will be located in the new electrical equipment building (EEB) for each unit. Two HMIs will be installed in the new EEB for each unit to provide any local controls for the lime preparation and byproduct recycle systems provided by the Dry FGD System Supplier. The baghouse will be controlled through the Allen-Bradley ControlLogix PLC and the ID booster fans will be controlled through the existing Foxboro I/A system controller(s), which are used to control boiler air and furnace pressure.

4. CAPITAL AND O&M COST ESTIMATE TECHNICAL BASIS

The following summarizes the design inputs used as the basis for the White Bluff dry FGD Systems:

- Design SO_2 inlet concentration of 1.2 lb SO_2/MMBtu for equipment design.
- SO_2 inlet concentration of 0.68 lb SO_2/MMBtu for annual operating costs.
- Design SO_2 outlet concentration of 0.06 lb SO_2/MMBtu.
- Annual capacity factor of 72.46% (based on Entergy's future operating profile).
- Compliance deadline of December 2020.

4.1 EPC CONTRACT PRICE

The Dry FGD System Supplier will provide all of the equipment within the FGD Island. The FGD Island will include the Reagent Preparation Equipment, Absorber Area Equipment, Baghouse Area Equipment and the Byproduct Recycle Equipment. The booster ID fans could be provided by either the Dry FGD System Supplier or the EPC Contractor; the basis of this estimate is supply of the booster fans by the Dry FGD System Supplier. The EPC Contractor will provide the remaining BOP scope in order to provide a complete and operable FGD system. In addition, the EPC Contractor will install/construct the entire system including the equipment provided by the DFGD supplier.

The scope of work for the cost estimate is broken out by area below:

1. <u>Dry FGD Island</u>
   a. Reagent Preparation System, common to both units:
      - Two lime day bins, 24-hours storage each
      - Two detention lime slakers at 100% capacity, each with a grit screen, gravimetric feeder
      - Two lime slurry transfer tanks
      - Four slurry transfer centrifugal pumps
      - Two lime slurry storage tanks
      - Four slurry feed centrifugal pumps
      - Cost estimate based on budgetary proposal from Alstom; the budgetary proposal is based on a design sulfur of 2.0 lb/MMBtu, cost adjustments were included in the estimate for a lower design sulfur of 1.2 lb/MMBtu. These cost adjustments were developed by estimating the differential equipment cost for the reagent preparation and waste handling equipment. The impacted equipment is identified in Section 4.5 which discusses the sulfur design basis sensitivity.

b. Absorber Area, per unit
- Three absorber vessels per unit, with access doors
- Rotary atomizers, two spare atomizers included
- Vessel material carbon steel, ¼ in. – ⅝ in. carbon steel
- Heating and ventilation
- Vacuum piping
- SDA Superstructure
- Cost estimate based on budgetary proposal from Alstom

c. Baghouse Area, per unit
- New baghouse, including pulse jet cleaning system and all appurtenances
- Cost estimate based on budgetary proposal from Alstom

d. Byproduct Recycle System, per unit (located remotely in common location for both units)
- One recycle silo with bin vent filter per unit, 8-hour total capacity
- Two recycle mix tanks per unit
- Two recycle slurry tanks per unit, with two recycle slurry centrifugal pumps per unit
- Agitators for each tank
- Baghouse ash handling system common to both units
- Rotary air-lock valves from baghouse hopper outlets to pressure pneumatic conveying system (60-degree typical)
- Pneumatic pressure blowers (8 x 33⅓ %)
- Cost estimate based on budgetary proposal from Alstom

e. ID Booster Fans, per unit
- Two approximately 5,200 hp axial booster fans per unit sized to overcome pressure drop associated with FGD and baghouse
- Includes motors - no spare motor included
- Cost estimate based on budgetary proposal from Alstom
- Dampers from ID fan to booster fans (cost estimated separately, not included in Alstom budgetary proposal)

2. <u>FGD Island Foundations and Enclosures</u>

a. Absorber tower foundations including caissons

b. Baghouse area foundations including 18” auger cast piles 60’ long

c. Booster fan area foundations

d. 6" insulation with lagging for Absorbers and Baghouses (cost estimated separately, not included in Alstom budgetary proposal)

e. Penthouse enclosure for Absorbers located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)

f. Two elevators (one for each unit) to provide maintenance access to Absorber and Baghouse Areas

g. Enclosure around hoppers for Baghouses located in FGD Island (cost estimated separately, not included in Alstom budgetary proposal)

h. Lime preparation building for Reagent Preparation Area in FGD Island, 50' x 50' x 50', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

i. Byproduct recycle building for Byproduct Recycle Area in FGD Island, 60' x 60' x 60', including substructure and superstructure (cost estimated separately, not included in Alstom budgetary proposal)

3. <u>Reagent Storage and Handling, common to both units:</u>

a. Lime rail car unloader:

- Lime delivery via 25-car unit train
- System consists of mobile receiving pan and associated vacuum pneumatic equipment to unload railcar through railcar bottom hoppers
- Enclosed railcar unloading building
- One vacuum pneumatic system operating to unload a car
- Pneumatic vacuum exhausters (2 x 100%)
- Filter separator with vacuum-to-pressure transfer hopper and valves
- One lot of pneumatic conveying piping located on an above-grade sleeper pipe rack
- Cost estimate based on vendor quote from United Conveyor Corporation (UCC) for a similar unit

b. Lime storage silos:

- Two silos, 14-days storage and capable of storing a train load of lime, 2,400-tons storage total, including substructure and superstructure
- 32' diameter and 95' height to top
- 1,200-tons storage, each
- Continuous level detection systems
- Bin vent filters
- Live bottom hopper outlets
- Rotary airlock assemblies

- Lime transfer systems:
  - Pressure pneumatic conveying system from lime storage silos to lime day bins
  - Pneumatic pressure blowers (3 x 100%)
  - One lot of pneumatic conveying piping located on an elevated pipe rack

c. Concrete foundations including caissons for all material silos

d. Concrete foundations for pneumatic conveying blowers and exhausters

4. Byproduct Handling System, common to both units

a. Two FGD by-product storage silos (7-day capacity each, common to both units) with bin vent filter, fluidizing system, and two unloading conditioners (one operating, one spare per silo)

b. One common fly ash blending, 7-day storage bin with bin vent filter, fluidizing system, and four pneumatic airslide conveyors

c. Water pumps and associated piping for unloading conditioners (pin mixers) at both silos

d. Compressed air system for air operated valves

e. Storage silo substructure and superstructure

f. Continuous level detection system

g. One lot pneumatic conveying piping located on an above grade pipe rack

h. Two truck scales and substructure

i. Existing road improvements for truck haulage to existing landfill

j. Cost estimate based on budgetary proposal from UCC for similar project

k. Concrete foundations including caissons for all material silos

l. Concrete foundations for pneumatic conveying blowers and exhausters

5. Flue Gas Handling System, per unit

a. ID fan outlet to absorber inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6” insulation with lagging

b. Absorber outlet to baghouse inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6” insulation with lagging

c. Baghouse outlet to new booster fans and fan outlet to the stack inlet ductwork and supports:
   - Carbon steel, ¼ in.
   - Velocity, 3,600 fpm
   - 6” insulation with lagging

d. Concrete foundations for all flue gas ductwork

e. Epoxy trowel coating on top 100 feet of outside of chimney shell

6. Civil BOP

   a. Roadwork

   b. Site grading

   c. Soil removal earthwork

   d. Excavation, backfill, and compaction for all foundations

   e. Storm sewer work

   f. Two-cell pond for wastewater storage of process water/slurry

   g. Laydown Area
      - Development of a new laydown area, approximately 10 acres, including site preparation, fencing, and temporary power. It was assumed that this area would be located on existing plant property, and does not required land to be purchased.

   h. Highway Intersection Upgrade to provide sufficient plant access for construction period
      - New Bypass Lane on Westside of Highway 365
      - New Southbound Left Turn Lane on Highway 365
      - New Northbound Merge Lane on Highway 365
      - New Northbound Right Turn Lane on Highway 365
      - Extension and upgrade of existing Contractor Haul Road (Highway 46 Spur) to Highway 365
      - Widening of the existing Main Plant Road from the Contractor Haul Road (Highway 46 Spur) to Main Guard House
      - Track crossing signal system at Haul Road (Highway 46 Spur) track crossing

   i. New warehouse building 200’ x 75’ x 15’, including substructure and superstructure.

7. Mechanical BOP System

   a. Interconnecting piping, above-ground and buried

   b. Valves for interconnecting piping, above-ground and buried

   c. Lime slaking water storage tank, 115,000-gallon capacity

   d. Slaker water 3” in-line heaters, 475 kW each

e. Recycle make-up water tanks, 2 x 250,000-gallon capacity

f. Pipe Racks, common to both units
- Between lime railcar unloading enclosure and lime silos
- Between lime silos and lime day bins
- From baghouse hoppers to recycle silos and FGD by-product silo
- From lime slurry storage tanks to absorber
- From recycle slurry storage tank to absorber
- Concrete foundations including caissons for all pipe racks
- Shallow concrete foundations for other miscellaneous structures

g. BOP Pumps
- Three by-product recycle water forwarding pumps to recycle slurry, 1000 gpm @ 150' TDH
- Four reagent prep/recycle sump pumps, 120 gpm @ 150' TDH
- Two lime silo and unloading area sump pumps, 120 gpm @ 150' TDH
- Two by-product ash silo area sump pumps, 120 gpm @ 150' TDH
- Two by-product recycle make-up water tank supply pumps, 2600 gpm @ 200' TDH
- Two lime slaking water pumps, 750 gpm @ 100' TDH
- One new Low Pressure Service Water (LPSW) pump, 20,000 gpm @ 100' TDH, including new intake structure, piping and valves
- Two leachate pumps, 50 hp

h. Instrument Air System, common to both units
- Air compressors; 2 x 100%, 250 scfm each @ 100 psig
- IA dryers w/filters; 2 x 100%, 250 net scfm each
- Air receivers; 2 x 100%
- Instrument air piping to every silo or day bin, bin vent and reagent preparation/recycle area
- Heat-traced piping

i. Service Air System, common to both units
- Air compressors; 2 x 100%
- Air receivers; 2 x 100%

j. Field painting
- Multiple coat system used for exposed ductwork only
- Inorganic zinc primer and polyurethane system used for steel
- Allowance for underground piping shop coatings built into piping cost

8. Demolition and Relocation

   a. Hazardous material accumulation building

   b. Ash handling maintenance building

   c. Drainage ditch

   d. Pipe trench

   e. Fabrication shop

   f. Existing contractor electrical hook up

   g. Existing drainage ditches, rerouted with new concrete trenches

   h. Relocation of ACI injection location from the air heater inlet to upstream of the DFGD

   i. Rail Yard Extension, common to both units

      - Extend rail spur to north to allow lime train to be unloaded and cars to be stored on site, designed for 136 lb rail to be consistent with existing coal spurs

   j. Fire Protection System Modifications

      - Deluge system has been included for the new transformers
      - Allowances have been included for fire protection in all of the new buildings; including piping and post indicator valves
      - The new fire protection systems will tie-in to the existing system on-site. It was assumed that the current capacity of the plant fire protections system is sufficient to accommodate the new systems; an evaluation of the current system capacity was not performed.

9. Electrical BOP System

   a. One 115-kV, 1200A isolation disconnect switch

   b. One startup transformer

   c. Two unit auxiliary transformers (UAT)

   d. Three medium-voltage (6.9-kV) switchgear buses (outdoor walk-in type)

   e. Two medium-voltage (6.9-kV) double ended switchgear per unit (total of two)

   f. Two 480-V double ended switchgear buses per unit (total of four)

   g. Six 480-V motor control centers per unit (total of twelve)

   h. Four 6.9-kV/480-V step-down transformers per unit (total of eight)

   i. Two isolated phase UAT tap bus extensions

   j. Non-segregated phase bus

   k. Medium-voltage cable

   l. Low voltage, control and instrumentation cable, as necessary

   m. Two electrical equipment buildings

10. Instrumentation and Controls BOP System

    a. Controls System based on an estimated number of I/O points:

        - Approximately 1,000 I/O points are required for each unit's DFGD system (including reagent preparation), for a total of 2,000 I/O points the cost of which is included in Alstom budgetary proposal pricing.
        - Approximately 2,000 I/O points for the common areas at the station, located outside of the DFGD Island.

    b. CEMS, per unit

        - Existing CEMS analyzers for both units will be recalibrated and recertified; if the existing CEMS analyzers cannot be recalibrated for lower SO_2 emission, new CEMS analyzers will be installed.

11. Labor Costs

Installation/labor costs were included in the base estimate under the direct costs. Manhours are estimated for each item in the base estimate and are based on the type of work and typical estimates for similar work. The labor costs are based on the labor wage rates and labor crews developed by S&L.

    a. Labor Wage Rates

    Crew labor rates were developed using prevailing craft rates, fringe benefits and state specific worker's compensation rates as published in the 2015 edition of R.S. Means Labor Rates for Pine Bluff, Arkansas area. Costs were added to cover FICA, workers compensation, all applicable taxes, small tools, incidentals, construction equipment, and contractor's overhead. A 1.15 geographic labor productivity multiplier is included based on the Compass International Construction Yearbook for Arkansas. The crew rates do not include an allowance for weather related delays.

    b. Labor crews

    Construction/erection labor cost is based on the use of applicable construction crews typically required for projects of this type. The construction crew costs were specifically developed for utility industry and are proprietary to S&L. The prevailing craft rates are incorporated into work crews appropriate for the activities, and include costs for small tools, construction equipment, insurance, and site overheads.

12. Other Direct and Construction Indirect Costs

In addition to the base labor costs, other construction indirect costs for the project were broken out in the estimate as well as other contractor direct costs. The following items were included as other direct and construction indirect costs.

    a. Scaffolding and Consumables
    b. Premiums and per diems ($10 per hour)
    c. Overtime is included based on five 10-hour shifts per week work schedule

d. Freight on construction materials

e. Contractor's General & Administration Fees (included at 10% of total direct and construction indirect costs)

f. Contractor's Profit (included at 5% of total direct and construction indirect costs)

13. EPC Indirect Costs

The final contribution to the overall EPC project price are the EPC Contractor's indirect costs; these include the EPC engineering services, startup spare parts and initial fills, technical field advisors, and the EPC risk fee.

a. EPC Engineering Services

The EPC engineering services was estimated based on recent projects with similar scopes and schedules. The total cost of the EPC engineering services was estimated to be $23,000,000 without escalation.

b. Startup Spare Parts and Initial Fills

An allowance has been included for initial fills for equipment, including first fills for lubrication of any motorized equipment. The initial fill of pebble lime was not included in the EPC Contractor's scope, as this is considered to be an operating cost rather than a capital expense. The initial fill of pebble lime is included in the Owner's costs.

c. Technical Field Advisors (Vendors)

Allowances were included for equipment supplier's technical field advisory services based on an estimated 300 man-days. The estimate includes technical field advisors for the FGD system supplier (including FGD system subcontractors) and the DCS supplier.

d. EPC Risk Fee

An EPC approach provides an alternative which is expected to reduce risk for Entergy by placing the responsibility for the project on a single entity, the EPC Contractor. The EPC Risk Fee is a premium included by the contractor which accounts for the additional coordination and management of the project as well as the additional risk assumed by the contractor (See Section 2.2 for a discussion on the contracting strategy and the EPC Risk Fee). Based on S&L's experience with recent EPC projects, an EPC Risk Fee was included at 10% of the total EPC project costs.

14. Escalation

Escalation was included in the estimate based on the preliminary execution schedule at an escalation rate of 2.15% on equipment and materials and 3.35% on labor and indirects. These escalation rates were developed by S&L based on recent pricing and in-house escalation projections.

For commodities and equipment related to power plant construction, S&L tracks over 200 U.S. indices from major industrial sources such as BLS, Chemical Engineering, Handy Whitman, and Engineering News Records. S&L reviews the various indices in order to develop an overall average and then evaluates the change in the indices over the last three years and the last five years. Based on this analysis, an annual rate of 2.15%/year escalation is projected for commodities and equipment for the time frame for the project.

S&L uses RS Means as the basis for estimating labor craft rates. In order to project the escalation rate for the estimate, S&L reviewed five major craft labor types typically used in the power plant industry over the last five years using the average cost of craft labor. Based on this information, S&L projected an annual rate of 3.35%/year escalation on labor and indirects.

15. Sales Tax

    Sales Tax is included in the estimate, and was applied at a rate of 8.125% on all material costs.

4.2 OVERALL PROJECT COSTS FOR CAPITAL ESTIMATE

Outside of the EPC Contractor's total cost, Entergy will incur other costs associated with the project, such as Owner's costs, services procured from third parties (including Owner's engineer, construction management support, startup and commissioning support and performance testing), and other project related costs. The following summarizes the additional project costs to Entergy associated with installing dry FGD at the White Bluff Station:

1. Owner's Costs (by Entergy)

   Owner's Costs are direct costs that the Owner incurs over the life of the project. Entergy estimated the cost for the following items which would be real costs Entergy would incur based on the scope and schedule of this project:

   a. Internal Labor – For all major projects, Entergy assigns internal resources to manage the project from initiation through development, contracting, installation, and commissioning. Internal labor includes personnel from several departments including Capital Project Management & Technology, Engineering, Fossil Operations, Legal, Environmental Services, Supply Chain, Risk Management, Finance, Regulatory, and the Operating Company. The internal labor is estimated based on a proposed staffing plan, developed from the project scope and preliminary schedule using average wage rates. Costs are based on the following anticipated staffing levels:

      - Project Development (through EPC Award) – 25 months, equivalent of 10 people
      - Project Execution (beginning at EPC Award) – 53 months, equivalent of 22 people

   b. Internal Indirects – Indirect costs incurred by Entergy include a payroll allocation, materials and supplies allocation, a depreciation allocation, and capital suspense allocation. The payroll allocation includes payroll overhead costs for items such as employee benefits. The materials and supplies allocation is used to distribute the overhead costs of managing storerooms that are used to procure, track, and issue material and supplies. The depreciation allocation distributes depreciation and amortization expenses for the new assets. Capital suspense is a distribution of overhead costs associated with administrators, engineers, and supervisors and includes function specific rates and A&G (Corporate Accounting) rates.

c. Travel Expenses –Travel expenses are included to support the oversight of the project, including travel for site-visits, monthly status meetings, critical design reviews, etc. Travel expenses are estimated based on projects with similar schedules and scope.

d. Legal Services – Legal services are contracted from external law firms. These services include contract and regulatory compliance support. Entergy estimated the cost of the legal services based on recent EPC projects.

e. Builders Risk Insurance - Builder's Risk Insurance is included in the estimate and covers the materials, equipment, and labor associated with a large scale construction project in case of physical loss or damage. The estimated is based on estimated project value and schedules.

f. Initial Fills - Entergy will procure a supply contract for pebble lime to the station. Under this contract, Entergy will arrange to provide the initial fill of pebble lime to the station for startup, commissioning, and performance testing. A 120 day supply of pebble lime for both units has been included in the estimate based on the reagent pricing identified in Section 4.3.

2. Third Party Services – Construction Management Oversight

The construction management support was estimated based on the proposed staffing plan shown below, developed from the overall project scope and the preliminary schedule. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. The cost of labor is based on present day cost, without escalation. Travel and living expenses are based on the current per diem rate for the White Bluff area of $129/day. Costs are based on the following anticipated staffing levels:

a. Home Office Support – 15 months, 1 person

b. On-Site Construction Manager – 35 months, 1 person

c. On-Site Construction Admin/Project Controls Engineer – 35 months, 1 person

d. Construction Field Engineers – 31.5 months, 2 people

The total cost of the Construction Management Support was estimated to be $4,969,000 without escalation.

3. Third Party Services – Startup and Commissioning Oversight

The startup and commissioning support was estimated based on similar project scopes. It was assumed that Entergy will not have the internal support personnel required to perform this task, and therefore it will be outsourced. Costs are based on the following anticipated staffing levels:

a. Commissioning Support Specialists – 8 months, 2 people

The total cost of the startup and commissioning support was estimated to be $550,000 without escalation.

4. Third Party Services – Owner's Engineer

The Owner's Engineer cost includes scope as summarized below and was estimated based on the preliminary project schedule, including assumptions on manpower requirements, as well as a comparison cost to other projects with similar scope.

The cost of labor is based on present day cost, without escalation. Costs are based on the following scope for the Owner's Engineer work:

a. Conceptual Study Support
b. EPC Specification Supporting Documents
c. Project Schedule Development
d. EPC Specification Development
e. EPC Bid Evaluation and Contract Conformance
f. General Project Support
    - Monthly Project Status Meetings
    - Weekly Teleconferences
    - Overall Coordination
    - Project Administration
    - Site Visits and Travel
g. Permitting (Construction Permits and Modification to Title V and Solid Waste Permits)
h. Design Review of Drawing Submittals
i. Technical support during design, fabrication, construction, commissioning, and testing
j. Equipment vendor QA/QC audits

The total cost of the Owner's Engineer was estimated to be $6,750,000 without escalation.

5. Third Party Services – Performance testing

The cost for performance testing was developed as a factored estimate using costs from projects of similar scope. This cost includes the testing, performed by a third-party contractor hired by the Owner, and also includes the cost for S&L's assistance in the following tasks:

a. Development of the test protocol
b. Procuring the services of the testing contractor
c. Overseeing the performance test campaign
d. Evaluating the results of the testing with respect to guarantee compliance

The estimate for the third party testing contractor is based on the assumption that the contractor would be onsite for up to 3 days for each unit.

The total cost of the Performance Testing was estimated to be $275,000 without escalation.

6. Project Contingency

Project contingency is included in the estimate to cover the uncertainty associated with the project costs, and was developed utilizing Entergy's procedure for developing a project's contingency. The process includes developing three components of contingency:

a. Risk Contingency: This category of contingency is developed with the use of a Risk Register that is used to identify risks that may impact the project. Each risk in the Risk Register is analyzed to determine the probability of the risk and the impacts of the risk to the project.

b. Estimate Uncertainty: This category of contingency uses the estimate accuracy classifications to develop an appropriate level of contingency. Entergy has adopted expected accuracy ranges for estimates with upper and lower boundaries for each class of costs estimate. These ranges recognize the uncertainty that exists in the technical engineering and project management deliverables that define scope.

c. Unknown/Emergent Risks: This category of contingency is used to account for any issues that arise during the project that are not contained within the risk register or to cover any costs associated with unanticipated changes in project scope.

A cost qualitative risk assessment (QRA) was performed using Palisade Corporation's @RISK software. QRAs are used to validate the reasonableness of cost estimates, provide confidence for cost projections, and help establish a reasonable level of contingency based on risk-weighted estimates and project risk profiles. The QRA identifies various confidence levels that the contingency amount is sufficient for the project. For this estimate's cost QRA, an 80% confidence level was selected which means the project is 80% likely to be completed at or below the calculated value. The 80% confidence level results in a contingency value of 15% of the total project cost before escalation and IDC. This level of contingency is within Entergy's guidelines for target contingency range for this class of estimate. The contingency estimate is included in Attachment 8.

7. Escalation on Owner's Costs

Escalation was included in the estimate at an escalation rate 3.35% on the Owner's costs. This escalation rate is based on the rate developed by S&L for labor and indirects above.

8. Interest During Construction

Interest during construction (IDC) accounts for the time value of money associated with the distribution of construction cash flows over the construction period. IDC was applied to the total EPC project costs including contingency. The IDC was calculated based on the milestone payment schedule included in Attachment 4 and a typical interest rate of 7.0% per year which was assumed based on a low interest market environment.

4.3 VARIABLE OPERATING AND MAINTENANCE COSTS

The following unit costs were used to develop the variable Operating and Maintenance (O&M) costs. All of these values, with the exception of the reagent costs, were provided by Entergy and are consistent with typical industry values. The reagent costs are based on recent supplier quotes received for White Bluff.

Table 4-1: Unit Pricing for Utilities (Provided by Entergy)

Unit Cost	Units	Value
Pebble Lime	$/ton	$130.0
High Quality Water	$/1000 gal	$2.00
Low Quality Water	$/1000 gal	$0.53
Byproduct Disposal	$/ton	$7.50
Aux Power Cost	$/MWh	$43.35

Table 4-2 below summarizes the consumption rates estimated as well as the first year variable O&M costs for the Dry FGD system.

Table 4-2: Variable O&M Rates and First Year Costs, per Unit

	Units	Design 0.68 lb SO_2/MMBtu
Dry FGD System Parameters		
Reagent Consumption	lb/hr	7,000
Byproduct Waste Production	lb/hr	16,000
Aux Power Consumption	kW	11,000
High Quality Water Consumption	gpm	75
Low Quality Water Consumption	gpm	775
First Year[1] Variable O&M Costs (@CF[2])		
Reagent Cost	$/year	$2,888,000
Byproduct Waste Disposal Cost	$/year	$380,000
Aux Power Cost	$/year	$3,027,000
Water Cost	$/year	$214,000
Bag and Cage Replacement Cost	$/year	$372,000
Total First Year Variable O&M Cost	**$/year**	**$6,881,000**

Note 1: First year costs are provided in $2015.

Note 2: The first year costs are calculated using an annual capacity factor of 72.46%.

4.4 FIXED OPERATING AND MAINTENANCE COSTS

The fixed O&M costs for the systems consist of operating personnel as well as maintenance costs (including material and labor). Based on the conceptual design for the dry FGD system, the estimated staffing additions are 28 personnel for two systems on adjacent units.

The annual maintenance costs are estimated as a percentage of the total capital equipment cost, based on the amount of operating equipment which will require routine maintenance. For this evaluation, the maintenance costs (maintenance and labor) were estimated to be approximately 1.3% of the project capital. This is a lower value than typical because items such as track work and civil work are high capital cost items with little to no maintenance.

Table 4-3 below summarizes the first year fixed O&M costs for the design and typical cases.

Table 4-3: First Year Fixed O&M Costs for Dry FGD, per Unit

First Year[1] Fixed O&M Costs	Units	Design 0.68 lb SO_2/MMBtu
Operating Labor[2]	$/year	$1,660,000
Maintenance Material	$/year	$975,000
Maintenance Labor	$/year	$650,000
Total First Year Fixed O&M Cost	**$/year**	**$3,285,000**

Note 1: First year costs are provided in $2015.

Note 2: Operating labor costs are based on a labor rate of $56.95, which was provided by Entergy.

Note 3: Installation of systems on both units would require 28 operators total. For accounting purposes, this is considered 14 operators per unit.

4.5 SULFUR DESIGN BASIS SENSITIVITY

The average sulfur content of coal received at the White Bluff station is 0.68 lb SO_2/MMBtu; however, the White Bluff station has the ability to receive coal with sulfur content up to 1.2 lb SO_2/MMBtu. In order to provide a system which is capable of meeting the design SO_2 emission rate on a continuous basis through the range of coals delivered to site, the FGD equipment must be designed for the maximum coal sulfur which could be burned in the units.

S&L evaluated the incremental cost impact of designing the FGD system for an inlet sulfur of 1.2 lb SO_2/MMBtu versus a lower inlet sulfur of 0.68 lb SO_2/MMBtu. It is important to note that the majority of the components within the FGD Island are designed to accommodate the maximum volumetric flue gas flowrate from the unit. The size and cost of these components, primarily the absorber vessels, baghouses, and ID fans, remains the same regardless of the inlet design sulfur. In addition, the majority of the BOP scope items which have been included in the capital cost estimate would remain constant regardless of the inlet design sulfur.

The primary equipment which is impacted by the design inlet sulfur would be the reagent handling, reagent preparation, and the waste handling systems. The inlet sulfur has a direct impact on the quantity of SO_2 which is being removed in the FGD system, and therefore a direct impact on the required lime (reagent) consumption rate as well as the quantity of byproduct produced. The following areas and associated equipment are impacted by adjusting the design inlet sulfur:

a. Reagent Storage and Handling System:
   - Two long-term storage silos

b. Reagent Preparation System (FGD Island):
   - Two lime day bins
   - Two detention lime slakers
   - Two lime slurry storage tanks

c. By-product Handling System:
   - Two FGD by-product storage silos

The quantity of byproduct which is recycled through the system to achieve the required performance will remain relatively constant regardless of inlet design sulfur and is therefore not impacted. In addition, the lime slurry and byproduct recycle are continuously circulated in a loop to the units and back to the storage tanks; therefore, a variation in the design sulfur would not significantly impact the sizing of the recycle storage equipment, pumps or piping systems.

The cost differential was determined by vendor quotes who were requested to provide equipment costs for design capacities at each of the design sulfur levels; this is the same approach used to adjust the Alstom budgetary proposal from a design sulfur of 2.0 lb/MMBtu to 1.2 lb/MMBtu for the cost estimate. The following table summarizes the cost differential for the equipment identified above that is impacted by the sulfur design basis:

Equipment	Design Capacity @ 1.2 lb/MMBtu	Design Capacity @ 0.68 lb/MMBtu	Cost Reduction for 1.2 to 0.68 lb/MMBtu[1]
Two long-term storage silos	2,200 tons each	1,200 tons each	- $4,332,000
Two lime day bins	650 tons each	300 tons each	- $272,000

Two detention lime slakers	13 tons/hour each	7 tons/hour each	- $113,000
Two lime slurry storage tanks	2,000 tons each	1,000 tons each	- $373,000
Two FGD by-product storage silos	3,000 tons each	1,750 tons each	- $2,400,000
		TOTAL Differential	**- $7,490,000**

Note 1: Cost Reduction shows the reduction in direct installed capital cost including reductions associated with BOP, i.e. reduced foundation sizes.

The reduction in the total direct installed costs associated with reducing the design sulfur level from 1.2 lb SO_2/MMBtu to 0.68 lb SO_2/MMBtu is approximately $7.5M.

5. SUMMARY

The cost estimate for the White Bluff Units 1&2 Dry FGD systems is based on the addition of two SDA FGD systems for SO_2 removal. The attached capital estimate for the White Bluff Dry FGD system is based on this technical basis.

6. ATTACHMENTS

1. White Bluff DFGD Project Units 1 and 2 Conceptual Capital Cost Estimate, Sargent & Lundy Estimate No. 33387A

2. White Bluff DFGD Project Units 1 and 2 Conceptual Cost Estimate Cash Flow, Sargent & Lundy Estimate No. 33387A

3. White Bluff DFGD Project Units 1 and 2 Level 1 Preliminary Execution Schedule

4. Monthly Progress Payment Schedule for White Bluff DFGD Project

5. S&L Estimating Documentation: Indirects and Construction Equipment included in Crew Rates

6. S&L Estimating Documentation: Escalation Projections

7. White Bluff DFGD Project Units 1 and 2 Conceptual General Arrangement Drawing

8. Entergy Basis of Contingency

ATTACHMENT 1

Conceptual Capital Cost Estimate

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Estimator	A. KOCI
Labor rate table	15ARPBL
Project No.	13027-002
Client	ENTERGY ARKANSAS
Station Name	WHITE BLUFF
Unit	1 & 2
Estimate Date	06/29/2015
Reviewed By	BA
Approved By	MNO
Estimate No.	33387A
Cost index	ARPBL

Project Cost Estimate Totals

Description	Amount	Totals	Hours
Direct Costs:			
Labor	104,382,058		1,309,072
Material	64,284,799		
Subcontract	313,285,100		
Process Equipment	23,517,000		
	505,468,957	**505,468,957**	
Other Direct & Construction Indirect Costs:			
91-1 Scaffolding	7,306,743		
91-2 Cost Due To OT 5-10's	14,545,500		
91-4 Per Diem	13,090,700		
91-5 Consumables	1,043,800		
91-6 Freight on Material	3,214,200		
91-8 Sales Tax	8,928,800		
91-9 Contractors G&A	20,987,700		
91-10 Contractors Profit	10,493,800		
	79,611,243	**585,080,200**	
Indirect Costs:			
93-1 Engineering Services	23,000,000		
93-4 SU/S Parts/ Initial Fills	300,000		
93-5 Technical Field Advisors	600,000		
93-8 EPC Fee	60,898,000		
	84,798,000	**669,878,200**	
Escalation:			
96-1 Escalation on Material	7,632,000		
96-2 Escalation on Labor	23,480,200		
96-3 Escalation on Subcontract	37,428,800		
96-4 Escalation on Process Eq	2,158,600		
96-5 Escalation on Indirects	12,334,500		
	83,034,100	**752,912,300**	
Total EPC Cost		***752,912,300***	
Owner's Costs:			
99-1 Owner's Costs	58,546,000		
	58,546,000	**811,458,300**	
Third Party Services:			
100 CM Oversight	4,969,000		
102 Start-up Oversight	550,000		
103 Owner's Engineer	6,750,000		
104 Performance Testing	275,000		
	12,544,000	**824,002,300**	
Project Contingency :			
110 Project Contingency	111,145,700		
	111,145,700	**935,148,000**	
Escalation Addition:			
120 Escalation on Lines 99-110	2,273,000		
	2,273,000	**937,421,000**	
Interest During Construction:			
130 Interest During Constr.	134,949,000		
	134,949,000	**1,072,370,000**	
Total		***1,072,370,000***	

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Description	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Total Cost
10	FGD ISLAND	297,904,000	(1,649,000)		-7,814	(680,533)	295,574,467
101	FGD ISLAND FOUNDATIONS AND ENCLOSURES			14,838,628	254,893	18,939,033	33,777,661
102	REAGENT HANDLING SYSTEM	6,000,000	2,046,000	3,162,954	59,192	4,646,650	15,855,604
105	BYPRODUCT HANDLING SYSTEM	7,713,100	6,872,000	1,089,675	107,800	7,935,771	23,610,546
111	FLUE GAS SYSTEM		480,000	16,910,288	337,269	29,197,085	46,587,373
121	CIVIL BOP	570,000		8,073,474	106,878	11,535,049	20,178,523
151	MECHANICAL BOP	998,000	1,969,000	6,882,913	115,659	9,189,021	19,038,934
190	DEMOLITION / RELOCATION	100,000		1,578,182	33,735	2,546,302	4,224,484
201	ELECTRICAL BOP SYSTEM		12,299,000	10,665,684	290,576	20,231,688	43,196,372
211	INSTRUMENTATION AND CONTROLS BOP SYSTEM		1,500,000	1,083,000	10,884	841,993	3,424,993
	TOTAL DIRECT	**313,285,100**	**23,517,000**	**64,284,799**	**1,309,072**	**104,382,058**	**505,468,956**

Note: Negative costs included in the cost estimate are due to adjustments to the FGD Budgetary Proposal which was based on a design sulfur of 2.0 lb/MMBTU.
Cost adjustments are included to adjust the design sulfur basis to 1.2 lb/MMBTU.

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
10			FGD ISLAND									
	23.00.00		STEEL									
		23.13.75	SILO									
			SILO - LIME DAY BINS 650 TONS - EQUIPMENT ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS		(273,000)			73.12 /MH		(273,000)
			SILO - LIME DAY BINS 650 TONS - LABOR ONLY	CREDIT FOR REDUCTION FROM 1200 TONS	-2.00 LS				-690	73.12 /MH	(50,428)	(50,428)
			SILO				(273,000)		-690		(50,428)	(323,428)
			STEEL				(273,000)		-690		(50,428)	(323,428)
	31.00.00		MECHANICAL EQUIPMENT									
		31.45.00	FGD EQUIPMENT									
			DRY FGD -UNITS 1 & 2 FGD ISLAND - EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	152,030,000		-		97.28 /MH		152,030,000
			DRY FGD -UNITS 1 & 2 FGD ISLAND - INSTALLATION COST	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	145,874,000		-		97.28 /MH		145,874,000
			DRY FGD - INLUDES ABSORBERS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BAGHOUSES	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES REGEANT PREP EQUIPMENT FROM DAY SILOS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES BYPRODUCT RECYCLE PREPARATION EQUIPMENT	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES ID BOOSTER FANS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES PROCESS INSTRUMENTATION AND DCS	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES INTERCONNECTING WIRING, PIPING ETC... WITHIN FGD ISLAND	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			DRY FGD - INCLUDES DUCTWORK FROM INLET FLANGE TO OUTLET BOOSTER FAN FLANGE	BASED ON ALSTOM BUDGETARY PROPOSAL AUGUST 8, 2013	1.00 LS	-	-	-		/MH		
			FLOW MODEL	INCLUDED WITH ALSTOM PROPOSAL	1.00 LT	-		-		/MH		
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - EQUIPMENT ONLY	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-	(1,300,000)	-		90.81 /MH		(1,300,000)
			REAGENT PREPARATION - LIME SLURRY FEED TANKS - LABOR	REDUCTION IN SIZE TO 2000 TON FROM 3900 TONS BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 LT	-		-	-6,370	90.81 /MH	(578,470)	(578,470)
			FGD EQUIPMENT			297,904,000	(1,300,000)		-6,370		(578,470)	296,025,530
			MECHANICAL EQUIPMENT			297,904,000	(1,300,000)		-6,370		(578,470)	296,025,530
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - EQUIPMENT ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-	(76,000)	-		68.48 /MH		(76,000)
			MATERIAL HANDLING SYSTEM - LIME SLAKING TRAIN - REDUCTION FROM 25 TPH TO 13 TPH - LABOR ONLY	CREDIT BASED ON ALSTOM SDA BUDGETARY PROPOSAL 8/2013	-2.00 EA	-		-	-754	68.48 /MH	(51,635)	(51,635)
			MATERIAL HANDLING EQUIPMENT				(76,000)		-754		(51,635)	(127,635)
			MATERIAL HANDLING EQUIPMENT				(76,000)		-754		(51,635)	(127,635)
			10 FGD ISLAND			297,904,000	(1,649,000)		-7,814		(680,533)	295,574,467
101			FGD ISLAND FOUNDATIONS AND ENCLOSURES									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 BAGHOUSE FDN	252.00 EA	-	-	480,816	6,662	108.46 /MH	722,568	1,203,384
			PILING					961,632	13,324		1,445,136	2,406,768
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	ABSORBER TOWERS FOUNDATIONS	180.00 EA	-	-	334,260	4,552	108.46 /MH	493,680	827,940
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	50.00 EA	-	-	92,850	1,264	108.46 /MH	137,133	229,983
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	72.00 EA	-	-	133,704	1,821	108.46 /MH	197,472	331,176
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 1 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			2.5 FT DIA X 30 FT DEEP CAISSON	UNIT 2 BOOSTER FAN FOUNDATION	40.00 EA	-	-	74,280	1,011	108.46 /MH	109,707	183,987
			CAISSON					1,043,634	14,211		1,541,379	2,585,013

Exhibit B to EAI Comments

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			CIVIL WORK					**2,005,266**	**27,536**		**2,986,515**	**4,991,781**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	REAGENT PREP ENCLOSURE 50'X50' SUBSTRUCTURE	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	BYPRODUCTS RECYCLE EQUIPMENT BLDG 60' X 60' SUBSTRUCTURE	432.00 CY	-	-	99,360	3,476	59.71 /MH	207,544	306,904
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 1 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	UNIT 2 BOOSTER FAN FOUNDATION	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWER FOUNDATION	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ABSORBER TOWERS FOUNDATIONS	1,300.00 CY	-	-	299,000	10,460	59.71 /MH	624,553	923,553
			CONCRETE FOUNDATIONS - COMPOSITE RATE	LIME SLURRY FEED TANKS	400.00 CY	-	-	92,000	3,218	59.71 /MH	192,170	284,170
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 1 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS - COMPOSITE RATE	UNIT 2 BAGHOUSE FDN 3 FDNS 83'X63'X3'	1,743.00 CY	-	-	400,890	14,024	59.71 /MH	837,381	1,238,271
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE					**1,938,900**	**67,828**		**4,049,985**	**5,988,885**
			CONCRETE					**1,938,900**	**67,828**		**4,049,985**	**5,988,885**
	23.00.00		**STEEL**									
		23.17.00	**GALLERY**									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	4,000.00 SF	-	-	60,000	460	66.07 /MH	30,377	90,377
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	BYPRODUCTS RECYCLE EQUIPMENT BLDG	5,760.00 SF	-	-	86,400	662	66.07 /MH	43,743	130,143
			3" HEAVY DUTY GRATING	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	200.00 SF	-	-	11,200	39	66.07 /MH	2,582	13,782
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	3,000.00 LF	-	-	159,000	621	66.07 /MH	41,009	200,009
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	4,320.00 LF	-	-	228,960	894	66.07 /MH	59,053	288,013
			SELF CLOSING SWING GATE - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	40.00 EA	-	-	11,200	184	66.07 /MH	12,151	23,351
			SELF CLOSING SWING GATE - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	58.00 EA	-	-	16,240	267	66.07 /MH	17,619	33,859
			LADDER	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	800.00 LF	-	-	40,000	368	66.07 /MH	24,302	64,302
			LADDER	BYPRODUCTS RECYCLE EQUIPMENT BLDG	1,100.00 LF	-	-	55,000	506	66.07 /MH	33,415	88,415
			STAIR SYSTEM	REAGENT PREP ENCLOSURE 50'X50' SUPERSTRUCTURE	2,400.00 SF	-	-	218,400	3,172	66.07 /MH	209,601	428,001
			STAIR SYSTEM	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,500.00 SF	-	-	318,500	4,626	66.07 /MH	305,669	624,169
			GALLERY					**1,204,900**	**11,798**		**779,520**	**1,984,420**
		23.25.00	**ROLLED SHAPE**									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	REAGENT PREP ENCLOSURE 50'X50' GALLERY SUPPORT	200.00 TN	-	-	716,000	5,057	92.62 /MH	468,423	1,184,423
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	BYPRODUCTS RECYCLE EQUIPMENT BLDG	288.00 TN	-	-	1,031,040	7,283	92.62 /MH	674,529	1,705,569
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U1 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, GALVANIZED	U2 BAGHOUSE SKIRTS STEEL GIRTS	36.00 TN	-	-	138,240	910	92.62 /MH	84,316	222,556
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED		50.00 TN	-	-	128,000	920	92.62 /MH	85,168	213,168
			BUILDING MIX, TWO COAT PAINTED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	500.00 TN	-	-	1,280,000	9,195	92.62 /MH	851,678	2,131,678
			BUILDING MIX, TWO COAT PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	720.00 TN	-	-	1,843,200	13,241	92.62 /MH	1,226,417	3,069,617
			ROLLED SHAPE					**5,402,720**	**38,437**		**3,560,015**	**8,962,735**
			STEEL					**6,607,620**	**50,235**		**4,339,534**	**10,947,154**
	24.00.00		**ARCHITECTURAL**									
		24.17.00	**ELEVATOR**									
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296
			PASSENGER, TRACTION, 4 STOPS, 3500LB, 350 FT/MIN	SCHINDLER ELEVATOR BUDGET	1.00 LS	-	-	159,350	943	106.04 /MH	99,946	259,296

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			ELEVATOR					318,700	1,885		199,892	518,592
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 1 BAGHOUSE AREA, COMPRESSOR BLDG	1.00 LT	-	-	20,000	115	92.62 /MH	10,646	30,646
			PRE-ENGINEERED BUILDING	8' X 10' UNIT 2 BAGHOUSE AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					30,000	230		21,292	51,292
		24.37.00	ROOFING									
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U1 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED, 2 IN GALVANIZED, PAINTED, 22 GA	U2 SDA TOP ENCLOSURE ROOF	3,318.00 SF	-	-	54,946	339	35.02 /MH	11,887	66,833
			METAL, INSULATED- USER DEFINED	REAGENT PREP ENCLOSURE SUPERSTRUCTURE	2,500.00 SF	-	-	19,425	862	35.02 /MH	30,190	49,615
			METAL, INSULATED- USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	3,600.00 SF	-	-	27,972	1,241	35.02 /MH	43,473	71,445
			ROOFING					157,289	2,782		97,436	254,725
		24.41.00	SIDING									
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U1 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	U2 SDA TOP ENCLOSURE SIDING	2,450.00 SF	-	-	40,572	251	79.59 /MH	19,948	60,520
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	REAGENT PREP ENCLOSURE	10,000.00 SF	-	-	165,600	1,023	79.59 /MH	81,420	247,020
			METAL, INSULATED, 2 IN THICK FIBERGLASS, 22 GA, GALVANIZED PAINTED	BYPRODUCTS RECYCLE EQUIPMENT BLDG	14,400.00 SF	-	-	238,464	1,473	79.59 /MH	117,244	355,708
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U1 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,260.00 SF	-	-	85,345	1,238	79.59 /MH	98,496	183,841
			METAL, UNINSULATED, 24 GA, GALVANIZED CORROGATED	U2 BAGHOUSE SKIRTS 6x(83'+63) x30' tall '	26,280.00 SF	-	-	85,410	1,238	79.59 /MH	98,571	183,981
			SIDING					655,963	5,473		435,626	1,091,589
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			PENTHOUSE HEATING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U1 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			PENTHOUSE HEATING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	64.10 /MH	4,715	68,715
			PENTHOUSE LIGHTING	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	64,000	74	82.05 /MH	6,036	70,036
			PENTHOUSE FIRE PROTECTION	U2 SDA SUPERSTRUCTURE	6,400.00 SF	-	-	32,000	37	82.05 /MH	3,018	35,018
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U1 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS - USER DEFINED	U2 BAGHOUSE SKIRTS MANDOORS	3.00 EA	-	-	1,500	28	51.10 /MH	1,410	2,910
			ARCHITECTURAL, MISCELLANEOUS					323,000	423		30,358	353,358
			ARCHITECTURAL					1,484,952	10,794		784,604	2,269,556
	31.00.00		MECHANICAL EQUIPMENT									
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	REAGENT PREP ENCLOSURE 50'X50' FIRE PROTECTION ALLOWANCE	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	BYPRODUCTS RECYCLE EQUIPMENT BLDG' FIRE PROTECTION ALLOWANCE	10,800.00 SF	-	-	59,400	832	68.48 /MH	56,956	116,356
			FIRE PROTECTION EQUIPMENT & SYSTEM					86,900	1,217		83,325	170,225
		31.83.00	TANK									
			TANK - MOVE OIL TANK FROM USED OIL SHED AND REINSTALL AT WASTE MANAGEMENT FACILITY	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 EA	-	-	-	345	90.81 /MH	31,314	31,314
			TANK						345		31,314	31,314
			MECHANICAL EQUIPMENT					86,900	1,562		114,639	201,539
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	64.10 /MH	3,684	58,684
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	64.10 /MH	7,957	126,757
			HVAC, MISCELLANEOUS					173,800	182		11,641	185,441
			HVAC					173,800	182		11,641	185,441
	36.00.00		INSULATION									
		36.13.00	DUCT									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U1 BAGHOUSE INSUILATION TOP, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 4 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	U2 BAGHOUSE INSULATIOIN - TOPS, SIDES AND HOPPERS	141,831.00 SF	-	-	850,986	35,050	68.76 /MH	2,410,051	3,261,037
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA SHELL INSULATION	40,167.00 SF	-	-	261,086	10,388	68.76 /MH	714,280	975,366
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	SDA ROOF INSULATION	11,019.00 SF	-	-	71,624	2,850	68.76 /MH	195,948	267,572
			DUCT					2,367,390	96,576		6,640,559	9,007,949
			INSULATION					2,367,390	96,576		6,640,559	9,007,949
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	REAGENT PREP ENCLOSURE 50'X50' LIGHTING ALLOWANCE	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	BYPRODUCTS RECYCLE EQUIPMENT BLDG LIGHTING ALLOWANCE	10,800.00 SF	-	-	118,800	124	63.63 /MH	7,899	126,699
			LIGHTING ACCESSORY (FIXTURE)					173,800	182		11,556	185,356
			ELECTRICAL EQUIPMENT					173,800	182		11,556	185,356
			101 FGD ISLAND FOUNDATIONS AND ENCLOSURES					**14,838,628**	**254,893**		**18,939,033**	**33,777,661**
102			**REAGENT HANDLING SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNLOADING SHED 200' X 75 WIDE	63.00 EA	-	-	120,204	1,666	108.46 /MH	180,642	300,846
			PILING					120,204	1,666		180,642	300,846
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	SUBSTRUCTURE 2200 TON LIME STORAGE SILOS	100.00 EA	-	-	185,700	2,529	108.46 /MH	274,267	459,967
			CAISSON					185,700	2,529		274,267	459,967
		21.71.00	TRACKWORK									
			RAIL, TIE & BALLAST - 136 LB/YD	REAGENT HANDLING SYSTEM UPGRADE AND EXTEND LIME RAIL TRACK TO AVOID BLOCKING ACCESS BY 150 CAR COAL TRAINS	9,060.00 TF	-	-	1,540,200	15,621	81.27 /MH	1,269,493	2,809,693
			TRACKWORK - EXTEND LIME RAIL SPUR AND RELOCATE SWITCH 2060 FT	RELOCATE COAL TRACK SWITCH TO WEST TO AVOID INTERFERENCE WITH 150 CAR COAL TRAINS	1.00 LS	-	-	374,000	7,989	81.27 /MH	649,226	1,023,226
			TRACKWORK					1,914,200	23,609		1,918,719	3,832,919
			CIVIL WORK					2,220,104	27,803		2,373,628	4,593,732
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	SUBSTRUCTURE 2-2200 TON LIME STORAGE SILOS	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			FOUNDATION, 4500 PSI - COMPOSITE RATE	UNLOADING SHED 200' X 75 WIDE	925.00 CY	-	-	212,750	7,443	59.71 /MH	444,393	657,143
			CONCRETE					350,750	12,270		732,649	1,083,399
			CONCRETE					350,750	12,270		732,649	1,083,399
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	UNLOADING SHED 200' X 75 WIDE x15' TALL	15,000.00 SF	-	-	525,000	4,828	92.62 /MH	447,131	972,131
			PRE-ENGINEERED BUILDING					525,000	4,828		447,131	972,131
			ARCHITECTURAL					525,000	4,828		447,131	972,131
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 2200 TON LIME STORAGE SILO	ERECTED - 46' DIA X 154' TALL EA - OPTION 2	2.00 LS	6,000,000				59.71 /MH		6,000,000

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO			6,000,000			0			6,000,000
			MISCELLANEOUS STRUCTURAL ITEM			6,000,000			0			6,000,000
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			CRANES & HOISTS - & TROLLEYS ALLOWANCE	REAGENT HANDLING SYSTEM	1.00 LT	-	275,000	-		68.48 /MH		275,000
			CRANES & HOISTS				275,000					275,000
			MECHANICAL EQUIPMENT				275,000					275,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.14.00	MATERIAL HANDLING EQUIPMENT									
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - VACUUM EXHAUSTER WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	2.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - RECEIVING PANS UNDER RAIL CARS	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - FILTER SEPARATORS ON TOP OF SILO	INCLUDED WITH 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - 25 TPH PNEUMATIC TRANSPORT SYSTEM		1.00 LS	-	500,000	-	3,306	68.48 /MH	226,378	726,378
			LIME HANDLING SYSTEM - PRESSURE BLOWERS WITH SOUND ENCLOSURES	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	3.00 LS	-		-		/MH		
			LIME HANDLING SYSTEM - PRESSURE FEEDERS	INCLUDED WITH 25 TPH PNEUMATIC TRANSPORT SYSTEM	1.00 LS	-	-	-		/MH		
			LIME HANDLING SYSTEM - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	8,000	-		68.48 /MH		8,000
			LIME HANDLING SYSTEM - FREIGHT		1.00 LS	-	50,000	-		68.48 /MH		50,000
			MATERIAL HANDLING EQUIPMENT				1,058,000		6,611		452,755	1,510,755
		33.41.00	MOBILE YARD EQUIPMENT									
			MOBILE YARD EQUIPMENT - TRACKMOBILE	REAGENT HANDLING SYSTEM	1.00 EA	-	225,000	-		68.48 /MH		225,000
			MOBILE YARD EQUIPMENT				225,000					225,000
		33.51.00	RAIL CAR UNLOADER									
			RAIL CAR UNLOADER -	IN UNLOADING SHED 200'X75' WIDE	1.00 LT	-	225,000	-	3,103	92.62 /MH	287,441	512,441
			RAIL CAR UNLOADER				225,000		3,103		287,441	512,441
			MATERIAL HANDLING EQUIPMENT				1,508,000		9,715		740,197	2,248,197
	34.00.00		HVAC									
		34.99.00	HVAC, MISCELLANEOUS									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	2-2200 TON LIME STORAGE SILOS	3,600.00 SF	-	-	39,600	41	64.10 /MH	2,652	42,252
			HVAC, MISCELLANEOUS					39,600	41		2,652	42,252
			HVAC					39,600	41		2,652	42,252
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			8 IN DIA, SCH 40, 8" VACUUM CONVEY PIPING WITH 4 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRAIN UNLOADING SYSTEM	500.00 LF	-	38,000		540	77.36 /MH	41,792	79,792
			12 IN DIA, 3/8 IN STD- 2500 LF OF 10"/12" TRANSPORT PRESSURE PIPING W 8 ELBOWS	TO SUPPORT 25 TPH PNEUMATIC TRANSPORT SYSTEM	2,500.00 LF	-	225,000		3,966	77.36 /MH	306,772	531,772
			CARBON STEEL, STRAIGHT RUN				263,000		4,506		348,565	611,565
			PIPING				263,000		4,506		348,565	611,565
	41.00.00		ELECTRICAL EQUIPMENT									
		41.37.00	LIGHTING ACCESSORY (FIXTURE)									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	4200 TON LIME STORAGE SILO	2,500.00 SF	-	-	27,500	29	63.63 /MH	1,828	29,328
			LIGHTING ACCESSORY (FIXTURE)					27,500	29		1,828	29,328
			ELECTRICAL EQUIPMENT					27,500	29		1,828	29,328
			102 REAGENT HANDLING SYSTEM			**6,000,000**	**2,046,000**	**3,162,954**	**59,192**		**4,646,650**	**15,855,604**
105			**BYPRODUCT HANDLING SYSTEM**									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	ASH SILO AND FGD BYPRODUCT SILOS	125.00 EA	-	-	232,125	3,161	108.46 /MH	342,833	574,958
			CAISSON					232,125	3,161		342,833	574,958
			CIVIL WORK					232,125	3,161		342,833	574,958
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FGD BYPRODUCT SILOS	614.00 CY	-	-	141,220	4,940	59.71 /MH	294,981	436,201
			MAT FOUNDATION LESS THAN 5FT THICK, 4500 PSI - COMPOSITE RATE	FLY ASH BLENDING SILO	67.00 CY	-	-	15,410	539	59.71 /MH	32,188	47,598
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	FOR TRUCK SCALES	144.00 CY	-	-	33,120	1,159	59.71 /MH	69,181	102,301
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	MISC	100.00 CY	-	-	23,000	805	59.71 /MH	48,043	71,043
			CONCRETE					212,750	7,443		444,393	657,143
			CONCRETE					212,750	7,443		444,393	657,143
	23.00.00		STEEL									
		23.13.75	SILO									
			NEW 250 TON FLYASH BLENDING BIN SILO - 24FT DIA X 72 FT HIGH - ERECTION AND FREIGHT INCLUDED	SILO	1.00 EA		275,000		2,839	73.12 /MH	207,594	482,594
			SILO				275,000		2,839		207,594	482,594
			STEEL				275,000		2,839		207,594	482,594
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.13.00	CONCRETE SILO									
			CONCRETE SILO - 3000 TON FGD BYPRODUCT SILO	ERECTED - 52' DIA X 162' TALL EA	2.00 LS	7,600,000				59.71 /MH		7,600,000
			CONCRETE SILO - BIN VENT FILTERS	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - LEVEL INDICATOR	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - VACUUM PRESSURE RELIEF VALVE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - MANHOLE	INCLUDED W/ SILO	1.00 LS	-	-		0	/MH		
			CONCRETE SILO - SPARE PARTS FOR STARTUP AND SPECIAL TOOLS		1.00 LS	-	10,000			73.12 /MH		10,000
			CONCRETE SILO - FREIGHT		1.00 LS	-	70,000			73.12 /MH		70,000
			CONCRETE SILO			7,600,000	80,000		0			7,680,000
			MISCELLANEOUS STRUCTURAL ITEM			7,600,000	80,000		0			7,680,000
	33.00.00		MATERIAL HANDLING EQUIPMENT									
		33.13.00	BYPRODUCT HANDLING EQUIPMENT									
			PNEUMATIC ASH CONVEYORS	EQUIPMENT INCLUDES FREIGHT	1.00 LS	-	5,655,000	-		73.12 /MH		5,655,000
			PNEUMATIC ASH CONVEYORS	INSTALLATION COST	1.00 LT	-		-	79,293	73.12 /MH	5,797,912	5,797,912
			BLOWERS, PRESSURE FEEDERS, TRANSPORT PIPING AND VACUUM / PRESSURE RELIEF VALVES	INCLUDED ABOVE	1.00 LT	-		-		73.12 /MH		
			-FOUR PIN MIXERS BELOW CONCRETE SILOS INCL ALL VALVES AND ACCESSORIES		1.00 LT	-	540,000	-	3,347	73.12 /MH	244,742	784,742
			-DRY UNLOADING SPOUT BELOW THE PRODUCT SILO		2.00 EA	-	60,000	-	258	73.12 /MH	18,877	78,877
			AIRSLIDE CONVEYORS FROM BLENDING BIN MIXER/PIPE CONVEYOR, INCL ALL VALVES AND ACCESSORIES		4.00 EA	-	80,000	-	688	73.12 /MH	50,327	130,327
			BYPRODUCT HANDLING EQUIPMENT				6,335,000		83,587		6,111,857	12,446,857
		33.57.00	SCALE									
			SCALE - NEW TRUCK SCALES	BYPRODUCT HANDLING SYSTEM	2.00 EA	-	182,000	-	460	68.48 /MH	31,485	213,485
			SCALE				182,000		460		31,485	213,485
			MATERIAL HANDLING EQUIPMENT				6,517,000		84,046		6,143,342	12,660,342
	34.00.00		HVAC									
		34.37.00	DUST COLLECTOR									
			DUST COLLECTOR - INSTALLED COST		1.00 LS	113,100	-			64.10 /MH		113,100
			DUST COLLECTOR			113,100						113,100
			HVAC			113,100						113,100
	35.00.00		PIPING									
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	CONVEYOR PIPING	5,000.00 LF	-	-	496,000	7,931	77.36 /MH	613,545	1,109,545
			12 IN DIA, 3/8 IN STD	12" TIE IN PIPING TO BYPRODUCT SILO	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.14.10	CARBON STEEL, STRAIGHT RUN									
			12 IN DIA, 3/8 IN STD	FROM THE EXISTING 50 TPH FLY ASH PRESSURE SYSTEM	1,500.00 LF	-	-	148,800	2,379	77.36 /MH	184,063	332,863
			CARBON STEEL, STRAIGHT RUN					644,800	10,310		797,608	1,442,408
			PIPING					644,800	10,310		797,608	1,442,408
			105 BYPRODUCT HANDLING SYSTEM			**7,713,100**	**6,872,000**	**1,089,675**	**107,800**		**7,935,771**	**23,610,546**
111			**FLUE GAS SYSTEM**									
	21.00.00		CIVIL WORK									
		21.53.00	PILING									
			PILE - 18" AUGER CAST X 60' LONG	UNIT 1 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILE - 18" AUGER CAST X 60' LONG	UNIT 2 FLUE GAS SYSTEM	138.00 EA	-	-	263,304	3,648	108.46 /MH	395,692	658,996
			PILING					526,608	7,297		791,384	1,317,992
			CIVIL WORK					526,608	7,297		791,384	1,317,992
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 1 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	UNIT 2 FLUE GAS SYSTEM	966.00 CY	-	-	222,180	7,772	59.71 /MH	464,091	686,271
			CONCRETE					444,360	15,545		928,182	1,372,542
			CONCRETE					444,360	15,545		928,182	1,372,542
	23.00.00		STEEL									
		23.15.00	DUCTWORK									
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 1 FLUE GAS SYSTEM - MATERIAL NOT COVERED BY ALSTOM	867.40 TN	-	-	2,819,050	59,821	97.25 /MH	5,817,562	8,636,612
			PANEL CONSTRUCTION, DUCT PLATE WITH STIFFENERS, INTERNAL TRUSSES, AND TURNING VANES	UNIT 2 FLUE GAS SYSTEM - MATERIAL NOT COVERED BY ALSTOM	867.40 TN	-	-	2,819,050	59,821	97.25 /MH	5,817,562	8,636,612
			DUCTWORK					5,638,100	119,641		11,635,124	17,273,224
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 1 FLUE GAS SYSTEM	1,308.00 TN	-	-	3,544,680	45,103	92.62 /MH	4,177,481	7,722,161
			ROLLED SHAPE GIRDER - USER DEFINED	UNIT 2 FLUE GAS SYSTEM	1,308.00 TN	-	-	3,544,680	45,103	92.62 /MH	4,177,481	7,722,161
			GIRDER					7,089,360	90,207		8,354,963	15,444,323
			STEEL					12,727,460	209,848		19,990,087	32,717,547
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - CHIMNEY	UNIT 1 FLUE GAS SYSTEM	1.00 LT	-	-	110,000	4,109	47.61 /MH	195,639	305,639
			PAINTING					110,000	4,109		195,639	305,639
			PAINTING & COATING					110,000	4,109		195,639	305,639
	31.00.00		MECHANICAL EQUIPMENT									
		31.27.00	DAMPERS & ACCESSORIES									
			DAMPERS & ACCESSORIES - USER DEFINED	UNIT 1 FLUE GAS SYSTEM	800.00 SF	-	240,000		1,471	97.25 /MH	143,080	383,080
			DAMPERS & ACCESSORIES - USER DEFINED	UNIT 2 FLUE GAS SYSTEM	800.00 SF	-	240,000		1,471	97.25 /MH	143,080	383,080
			DAMPERS & ACCESSORIES				480,000		2,943		286,161	766,161
		31.33.00	EXPANSION JOINT									
			EXPANSION JOINT	UNIT 1 FLUE GAS SYSTEM	1,830.00 LF	-		457,500	5,259	97.25 /MH	511,401	968,901
			EXPANSION JOINT	UNIT 2 FLUE GAS SYSTEM	1,830.00 LF	-		457,500	5,259	97.25 /MH	511,401	968,901
			EXPANSION JOINT					915,000	10,517		1,022,802	1,937,802
			MECHANICAL EQUIPMENT				480,000	915,000	13,460		1,308,963	2,703,963
	36.00.00		INSULATION									
		36.13.00	DUCT									
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 1 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			MINERAL WOOL INSULATION, 6 IN THICK, 8 LB/CF DENSITY, ALUMINUM LAGGING, INSTALLED IN PLACE	UNIT 2 FLUE GAS SYSTEM	168,220.00 SF	-	-	1,093,430	43,505	68.76 /MH	2,991,416	4,084,846
			DUCT					2,186,860	87,010		5,982,831	8,169,691
			INSULATION					2,186,860	87,010		5,982,831	8,169,691

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			111 FLUE GAS SYSTEM				**480,000**	**16,910,288**	**337,269**		**29,197,085**	**46,587,373**
121			**CIVIL BOP**									
	21.00.00		**CIVIL WORK**									
		21.14.00	**STRIP & STOCKPILE TOPSOIL**									
			STRIP & STOCKPILE TOPSOIL - 12"		300,000.00 SF	-	-		690	182.33 /MH	125,745	125,745
			STRIP & STOCKPILE TOPSOIL - ONSITE		40,000.00 CY	-	-		5,287	182.33 /MH	964,044	964,044
			STRIP & STOCKPILE TOPSOIL - 12"	SITE GRADING	600,000.00 SF	-	-		1,379	182.33 /MH	251,490	251,490
			STRIP & STOCKPILE TOPSOIL - ONSITE	SITE GRADING	160,000.00 CY	-	-		21,149	182.33 /MH	3,856,175	3,856,175
			STRIP & STOCKPILE TOPSOIL						**28,506**		**5,197,453**	**5,197,453**
		21.17.00	**EXCAVATION**									
			MASS EXCAVATION, COMMON EARTH USING 1.5 CY BACKHOE AND (6) 12 CY DUMP TRUCKS, 4 MI ROUNDTRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		523	182.33 /MH	95,356	95,356
			EXCAVATION - EXCAVATION , BACKFILL & COMPACT ALL FOUNDATIONS		12,600.00 CY	-	-		4,345	79.31 /MH	344,588	344,588
			EXCAVATION						**4,868**		**439,945**	**439,945**
		21.19.00	**DISPOSAL**									
			DISPOSAL OF EXCESS MATERIAL USING DUMP TRUCK, 4 MI ROUND TRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	7,000.00 CY	-	-		483	79.31 /MH	38,288	38,288
			DISPOSAL						**483**		**38,288**	**38,288**
		21.20.00	**BACKFILL**									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,000.00 CY	-	-		172	79.31 /MH	13,674	13,674
			BACKFILL						**172**		**13,674**	**13,674**
		21.39.00	**STORM DRAINAGE UTILITIES**									
			STORM SEWER WORK	SITE GRADING	1.00 LT	-	-	110,000	2,299	72.14 /MH	165,839	275,839
			STORM DRAINAGE UTILITIES					**110,000**	**2,299**		**165,839**	**275,839**
		21.41.00	**EROSION AND SEDIMENTATION CONTROL**									
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK		33,334.00 SY	-	-	355,007	1,149	97.31 /MH	111,853	466,860
			CRUSHED ROCK SURFACING, 12" DEEP WHITE ROCK	SITE GRADING	66,667.00 SY	-	-	710,004	2,299	97.31 /MH	223,702	933,706
			EROSION AND SEDIMENTATION CONTROL					**1,065,011**	**3,448**		**335,555**	**1,400,566**
		21.57.00	**ROAD, PARKING AREA, & SURFACED AREA**									
			BITUMINOUS ROAD - ROAD UPGRADE	BYPRODUCT HAUL ROAD - EAST OF COAL PILE	10,000.00 LF	-	-	500,000	8,046	78.37 /MH	630,563	1,130,563
			BITUMINOUS ROAD - ELIMINATE CHICANE CURVES AT LOW PRESSURE SERVICE WATER PUMPS		1.00 LT	-	-	500,000		78.37 /MH		500,000
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ROADWORK 24' WIDE 4" ASPHALT	SITE GRADING	1,668.00 LF	-	-	201,828	2,013	78.37 /MH	157,767	359,595
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW BYPASS LANE (ON WEST SIDE)	9,000.00 LF	-	-	603,000	1,655	78.37 /MH	129,716	732,716
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW LEFT TURN LANE (SOUTH BOUND)	3,000.00 LF	-	-	201,000	552	78.37 /MH	43,239	244,239
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW MERGE LANE (NORTH BOUND)	4,175.00 LF	-	-	279,725	768	78.37 /MH	60,174	339,899
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	HWY 365, NEW RIGHT TURN LANE (NORTH BOUND)	4,000.00 LF	-	-	268,000	736	78.37 /MH	57,651	325,651
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), UPGRADE, REMOVE EXISTING ASPHALT, SUBGRADE PREP NEW BASE AND NEW ASPHALT	4,250.00 LF	-	-	514,250	3,126	78.37 /MH	245,019	759,269
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	CONTRACTOR HAUL ROAD (HWY 46 SPUR), EXTENSION, 24' WIDE	580.00 LF	-	-	84,100	907	78.37 /MH	71,055	155,155
			BITUMINOUS ASPHALT (200,000 SF AND ABOVE)	WIDENING OF EXISTING MAIN PLANT ROAD FROM CONTRACTOR HAUL ROAD (HWY 46 SPUR) TO MAIN GUARD HOUSE	2,900.00 LF	-	-	194,300	1,767	78.37 /MH	138,454	332,754
			ROAD, PARKING AREA, & SURFACED AREA					**3,346,203**	**19,569**		**1,533,638**	**4,879,841**
		21.71.00	**TRACKWORK**									
			SIGNAL SYSTEM - RR CROSSING SIGNALS AND GATES	CONTRACTOR HAUL ROAD (HWY 46 SPUR) CROSSING	1.00 LS	220,000	-			/MH		220,000
			TRACKWORK			**220,000**						**220,000**
		21.99.00	**CIVIL WORK, MISCELLANEOUS**									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.99.00	CIVIL WORK, MISCELLANEOUS									
			CIVIL WORK - CONSTRUCTION LAYDOWN AREAS	FENCING, POWER ETC...	10.00 AC	-	-	780,000	9,195	79.31 /MH	729,287	1,509,287
			CIVIL WORK, MISCELLANEOUS					780,000	9,195		729,287	1,509,287
			CIVIL WORK			220,000		5,301,214	68,540		8,453,679	13,974,892
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	75.00 CY	-	-	17,250	603	59.71 /MH	36,032	53,282
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	555.00 CY	-	-	127,650	4,466	59.71 /MH	266,636	394,286
			CONCRETE FOUNDATIONS - COMPOSITE RATE	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	6.00 CY	-	-	1,380	48	59.71 /MH	2,883	4,263
			CONCRETE FOUNDATIONS	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	1,800.00 CY	-	-	216,000	2,586	59.71 /MH	154,422	370,422
			CONCRETE					362,280	7,703		459,973	822,253
		22.15.00	EMBEDMENT									
			EMBEDMENTS, CARBON STEEL	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	10,000.00 LB	-	-	30,000	575	51.10 /MH	29,368	59,368
			EMBEDMENT					30,000	575		29,368	59,368
		22.17.00	FORMWORK									
			BUILT UP INSTALL & STRIP	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	11,000.00 SF	-	-	27,500	2,529	81.61 /MH	206,370	233,870
			FORMWORK					27,500	2,529		206,370	233,870
		22.25.00	REINFORCING									
			UNCOATED A615 GR60	2 CELL PROCESS WATER RETENTION POND, 220' X 150' X 7'9"	135.00 TN	-	-	138,375	2,793	56.35 /MH	157,391	295,766
			REINFORCING					138,375	2,793		157,391	295,766
			CONCRETE					558,155	13,600		853,102	1,411,257
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA, 45 FT X 45 FT	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	56,700	791	92.62 /MH	73,298	129,998
			SHELL ONLY, STEEL UNINSULATED 22 GA, 200 FT X 75 FT x 15' TALL	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	420,000	5,862	92.62 /MH	542,945	962,945
			PRE-ENGINEERED BUILDING	8' X 10' BYPRODUCT AREA, TRUCK SCALE HOUSE	1.00 LT	-	-	10,000	115	92.62 /MH	10,646	20,646
			PRE-ENGINEERED BUILDING					486,700	6,768		626,888	1,113,588
		24.41.00	SIDING									
			INSULATION, 2 IN THICK FIBERGLASS,	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	3,240.00 SF	-	-	3,888	37	79.59 /MH	2,964	6,852
			INSULATION, 2 IN THICK FIBERGLASS,	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	8,250.00 SF	-	-	9,900	95	79.59 /MH	7,547	17,447
			SIDING					13,788	132		10,511	24,299
			ARCHITECTURAL					500,488	6,900		637,400	1,137,888
	26.00.00		MISCELLANEOUS STRUCTURAL ITEM									
		26.99.00	MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS									
			MISCELLANEOUS STRUCTURAL ITEM - WATER INTAKE PUMP STRUCTURE - ONE BAY		1.00 LS	-	-	1,110,000	15,537	92.62 /MH	1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM, MISCELLANEOUS					1,110,000	15,537		1,439,017	2,549,017
			MISCELLANEOUS STRUCTURAL ITEM					1,110,000	15,537		1,439,017	2,549,017
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	15,000	172	47.61 /MH	8,209	23,209
			PAINTING					15,000	172		8,209	23,209
			PAINTING & COATING					15,000	172		8,209	23,209

Exhibit B to EAI Comments

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.41.00	**FIRE PROTECTION EQUIPMENT & SYSTEM**									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	11,138	156	68.48 /MH	10,679	21,817
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, FIRE PROTECTION ALLOWANCE	15,000.00 SF	-	-	82,500	1,155	68.48 /MH	79,106	161,606
			FIRE PROTECTION EQUIPMENT & SYSTEM					**93,638**	**1,311**		**89,786**	**183,423**
			MECHANICAL EQUIPMENT					**93,638**	**1,311**		**89,786**	**183,423**
	34.00.00		**HVAC**									
		34.99.00	**HVAC, MISCELLANEOUS**									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	64.10 /MH	1,492	23,767
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	165,000	172	64.10 /MH	11,052	176,052
			HVAC, MISCELLANEOUS					**187,275**	**196**		**12,544**	**199,819**
			HVAC					**187,275**	**196**		**12,544**	**199,819**
	36.00.00		**INSULATION**									
		36.99.00	**INSULATION, MISCELLANEOUS**									
			INSULATION - ROOF INSULATION	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,430	23	51.10 /MH	1,189	3,619
			INSULATION - ROOF INSULATION	NEW WAREHOUSE BUILDING 200'X75'X15' TALL	15,000.00 SF	-	-	18,000	172	51.10 /MH	8,810	26,810
			INSULATION, MISCELLANEOUS					**20,430**	**196**		**10,000**	**30,430**
			INSULATION					**20,430**	**196**		**10,000**	**30,430**
	41.00.00		**ELECTRICAL EQUIPMENT**									
		41.37.00	**LIGHTING ACCESSORY (FIXTURE)**									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	22,275	23	63.63 /MH	1,481	23,756
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW WAREHOUSE BUILDING 200'X75'X15' TALL, LIGHTING ALLOWANCE	15,000.00 SF	-	-	165,000	172	63.63 /MH	10,971	175,971
			LIGHTING ACCESSORY (FIXTURE)					**187,275**	**196**		**12,452**	**199,727**
		41.99.00	**ELECTRICAL EQUIPMENT, MISCELLANEOUS**									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS -	ADD BAY TO EXISTING INTAKE STRUCTURE FOR 3RD PUMP	1.00 LT	-	-	100,000	230	82.05 /MH	18,862	118,862
			ELECTRICAL EQUIPMENT, MISCELLANEOUS					**100,000**	**230**		**18,862**	**118,862**
			ELECTRICAL EQUIPMENT					**287,275**	**426**		**31,314**	**318,589**
	71.00.00		**PROJECT INDIRECT**									
		71.25.00	**CONSULTANT, THIRD PARTY**									
			CONSULTANT - SUBSURFACE INVESTIGATION		1.00 LS	200,000	-			/MH		200,000
			CONSULTANT - GEOTECHNICAL		1.00 LS	150,000	-			/MH		150,000
			CONSULTANT, THIRD PARTY			**350,000**						**350,000**
			PROJECT INDIRECT			**350,000**						**350,000**
			121 CIVIL BOP			**570,000**		**8,073,474**	**106,878**		**11,535,049**	**20,178,523**
151			**MECHANICAL BOP**									
	11.00.00		**DEMOLITION**									
		11.21.00	**CIVIL WORK**									
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	BYPRODUCT PIPE FROM RACK	100.00 LF	-	-		172	79.31 /MH	13,674	13,674
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	REAGENT UNLOADING PIPE FROM RACK	200.00 LF	-	-		345	79.31 /MH	27,348	27,348
			CIVIL WORK						**517**		**41,022**	**41,022**
			DEMOLITION						**517**		**41,022**	**41,022**
	21.00.00		**CIVIL WORK**									
		21.17.00	**EXCAVATION**									
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,430.00 LF	-	-	8,680	526	79.31 /MH	41,715	50,395
			EXCAVATION - 6" PIPE 4' DEEP PIPE TRENCH & BEDDING		750.00 LF	-	-	4,553	276	79.31 /MH	21,879	26,431
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		3,000.00 LF	-	-	12,750	966	79.31 /MH	76,575	89,325
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		1,000.00 LF	-	-	4,250	322	79.31 /MH	25,525	29,775
			EXCAVATION - 3" PIPE 4' DEEP PIPE TRENCH & BEDDING		5,260.00 LF	-	-	22,355	1,693	79.31 /MH	134,262	156,617
			EXCAVATION - 8" PIPE 4' DEEP PIPE TRENCH & BEDDING		[illegible]340.00 LF	-	-	9,929	539	79.31 /MH	42,754	52,684

ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
CONCEPTUAL COST ESTIMATE

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	**EXCAVATION**									
			EXCAVATION - 36" PIPE 4' DEEP PIPE TRENCH & BEDDING	RIVER WATER PIPE TIE IN	20.00 LF	-	-	733	21	79.31 /MH	1,677	2,411
			EXCAVATION - 32" PIPE 4' DEEP PIPE TRENCH & BEDDING	LPSW PIPE	2,100.00 LS	-	-	60,375	1,859	79.31 /MH	147,407	207,782
			EXCAVATION - 10" PIPE 4' DEEP PIPE TRENCH & BEDDING	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	15,930	786	79.31 /MH	62,354	78,284
			EXCAVATION - 4" PIPE 4' DEEP PIPE TRENCH & BEDDING	LEACHATE PIPING	3,500.00 LF	-	-	16,905	1,167	79.31 /MH	92,528	109,433
			EXCAVATION					**156,460**	**8,154**		**646,677**	**803,138**
		21.54.00	**CAISSON**									
			2.5 FT DIA X 30 FT DEEP CAISSON	TANK FOUNDATIONS	76.00 EA	-	-	141,132	1,922	108.46 /MH	208,443	349,575
			2.5 FT DIA X 30 FT DEEP CAISSON	COMMON PIPE RACK FOUNDATIONS	186.00 EA	-	-	345,402	4,703	108.46 /MH	510,136	855,538
			2.5 FT DIA X 30 FT DEEP CAISSON	BYPRODUCT PIPE RACK FOUNDATIONS	94.00 EA	-	-	174,558	2,377	108.46 /MH	257,811	432,369
			2.5 FT DIA X 30 FT DEEP CAISSON	REAGENT UNLOADING PIPE RACK FOUNDATIONS	16.00 EA	-	-	29,712	405	108.46 /MH	43,883	73,595
			CAISSON					**690,804**	**9,407**		**1,020,272**	**1,711,076**
			CIVIL WORK					**847,264**	**17,561**		**1,666,949**	**2,514,214**
	22.00.00		**CONCRETE**									
		22.13.00	**CONCRETE**									
			SPREAD FOOTING FOUNDATION, 4500 PSI - COMPOSITE RATE	3X 35' DIA TANK FDN	81.00 CY	-	-	18,630	652	59.71 /MH	38,914	57,544
			CONCRETE FOUNDATIONS - COMPOSITE RATE	COMMON PIPE RACK FOUNDATIONS	207.00 CY	-	-	47,610	1,666	59.71 /MH	99,448	147,058
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BYPRODUCT PIPE RACK FOUNDATIONS	105.00 CY	-	-	24,150	845	59.71 /MH	50,445	74,595
			CONCRETE FOUNDATIONS - COMPOSITE RATE	REAGENT UNLOADING PIPE RACK FOUNDATIONS	18.00 CY	-	-	4,140	145	59.71 /MH	8,648	12,788
			CONCRETE					**94,530**	**3,307**		**197,455**	**291,985**
			CONCRETE					**94,530**	**3,307**		**197,455**	**291,985**
	23.00.00		**STEEL**									
		23.21.00	**GIRDER**									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	COMMON 500'LX20'W, 400'Lx15'W,400'Lx9'W, ALL 20' HIGH	196.00 TN	-	-	531,160	3,830	92.62 /MH	354,724	885,884
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	BYPRODUCT PIPE RACK, 650LF X6 WIDE X 20' HIGH	39.00 TN	-	-	105,690	762	92.62 /MH	70,583	176,273
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	REAGENT UNLOADING PIPE RACK, 100LF X 6' WIDE X 20' HIGH	6.00 TN	-	-	16,260	117	92.62 /MH	10,859	27,119
			GIRDER					**653,110**	**4,709**		**436,166**	**1,089,276**
			STEEL					**653,110**	**4,709**		**436,166**	**1,089,276**
	27.00.00		**PAINTING & COATING**									
		27.13.00	**COATING**									
			COATING - CHIMNEY - ACID RESISTANT COATING TOP 100 FT OUTSIDE SHELL		1.00 LS	270,000	-			47.61 /MH		270,000
			COATING			**270,000**						**270,000**
			PAINTING & COATING			**270,000**						**270,000**
	31.00.00		**MECHANICAL EQUIPMENT**									
		31.17.00	**COMPRESSOR & ACCESSORIES**									
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	SERVICE AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR COMPRESSOR, CENTRIFUGAL - 250 SCFM EA @ 200 PSIG	INSTRUMENT AIR	2.00 EA	-	310,000	-	92	68.48 /MH	6,297	316,297
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	SERVICE AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR DRYER - W/FILTERS, 250 NET SCFM EA	INSTRUMENT AIR	2.00 EA	-	33,400	-	74	68.48 /MH	5,038	38,438
			AIR RECEIVER - 1,000 GALLON EA	SERVICE AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			AIR RECEIVER - 1,000 GALLON EA	INSTRUMENT AIR	2.00 EA	-	11,200	-	37	68.48 /MH	2,519	13,719
			COMPRESSOR & ACCESSORIES				**709,200**		**405**		**27,707**	**736,907**
		31.41.00	**FIRE PROTECTION EQUIPMENT & SYSTEM**									
			DELUGE - POWER TRANSFORMERS		3.00 EA	-	-	127,500	1,959	77.36 /MH	151,519	279,019
			FIRE PROTECTION EQUIPMENT & SYSTEM					**127,500**	**1,959**		**151,519**	**279,019**
		31.65.00	**HEAT EXCHANGER**									
			HEAT EXCHANGER - SLAKER WATER HEATER 3" IN-LINE, 475 KW		4.00 EA	-	220,000	-	368	63.63 /MH	23,404	243,404
			HEAT EXCHANGER				**220,000**		**368**		**23,404**	**243,404**

Exhibit B to EAI Comments

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.75.00	**PUMP**									
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - MAKEUP WATER PUMPS, 2600 GPM, 200 TDH		2.00 EA	-	96,000	-	577	68.48 /MH	39,514	135,514
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - RECYCLE ASH WATER PUMP, 50 HP		3.00 EA	-	72,000	-	221	68.48 /MH	15,113	87,113
			CENTRIFUGAL, HORIZONTAL, SINGLE STAGE - LIME SLAKING WATER PIUMPS, 50 HP		2.00 EA	-	48,000	-	147	68.48 /MH	10,075	58,075
			CENTRIFUGAL, VERTICAL, CANNED - LEACHATE PUMPS, 50 HP		2.00 EA	-	134,000	-	828	68.48 /MH	56,673	190,673
			CENTRIFUGAL, VERTICAL, WET PIT - LPSW PUMP, 650 HP		1.00 EA	-	188,000	-	690	68.48 /MH	47,228	235,228
			SUMP, CENTRIFUGAL, WET BEARING - REGENT PREP/RECYCLE SUMP, 120GPM, 150 TDH		4.00 EA	-	220,000	-	276	68.48 /MH	18,891	238,891
			SUMP, CENTRIFUGAL, WET BEARING - LIME SILO & UNLOADING AREA SUMP 120 GPM @ 150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTE ASH SILO AREA SUMP 120GPM @150 TDH		2.00 EA	-	88,000	-	138	68.48 /MH	9,446	97,446
			SUMP, CENTRIFUGAL, WET BEARING - WASTEWATER FORWARDING PUMP TO RECYCLED SLURRY, 100 GPM@150 TDH		4.00 EA	-	28,800	-	294	68.48 /MH	20,150	48,950
			SUMP, SUBMERSIBLE - RECYCLE ASH WATER TANK SUPPLY PUMP, 100 HP		2.00 EA	-	77,000	-	690	68.48 /MH	47,228	124,228
			PUMP				**1,039,800**		**3,998**		**273,763**	**1,313,563**
		31.83.00	**TANK**									
			ATMOSPHERIC, FIELD FABRICATED - LIME SLAKING WATER TANK, 175,000 GALLON	35' DIA X 24' HIGH	1.00 EA	220,000		-		90.81 /MH		220,000
			ATMOSPHERIC, FIELD FABRICATED - RECYCLE ASH WATER TANK, 250,000 GALLON	35' DIA X 36' HIGH	2.00 EA	508,000		-		90.81 /MH		508,000
			TANK			**728,000**						**728,000**
			MECHANICAL EQUIPMENT			**728,000**	**1,969,000**	**127,500**	**6,729**		**476,392**	**3,300,892**
	35.00.00		**PIPING**									
		35.13.01	**SS 304, ABOVE GROUND, PROCESS AREA**									
			1 IN DIA, SCH 40S		1,520.00 LF	-	-	32,832	1,974	77.36 /MH	152,728	185,560
			1.5 IN DIA, SCH 40S		1,380.00 LF	-	-	52,302	2,094	77.36 /MH	161,976	214,278
			2 IN DIA, SCH 40S		2,070.00 LF	-	-	113,022	3,426	77.36 /MH	265,051	378,073
			SS 304, ABOVE GROUND, PROCESS AREA					**198,156**	**7,494**		**579,755**	**777,911**
		35.13.10	**CARBON STEEL, ABOVE GROUND, PROCESS AREA**									
			1 IN DIA, SCH 80		260.00 LF	-	-	2,314	305	77.36 /MH	23,581	25,895
			2 IN DIA, SCH 80		2,260.00 LF	-	-	48,138	3,273	77.36 /MH	253,207	301,345
			2.5 IN DIA, SCH 40		1,000.00 LF	-	-	15,400	1,437	77.36 /MH	111,149	126,549
			3 IN DIA, SCH 40		7,160.00 LF	-	-	125,300	11,028	77.36 /MH	853,130	978,430
			3 IN DIA, SCH 80		1,760.00 LF	-	-	38,720	3,055	77.36 /MH	236,313	275,033
			4 IN DIA, SCH 40		1,000.00 LF	-	-	22,600	1,701	77.36 /MH	131,601	154,201
			6 IN DIA, SCH 40		880.00 LF	-	-	28,248	1,629	77.36 /MH	125,981	154,229
			6 IN DIA, SCH 40 VACUUM PIPE		2,260.00 LF	-	-	72,546	4,182	77.36 /MH	323,543	396,089
			8 IN DIA, SCH 80		3,520.00 LF	-	-	256,608	9,832	77.36 /MH	760,582	1,017,190
			CARBON STEEL, ABOVE GROUND, PROCESS AREA					**609,874**	**36,441**		**2,819,087**	**3,428,961**
		35.13.36	**DUCTILE IRON, ABOVE GROUND, PROCESS AREA**									
			12 IN DIA, - ASHCOLITE PIPE		1,620.00 LF	-	-	162,000	3,594	72.14 /MH	259,256	421,256
			DUCTILE IRON, ABOVE GROUND, PROCESS AREA					**162,000**	**3,594**		**259,256**	**421,256**
		35.14.10	**CARBON STEEL, STRAIGHT RUN**									
			6 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	1,200.00 LF	-	-	27,480	1,214	77.36 /MH	93,899	121,379
			8 IN DIA, SCH 40, LIME SLAKING TANK MAKEUP	LIME SLAKING TANK MAKEUP	450.00 LF	-	-	13,905	486	77.36 /MH	37,613	51,518
			8 IN DIA, SCH 40, RECYCLE ASH WATER PIPING	RECYCLE ASH WATER PIPING	2,000.00 LF	-	-	61,800	2,161	77.36 /MH	167,169	228,969
			10 IN DIA, SCH 40, RECYCLE ASH TANK MAKEUP	RECYCLE ASH TANK MAKEUP	450.00 LF	-	-	24,660	610	77.36 /MH	47,216	71,876
			CARBON STEEL, STRAIGHT RUN					**127,845**	**4,471**		**345,897**	**473,742**
		35.15.10	**CARBON STEEL, BURIED**									
			3 IN DIA, SCH 40, WRAPPED		3,000.00 LF	-	-	51,000	2,241	77.36 /MH	173,393	224,393
			4 IN DIA, SCH 40, WRAPPED, LEACHATE PIPING	LEACHATE PIPING	3,500.00 LF	-	-	72,800	2,856	77.36 /MH	220,965	293,765
			6 IN DIA, SCH 40, WRAPPED		750.00 LF	-	-	23,925	776	77.36 /MH	60,021	83,946
			10 IN DIA, SCH 40, WRAPPED, RECYCLE ASH WATER PIPE DISCHARGE BURIED	RECYCLE ASH WATER PIPE DISCHARGE BURIED	1,800.00 LF	-	-	119,700	2,441	77.36 /MH	188,865	308,565

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		35.15.10	CARBON STEEL, BURIED									
			32 IN DIA, 3/8 IN STD, WRAPPED - LPSW PIPE	LPSW PIPE	2,100.00 LF	-	-	638,610	11,079	77.36 /MH	857,095	1,495,705
			36 IN DIA, 3/8 IN STD, WRAPPED - RIVER WATER PIPE	RIVER WATER PIPE - TIE IN	20.00 LF	-	-	6,772	138	77.36 /MH	10,706	17,478
			CARBON STEEL, BURIED					912,807	19,533		1,511,045	2,423,852
		35.15.25	FRP, BURIED									
			3 IN DIA, TAPER		1,000.00 LF	-	-	14,800	460	77.36 /MH	35,568	50,368
			3 IN DIA, TAPER FRP/HDPE PIPE		2,380.00 LF	-	-	35,224	1,094	77.36 /MH	84,651	119,875
			FRP, BURIED					50,024	1,554		120,219	170,243
		35.15.30	HDPE, BURIED									
			6 IN DIA, DR 9		1,430.00 LF	-	-	12,870	1,134	77.36 /MH	87,737	100,607
			8 IN DIA, DR 9		1,340.00 LF	-	-	20,770	1,278	77.36 /MH	98,896	119,666
			HDPE, BURIED					33,640	2,413		186,633	220,273
		35.36.00	PIPE SUPPORTS, RACK									
			SUPPORT SLEEPERS	BYPRODUCT PIPE, 1750LF	125.00 EA	-	-	43,750	575	77.36 /MH	44,460	88,210
			SUPPORT SLEEPERS	REAGENT UNLOADING PIPE, 1500LF	108.00 EA	-	-	37,800	497	77.36 /MH	38,413	76,213
			PIPE SUPPORTS, RACK					81,550	1,071		82,873	164,423
		35.45.00	VALVES									
			VALVE - 36" 150 LB CS BUTTERFLY, FLANGED		2.00 EA	-	-	79,920	96	77.36 /MH	7,398	87,318
			VALVE - 12" 150 LB CS KNIFE GATE, FLANGED		6.00 EA	-	-	20,160	195	77.36 /MH	15,099	35,259
			VALVE - 12" 150 LB CS GATE VALVE, FLANGED		2.00 EA	-	-	8,920	65	77.36 /MH	5,033	13,953
			VALVE - 10" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	9,200	55	77.36 /MH	4,268	13,468
			VALVE - 10" 150 LB CS BUTTERFLY, FLANGED		5.00 EA	-	-	22,200	138	77.36 /MH	10,670	32,870
			VALVE - 8" 150 LB CS GATE, FLANGED		20.00 EA	-	-	100,000	425	77.36 /MH	32,900	132,900
			VALVE - 6" 150 LB CS GATE, FLANGED		6.00 EA	-	-	19,800	110	77.36 /MH	8,536	28,336
			VALVE - 6" 150 LB CS AIR OPERATED GATE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS AIR OPERATED GLOBE, FLANGED		4.00 EA	-	-	20,400	74	77.36 /MH	5,691	26,091
			VALVE - 6" 150 LB CS SWING CHECK, FLANGED		2.00 EA	-	-	3,400	37	77.36 /MH	2,845	6,245
			VALVE - 4" 150 LB CS GATE, FLANGED		3.00 EA	-	-	3,825	25	77.36 /MH	1,921	5,746
			VALVE - 3" AND BELOW CS FOR SERVICE WATER ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" AND BELOW CS FOR SERVICE AIR ISOLATION		120.00 EA	-	-	1,224,000	1,076	77.36 /MH	83,229	1,307,229
			VALVE - 3" 150 LB CS GATE, FLANGED		20.00 EA	-	-	15,000	179	77.36 /MH	13,871	28,871
			VALVE - 3" CS PST IND FOR FP 250 LB		6.00 EA	-	-	6,600	54	77.36 /MH	4,161	10,761
			VALVE - 2" AND ABOVE BRONZE VALVES FOR INSTRUMENT AIR ISOLATION		600.00 EA	-	-	78,000	501	77.36 /MH	38,787	116,787
			VALVE - 1" CS FLANGED		4.00 EA	-	-	880	21	77.36 /MH	1,636	2,516
			VALVE - 6" CI POST INDICATOR 250 LB., MECHANICAL JOINT WITH BOXES BURIED VALVE		6.00 EA	-	-	4,080	28	77.36 /MH	2,134	6,214
			VALVES					2,860,785	4,228		327,099	3,187,884
			PIPING					5,036,681	80,799		6,231,866	11,268,547
	36.00.00		INSULATION									
		36.17.01	PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING									
			CALCIUM SILICATE W/ALUMINUM JACKETING - 8" PIPE 1.5" THICK		2,520.00 LF	-	-	16,380	487	68.76 /MH	33,460	49,840
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		1,260.00 LF	-	-	3,591	155	68.76 /MH	10,655	14,246
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 3" PIPE		5,660.00 LF	-	-	16,131	696	68.76 /MH	47,865	63,996
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.5" PIPE		380.00 LS	-	-	1,083	47	68.76 /MH	3,214	4,297
			1" CALCIUM SILICATE W/ALUMINUM JACKETING - 2.0" PIPE		4,140.00 LS	-	-	10,309	476	68.76 /MH	32,720	43,029
			PIPE, CALCIUM SILICATE W/ALUMINUM JACKETING					47,494	1,860		127,914	175,408
			INSULATION					47,494	1,860		127,914	175,408
	41.00.00		ELECTRICAL EQUIPMENT									
		41.33.00	HEAT TRACING									
			HEAT TRACING - 8" PIPE		2,520.00 LS	-	-	18,749	43	63.63 /MH	2,765	21,513
			HEAT TRACING - 3" PIPE		1,260.00 LF	-	-	9,374	22	63.63 /MH	1,382	10,757
			HEAT TRACING - 3" PIPE		5,660.00 LF	-	-	42,110	98	63.63 /MH	6,209	48,320
			HEAT TRACING - 2.5" PIPE		380.00 LS	-	-	2,827	7	63.63 /MH	417	3,244
			HEAT TRACING - 2.0" PIPE		440.00 LS	-	-	3,274	8	63.63 /MH	483	3,756
			HEAT TRACING					76,334	177		11,256	87,590
			ELECTRICAL EQUIPMENT					76,334	177		11,256	87,590

Exhibit B to EAI Comments

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			151 MECHANICAL BOP			**998,000**	**1,969,000**	**6,882,913**	**115,659**		**9,189,021**	**19,038,934**
190			**DEMOLITION / RELOCATION**									
	11.00.00		**DEMOLITION**									
		11.21.00	**CIVIL WORK**									
			CIVIL WORK - REMOVE FENCING & GATES	HAZARDOUS MATERIAL ACCUMULATION BLDG	1,133.00 LF	-	-		91	107.10 /MH	9,763	9,763
			CIVIL WORK - DIG AND REFILL PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		948	79.31 /MH	75,208	75,208
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH E970 FROM N2055 'TO N1350'	705.00 LF	-	-		1,216	79.31 /MH	96,403	96,403
			CIVIL WORK - REMOVE DRAINAGE DITCH	DRAINAGE DITCH e1350 from n970' to n1180'	210.00 LF	-	-		362	79.31 /MH	28,716	28,716
			CIVIL WORK - DEMO AREA PAVEMENT	ASH HANDLING / ELECT BLDG	1.00 LS	-	-		115	107.10 /MH	12,310	12,310
			CIVIL WORK						**2,732**		**222,400**	**222,400**
		11.22.00	**CONCRETE**									
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	80.00 CY	-	-		230	107.10 /MH	24,621	24,621
			CONCRETE FOUNDATION - HAZARDOUS MATERIAL ACCUMULATION BLDG	HAZARDOUS MATERIAL ACCUMULATION BLDG, HAZMAT PAVEMENT DEMO	12.00 CY	-	-		61	107.10 /MH	6,574	6,574
			CONCRETE FOUNDATION - ASH HANDLING MAINT BLDG	ASH HANDLING / ELECT BLDG FDN	225.00 CY	-	-		647	107.10 /MH	69,246	69,246
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	FLOURESCENT LIGHT TUBE DISPOSAL SHED FDN	2.00 CY	-	-		10	107.10 /MH	1,096	1,096
			CONCRETE FOUNDATION - PAVING & FOUNDATION DEMO	USED OIL SHED DEMO	35.00 CY	-	-		101	107.10 /MH	10,772	10,772
			CONCRETE						**1,049**		**112,307**	**112,307**
		11.23.00	**STEEL**									
			STRUCTURAL STEEL DISASSEMBLE BLDG STEEL & TOOL CRIB FOR RELOCATION	ASH HANDLING / ELECT BLDG	52.00 TN	-	-		359	107.10 /MH	38,408	38,408
			STEEL						**359**		**38,408**	**38,408**
		11.24.00	**ARCHITECTURAL**									
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, 50'X50'X20'	50,000.00 CF	-	-		632	107.10 /MH	67,707	67,707
			ARCHITECTURAL - HAZARDOUS MATERIAL ACCUMULATION BLDG 50'X50'X20'	HAZARDOUS MATERIAL ACCUMULATION BLDG, CONTAINER DISPOSAL AREA	1.00 LT	-	-		287	107.10 /MH	30,776	30,776
			ARCHITECTURAL - DEMO EXISTING INSULATED SIDING & ROOFING , DEMO INTERIOR OFFICES	ASH HANDLING / ELECT BLDG	15,000.00 CF	-	-		862	107.10 /MH	92,328	92,328
			ARCHITECTURAL - BLDG DEMO	COAL DUMPER AIR COMPRESSOR DEMOLITION	100.00 SF	-	-		11	107.10 /MH	1,231	1,231
			ARCHITECTURAL - BLDG DEMO	USED OIL SHED DEMO	600.00 SF	-	-		8	107.10 /MH	812	812
			ARCHITECTURAL						**1,801**		**192,854**	**192,854**
		11.31.00	**MECHANICAL EQUIPMENT**									
			MECHANICAL EQUIPMENT - DEMOLISH SEPTIC TANKS	ASH HANDLING / ELECT BLDG	2.00 EA	-	-		0	107.10 /MH	25	25
			MECHANICAL EQUIPMENT - REMOVE 15 TN BRIDGE CRANE (50 FT SPAN) , CRANE SUPPORT STEEL AND 3 JIB CRANES FGOR RELOCATION	ASH HANDLING / ELECT BLDG	21.00 TN	-	-		290	92.62 /MH	26,828	26,828
			MECHANICAL EQUIPMENT						**290**		**26,852**	**26,852**
		11.35.00	**PIPING**									
			PIPING - REMOVE 12" BA PIPE IN PIPE TRENCH	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		87	107.10 /MH	9,276	9,276
			PIPING - REMOVE 10" FA PIPE	TRENCH N.1784.33 FROM E905' TO 1180'	550.00 LF	-	-		76	107.10 /MH	8,125	8,125
			PIPING						**162**		**17,401**	**17,401**
		11.99.00	**DEMOLITION, MISCELLANEOUS**									
			DEMOLITION - MISC	ALLOWANCE	1.00 LT	-	-		2,299	92.62 /MH	212,920	212,920
			DEMOLITION, MISCELLANEOUS						**2,299**		**212,920**	**212,920**
			DEMOLITION						**8,691**		**823,142**	**823,142**
	21.00.00		**CIVIL WORK**									
		21.16.00	**GENERAL EARTHWORK**									
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	HAZARDOUS MATERIAL ACCUMULATION BLDG	300.00 CY	-	-	4,800	138	182.33 /MH	25,149	29,949
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE	ASH HANDLING / ELECT BLDG	1,000.00 CY	-	-	16,000	460	182.33 /MH	83,830	99,830
			EARTHWORK - COVER AREA WITH BACKFILL AND GRADE 250'X250'X2'	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	5,000.00 CY	-	-	80,000	259	182.33 /MH	47,154	127,154
			GENERAL EARTHWORK					**100,800**	**856**		**156,133**	**256,933**

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		21.17.00	EXCAVATION									
			EXCAVATION - ALLOWANCE FOR NEW DITCHES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	1,200.00 CY	-	-		276	79.31 /MH	21,879	21,879
			EXCAVATION						276		21,879	21,879
		21.20.00	BACKFILL									
			FOUNDATION BACKFILL, PREVIOUSLY EXCAVATED MATERIAL, ALLOWANCE FOR OLD DITCHES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	100.00 CY	-	-		17	79.31 /MH	1,367	1,367
			BACKFILL						17		1,367	1,367
		21.21.00	MASS FILL									
			MASS FILL, COMMON EARTH USING DUMP TRUCK, 2 MI ROUND TRIP, ALLWANCE FOR MISC ADDITIONAL FILL	RELOCATED BLDGS	1.00 LT	-	-	30,000	345	79.31 /MH	27,348	57,348
			MASS FILL					30,000	345		27,348	57,348
		21.39.00	STORM DRAINAGE UTILITIES									
			EXTEND CULVERTS UNDER ROAD	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG) AREA FILL	48.00 LF	-	-	4,800	166	79.31 /MH	13,127	17,927
			STORM DRAINAGE UTILITIES					4,800	166		13,127	17,927
		21.41.00	EROSION AND SEDIMENTATION CONTROL									
			EROSION AND SEDIMENTATION CONTROL - ALLOWANCE	RELOCATED BLDGS	1.00 LS	-	-	20,000	345	36.12 /MH	12,455	32,455
			EROSION AND SEDIMENTATION CONTROL					20,000	345		12,455	32,455
		21.43.00	FENCEWORK									
			FABRIC, WIRE & POSTS, CHAIN LINK FENCE, GALVANIZED, 6 FT TALL, 6 GAGE 3 STRANDS OF BARB WIRE, 2 IN POST AT 10 FT O.C.	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	800.00 FT	-	-	18,880	92	36.12 /MH	3,321	22,201
			VEHICLE GATE, 14 FT WIDE BY 7 FT TALL	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	4.00 EA	-	-	4,000	110	36.12 /MH	3,986	7,986
			FENCEWORK					22,880	202		7,307	30,187
		21.47.00	LANDSCAPING									
			LANDSCAPING - ALLOWANCE FOR PAVING GRADING & SEEDING	RELOCATED BLDGS	1.00 LS	-	-	40,000	460	36.12 /MH	16,607	56,607
			LANDSCAPING					40,000	460		16,607	56,607
		21.57.00	ROAD, PARKING AREA, & SURFACED AREA									
			BITUMINOUS ASPHALT (10,000 - 49,999 SF) ASHPALT PAVING FOR TRUCK TURNAROUND , DRIVEWAY AND AROUND BLDG	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	43,000.00 SF	-	-	216,720	1,236	78.37 /MH	96,836	313,556
			ROAD, PARKING AREA, & SURFACED AREA					216,720	1,236		96,836	313,556
			CIVIL WORK					435,200	3,902		353,060	788,260
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	320.00 CY	-	-	73,600	2,575	59.71 /MH	153,736	227,336
			SLAB FOUNDATION LESS THAN 2 FT THICK, 4500 PSI, - COMPOSITE RATE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)- CONTAINER DISPOSAL SLAB & APRON	550.00 CY	-	-	126,500	4,425	59.71 /MH	264,234	390,734
			CONCRETE FOUNDATIONS - COMPOSITE RATE	ACI PORT STAIRTOWER FDNS	60.00 CY	-	-	13,800	483	59.71 /MH	28,826	42,626
			CONCRETE					213,900	7,483		446,796	660,696
			CONCRETE					213,900	7,483		446,796	660,696
	23.00.00		STEEL									
		23.17.00	GALLERY									
			GALVANIZED GRATING, 1 1/4" DEEP x 3/16" BEARING BAR WITH HOLD DOWN CLIPS	ACI PORT STAIR TOWERS AND PLATFORMS	728.00 SF	-	-	10,920	84	66.07 /MH	5,529	16,449
			DOUBLE PIPE HANDRAIL WITH POSTS AND GUARD PLATES, PAINTED	ACI PORT STAIR TOWERS AND PLATFORMS	436.00 LF	-	-	23,108	90	66.07 /MH	5,960	29,068
			STAIR SYSTEM	ACI PORT STAIR TOWERS AND PLATFORMS	896.00 SF	-	-	81,536	1,184	66.07 /MH	78,251	159,787
			GALLERY					115,564	1,358		89,740	205,304
		23.21.00	GIRDER									

Exhibit B to EAI Comments

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.21.00	GIRDER									
			ROLLED SHAPE GIRDER - MEDIUM WEIGHT MEMBER 20# TO 40# / LF, 2 COAT PAINTED	UNIT 2 ACI PIPE RACK OVER ROADWAY, 35LF X 23 WIDE X 20' HIGH	1.26 TN	-	-	3,415	25	92.62 /MH	2,280	5,695
			GIRDER					3,415	25		2,280	5,695
		23.25.00	ROLLED SHAPE									
			LIGHT WEIGHT MEMBERS, LESS THAN 20 LB/LF, TWO COAT PAINT	ACI PORT STAIRTOWER FRAMING - 2 TOWERS	4.40 TN	-	-	15,752	111	92.62 /MH	10,305	26,057
			REASSEMBLE ASH HANDLING/ELEC BLDG METAL FRAME, PURLINS & GIRTS AS NEW LABOR SHOP	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	50.00 TN	-	-		1,379	92.62 /MH	127,752	127,752
			ROLLED SHAPE					15,752	1,491		138,057	153,809
			STEEL					134,731	2,873		230,077	364,808
	24.00.00		ARCHITECTURAL									
		24.15.00	DOOR (INCL. FRAME & HARDWARE)									
			DOOR (INCL. FRAME & HARDWARE) - ROLL UP DOOR MAN DOOR ETC...	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			DOOR (INCL. FRAME & HARDWARE)					5,000	92		4,699	9,699
		24.27.00	MASONRY									
			BLOCK, CONCRETE, 8 IN, HOLLOW REINFORCED, ALTERNATE COURSES	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	850.00 SF	-	-	4,242	106	53.08 /MH	5,601	9,842
			MASONRY					4,242	106		5,601	9,842
		24.35.00	PRE-ENGINEERED BUILDING									
			SHELL ONLY, STEEL UNINSULATED 22 GA,	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	140,000	1,954	92.62 /MH	180,982	320,982
			PRE-ENGINEERED BUILDING					140,000	1,954		180,982	320,982
		24.37.00	ROOFING									
			METAL, INSULATED- NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	50,505	2,241	35.02 /MH	78,493	128,998
			ROOFING					50,505	2,241		78,493	128,998
		24.41.00	SIDING									
			METAL, INSULATED, NEW INSULATED SIDING & ROOFING	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	8,500.00 SF	-	-	140,760	870	79.59 /MH	69,207	209,967
			SIDING					140,760	870		69,207	209,967
		24.99.00	ARCHITECTURAL, MISCELLANEOUS									
			ARCHITECTURAL, MISCELLANEOUS - OFFICE ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LS	-	-	100,000	2,299	51.10 /MH	117,471	217,471
			ARCHITECTURAL, MISCELLANEOUS - TOOL CRIB	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	1.00 LS	-	-	5,000	92	51.10 /MH	4,699	9,699
			ARCHITECTURAL, MISCELLANEOUS					105,000	2,391		122,170	227,170
			ARCHITECTURAL					445,507	7,653		461,151	906,658
	27.00.00		PAINTING & COATING									
		27.17.00	PAINTING									
			PAINTING - ALLOWANCE	NEW ASH HANDLING MAINT BLDG 45'X45'X18' TALL	2,025.00 SF	-	-	2,025	23	47.61 /MH	1,108	3,133
			PAINTING					2,025	23		1,108	3,133
			PAINTING & COATING					2,025	23		1,108	3,133
	31.00.00		MECHANICAL EQUIPMENT									
		31.25.00	CRANES & HOISTS									
			BRIDGE CRANE - INSTALL SALVAGED 15 TN BRIDGE CRANE AND 2 JIB CRANES WITH EXISTING SUPPORT STEEL	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	21.00 TN	-	-	-	290	92.62 /MH	26,828	26,828
			BRIDGE CRANE - LOAD TEST & CERTIFY BRIDGE CRANE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 EA	-	-	-	230	92.62 /MH	21,292	21,292
			MOTORIZED HOIST - 1 TON	RELOCATED FROM PRESENT PORT LOCATIOIN	2.00 EA	-	-	-	138	68.48 /MH	9,446	9,446
			CRANES & HOISTS						657		57,565	57,565
		31.41.00	FIRE PROTECTION EQUIPMENT & SYSTEM									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		31.41.00	**FIRE PROTECTION EQUIPMENT & SYSTEM**									
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	1.00 LT	-	-	10,000	138	68.48 /MH	9,446	19,446
			FIRE PROTECTION EQUIPMENT & SYSTEM - USER DEFINED	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	27,500	385	68.48 /MH	26,369	53,869
			FIRE PROTECTION EQUIPMENT & SYSTEM					**37,500**	**523**		**35,814**	**73,314**
		31.51.00	**MERCURY REMOVAL EQUIPMENT**									
			ACTIVATED CARBON INJECTION (ACI) - LANCE RELOCATIONS	RELOCATED FROM PRESENT PORT LOCATIOIN (16 PER UNIT)	32.00 EA	-	-	-	368	68.48 /MH	25,188	25,188
			ACTIVATED CARBON INJECTION (ACI) - 40 HP BLOWERS	NEW BLOWERS (2 PER UNIT)	4.00 EA	-	-	80,000	184	68.48 /MH	12,594	92,594
			ACTIVATED CARBON INJECTION (ACI) - REMOVE EXISTING 20 HP BLOWERS	REMOVE EXISTING	2.00 EA	-	-	-	23	68.48 /MH	1,574	1,574
			MERCURY REMOVAL EQUIPMENT					**80,000**	**575**		**39,356**	**119,356**
			MECHANICAL EQUIPMENT					**117,500**	**1,755**		**132,736**	**250,236**
	34.00.00		**HVAC**									
		34.99.00	**HVAC, MISCELLANEOUS**									
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS - HVAC ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	2,100.00 SF	-	-	23,100	24	64.10 /MH	1,547	24,647
			HVAC, MISCELLANEOUS					**46,200**	**48**		**3,094**	**49,294**
			HVAC					**46,200**	**48**		**3,094**	**49,294**
	35.00.00		**PIPING**									
		35.13.25	**FRP, ABOVE GROUND, PROCESS AREA**									
			1.5 IN DIA, TAPER	INJECTION PORTS	12.00 LF	-	-	353	6	77.36 /MH	437	790
			2 IN DIA, TAPER	INJECTION PORTS	16.00 LF	-	-	421	9	77.36 /MH	697	1,118
			3 IN DIA, TAPER	INJECTION PORTS	40.00 LF	-	-	1,032	31	77.36 /MH	2,383	3,415
			FRP, ABOVE GROUND, PROCESS AREA					**1,806**	**45**		**3,518**	**5,323**
		35.14.25	**FRP, STRAIGHT RUN**									
			4 IN DIA, TAPER	NEW ACI PIPING	600.00 LF	-	-	12,660	400	77.36 /MH	30,944	43,604
			FRP, STRAIGHT RUN					**12,660**	**400**		**30,944**	**43,604**
		35.36.00	**PIPE SUPPORTS, RACK**									
			U-BOLT FOR 4 IN PIPE	ACI PIPE	27.00 EA	-	-	81	62	77.36 /MH	4,802	4,883
			SUPPORT SLEEPERS	ACI PIPE 330 LF	17.00 EA	-	-	5,950	78	77.36 /MH	6,047	11,997
			SUPPORT FOR 4 IN DIA PIPE - USER DEFINED		2.00 EA	-	-	306	18	77.36 /MH	1,423	1,729
			SUPPORT FOR 3 IN DIA PIPE - USER DEFINED		4.00 EA	-	-	576	32	77.36 /MH	2,490	3,066
			PIPE SUPPORTS, RACK					**6,913**	**191**		**14,761**	**21,674**
		35.45.00	**VALVES**									
			VALVE - 4" 150 LB CS GATE, FLANGED	ACI AUTO MATIC ISOLATION VALVES (RELOCATE 4 PER UNIT)	8.00 EA	-	-	160	66	77.36 /MH	5,122	5,282
			VALVES					**160**	**66**		**5,122**	**5,282**
			PIPING					**21,539**	**702**		**54,344**	**75,883**
	41.00.00		**ELECTRICAL EQUIPMENT**									
		41.37.00	**LIGHTING ACCESSORY (FIXTURE)**									
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	NEW LABOR SHOP METAL BLDG (WAS ASH HANDLING / ELECTRICAL BLDG)	6,500.00 SF	-	-	71,500	75	63.63 /MH	4,754	76,254
			LIGHTING ACCESSORY (FIXTURE) - ALLOWANCE	WASTE MANAGEMENT FACILITY (REPLACES HAZMAT BLDG)	5,000.00 SF	-	-	55,000	57	63.63 /MH	3,657	58,657
			LIGHTING ACCESSORY (FIXTURE)					**126,500**	**132**		**8,411**	**134,911**
		41.46.00	**MOTOR CONTROL CENTER (MCC), COMPONENT**									
			FVN STARTER - #4,	NEW BLOWERS	3.00 EA	-	-	14,700	55	63.63 /MH	3,511	18,211
			MOTOR CONTROL CENTER (MCC), COMPONENT					**14,700**	**55**		**3,511**	**18,211**
			ELECTRICAL EQUIPMENT					**141,200**	**187**		**11,921**	**153,121**
	42.00.00		**RACEWAY, CABLE TRAY & CONDUIT**									
		42.15.23	**CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY**									
			1-1/2 IN DIA, 3 FT LONG INCLUDING (2) CONNECTORS	NEW BLOWERS	3.00 EA	-	-	258	4	61.79 /MH	266	524
			CONDUIT, FLEXIBLE SEALTIGHT ASSEMBLY					**258**	**4**		**266**	**524**

Exhibit B to EAI Comments

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.15.37	CONDUIT, RGS									
			3/4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	HOIST	450.00 LF	-	-	1,319	100	61.79 /MH	6,200	7,519
			1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	NEW BLOWERS	400.00 LF	-	-	2,688	131	61.79 /MH	8,068	10,756
			CONDUIT, RGS					4,007	231		14,269	18,275
			RACEWAY, CABLE TRAY & CONDUIT					4,264	235		14,535	18,799
	43.00.00		CABLE									
		43.10.00	CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC	ACI RELOCATION	600.00 LF	-	-	1,920	55	82.05 /MH	4,527	6,447
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					1,920	55		4,527	6,447
		43.20.00	600V CABLE & TERMINATION									
			600V #8 3/C CU EPR TS-CPE	HOIST	500.00 LF	-	-	3,280	14	82.05 /MH	1,179	4,459
			600V #4/0 3/C W/G CU EPR TS-CPE	NEW BLOWERS	450.00 LF	-	-	10,728	72	82.05 /MH	5,942	16,670
			TERMINATION - COMPRESSION LUG, #8, 2 HOLE, COPPER	HOIST	12.00 EA	-	-	78	4	82.05 /MH	340	418
			TERMINATION - COMPRESSION LUG, #4, 2 HOLE, COPPER	NEW BLOWERS	12.00 EA	-	-	111	7	82.05 /MH	566	677
			600V CABLE & TERMINATION					14,197	98		8,026	22,223
			CABLE					16,117	153		12,553	28,670
	44.00.00		CONTROL & INSTRUMENTATION									
		44.21.00	INSTRUMENT									
			ACCOUSTIC MONITOR	RELOCATE TO NEW INJECTION LANCES	6.00 EA	-	-		28	64.68 /MH	1,784	1,784
			INSTRUMENT						28		1,784	1,784
			CONTROL & INSTRUMENTATION						28		1,784	1,784
	71.00.00		PROJECT INDIRECT									
		71.25.00	CONSULTANT, THIRD PARTY									
			COMPUTATIONAL FLUID DYNAMIC ANALYSIS (CFD)	ACI SYSTEM	1.00 LS	100,000	-			/MH		100,000
			CONSULTANT, THIRD PARTY			100,000						100,000
			PROJECT INDIRECT			100,000						100,000
			190 DEMOLITION / RELOCATION			**100,000**		**1,578,182**	**33,735**		**2,546,302**	**4,224,484**
201			**ELECTRICAL BOP SYSTEM**									
	21.00.00		CIVIL WORK									
		21.54.00	CAISSON									
			2.5 FT DIA X 30 FT DEEP CAISSON	U1 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			2.5 FT DIA X 30 FT DEEP CAISSON	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	36.00 EA	-	-	66,852	910	108.46 /MH	98,736	165,588
			2.5 FT DIA X 30 FT DEEP CAISSON	BUS DUCT SUPPORTS	167.00 EA	-	-	310,119	4,223	108.46 /MH	458,025	768,144
			2.5 FT DIA X 30 FT DEEP CAISSON	OVERHEAD TRANSMISSION LINE STRUCTURAL - INCLUDES 115 KV DISCONNECT SWITCH FOUNDATION	10.00 EA	-	-	18,570	253	108.46 /MH	27,427	45,997
			2.5 FT DIA X 30 FT DEEP CAISSON	U2 MAIN ELECT BLDG 40'X100'	23.00 EA	-	-	42,711	582	108.46 /MH	63,081	105,792
			CAISSON					480,963	6,549		710,351	1,191,314
			CIVIL WORK					480,963	6,549		710,351	1,191,314
	22.00.00		CONCRETE									
		22.13.00	CONCRETE									
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U1 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE FOUNDATIONS - COMPOSITE RATE	2 UAT AND 1 SST TRANSFORMER SUBSTRUCTURE	600.00 CY	-	-	138,000	4,828	59.71 /MH	288,255	426,255
			CONCRETE FOUNDATIONS - COMPOSITE RATE	BUS DUCT SUPPORTS	333.00 CY	-	-	76,590	2,679	59.71 /MH	159,982	236,572
			CONCRETE FOUNDATIONS - COMPOSITE RATE	OVERHEAD TRANSMISSION LINE STRUCTURAL	50.00 CY	-	-	11,500	402	59.71 /MH	24,021	35,521
			CONCRETE FOUNDATIONS - COMPOSITE RATE	U2 MAIN ELECT BLDG 40'X100'	300.00 CY	-	-	69,000	2,414	59.71 /MH	144,128	213,128
			CONCRETE					364,090	12,737		760,513	1,124,603
			CONCRETE					364,090	12,737		760,513	1,124,603
	23.00.00		STEEL									
		23.99.00	STEEL, MISCELLANEOUS									

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		23.99.00	STEEL, MISCELLANEOUS									
			STEEL, MISCELLANEOUS - AUX SUPPORT STEEL	AUX SUPPORT STEEL	100.00 TN	-	-	271,000	1,954	92.62 /MH	180,982	451,982
			STEEL, MISCELLANEOUS -	BUS DUCT SUPPORTS	167.00 TN	-	-	452,570	3,263	92.62 /MH	302,239	754,809
			STEEL, MISCELLANEOUS -	OVERHEAD TRANSMISSION LINE STRUCTURAL	15.00 TN	-	-	40,650	293	92.62 /MH	27,147	67,797
			STEEL, MISCELLANEOUS					764,220	5,510		510,368	1,274,588
			STEEL					764,220	5,510		510,368	1,274,588
	24.00.00		ARCHITECTURAL									
		24.35.00	PRE-ENGINEERED BUILDING									
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U1 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' FURNISH ONLY	1.00 EA	-	504,000		4,598	51.10 /MH	234,943	738,943
			PRE-ENGINEERED BUILDING - MAIN ELECT BLDG 40'X100'	U2 MAIN ELECT BLDG 40'X100' INSTALLATION	1.00 EA	-			414	92.62 /MH	38,326	38,326
			PRE-ENGINEERED BUILDING				1,008,000		10,023		546,536	1,554,536
			ARCHITECTURAL				1,008,000		10,023		546,536	1,554,536
	41.00.00		ELECTRICAL EQUIPMENT									
		41.13.00	BUS DUCT									
			ISO PHASE, SELF COOLED	TAP BUS EXTENSIONS	200.00 LF	-	315,000		4,828	63.63 /MH	307,179	622,179
			NON SEGREGATED - (600V) (2000A) FGD ONLY		800.00 LF	-	588,000		5,517	63.63 /MH	351,062	939,062
			BUS DUCT				903,000		10,345		658,241	1,561,241
		41.45.00	MOTOR CONTROL CENTER (MCC), COMPLETE									
			MOTOR CONTROL CENTER (MCC), COMPLETE - 480V FGD		12.00 EA	-	636,000		5,931	63.63 /MH	377,392	1,013,392
			MOTOR CONTROL CENTER (MCC), COMPLETE				636,000		5,931		377,392	1,013,392
		41.51.00	POWER TRANSFORMER									
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	1.00 EA	-	875,000		1,379	63.63 /MH	87,766	962,766
			STARTUP, RESERVE AUXILIARY (RAT) - 36/48 MVA 115/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	1.00 EA	-	95,000			/MH		95,000
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	LABOR INCLUDES DRESS OUT AND FILL	2.00 EA	-	1,700,000		2,759	63.63 /MH	175,531	1,875,531
			UNIT AUXILIARY - 36/48 MVA 25/6.9/6.9 KV	HEAVY HAUL FROM RAIL TO PAD	2.00 EA	-	190,000			/MH		190,000
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 2000 KVA		4.00 EA	-	360,000		667	63.63 /MH	42,420	402,420
			POWER TRANSFORMER - 6.9-.48 kV UNIT SUBSTATION X FMRS - 1500 KVA		4.00 EA	-	300,000		598	63.63 /MH	38,032	338,032
			POWER TRANSFORMER				3,520,000		5,402		343,748	3,863,748
		41.55.00	SWITCHGEAR, COMPLETE									
			480 V - REAGENT SWITCHGEAR		4.00 EA	-	212,000		1,977	63.63 /MH	125,797	337,797
			480 V - 480V FGD SWITCHGEAR		4.00 EA	-	840,000		4,138	63.63 /MH	263,297	1,103,297
			6.9 KV - SWITCHGEAR FGD		4.00 EA	-	1,680,000		14,713	63.63 /MH	936,166	2,616,166
			6.9 KV - SWITCHGEAR WALK IN TYPE		3.00 EA	-	660,000		5,810	63.63 /MH	369,712	1,029,712
			SWITCHGEAR, COMPLETE				3,392,000		26,638		1,694,972	5,086,972
		41.99.00	ELECTRICAL EQUIPMENT, MISCELLANEOUS									
			ELECTRICAL EQUIPMENT, MISCELLANEOUS AUX POWER EQUIPMENT		1.00 LT	-	2,840,000		11,494	63.63 /MH	731,379	3,571,379
			ELECTRICAL EQUIPMENT, MISCELLANEOUS				2,840,000		11,494		731,379	3,571,379
			ELECTRICAL EQUIPMENT				11,291,000		59,810		3,805,732	15,096,732
	42.00.00		RACEWAY, CABLE TRAY & CONDUIT									
		42.13.00	CABLE TRAY									
			CABLE TRAY - ALLOTMENT		1.00 LT	-	-	505,000	33,333	61.79 /MH	2,059,667	2,564,667
			CABLE TRAY					505,000	33,333		2,059,667	2,564,667
		42.15.37	CONDUIT, RGS									
			XX IN DIA - CONDUIT ALLOTMENT		1.00 LT	-	-	90,000	74,138	61.79 /MH	4,580,983	4,670,983
			CONDUIT, RGS					90,000	74,138		4,580,983	4,670,983
		42.18.00	DUCT BANK									

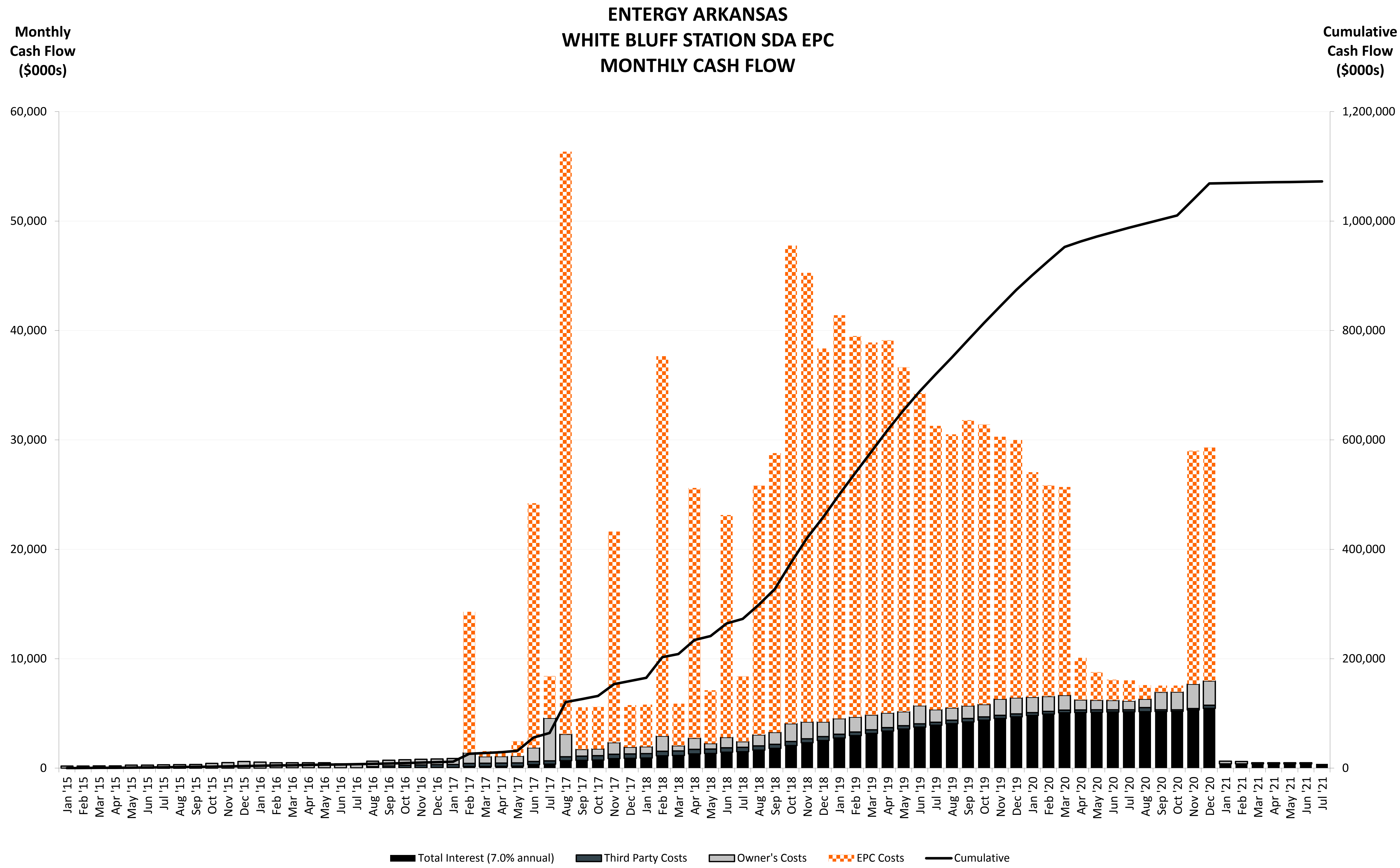
Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
		42.18.00	**DUCT BANK**									
			DUCT BANK - UNDERGROUND DUCT BANKS NOT APPLICABLE		LT	-	-			61.79 /MH		
			RACEWAY, CABLE TRAY & CONDUIT					**595,000**	**107,471**		**6,640,649**	**7,235,649**
	43.00.00		**CABLE**									
		43.10.00	**CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION**									
			CONTROL/INSTRUMENTATION/COMMUNICATION TERMINATION - MISC		201,600.00 LF	-	-	645,120	18,538	82.05 /MH	1,521,037	2,166,157
			CONTROL/INSTRUMENTATION/COMMUNICATION CABLE & TERMINATION					**645,120**	**18,538**		**1,521,037**	**2,166,157**
		43.20.00	**600V CABLE & TERMINATION**									
			600V CABLE - MISC		218,000.00 LF	-	-	1,881,340	30,069	82.05 /MH	2,467,159	4,348,499
			600V CABLE & TERMINATION					**1,881,340**	**30,069**		**2,467,159**	**4,348,499**
		43.40.00	**5/8KV CABLE & TERMINATION**									
			5/8KV #750 KCMIL 1/C CU EPR TS-CPE , FEEDS TO 8KV SWGR BLDG		225,000.00 LF	-	-	5,415,750	23,276	82.05 /MH	1,909,784	7,325,534
			5/8KV MISC		40,200.00 LF	-	-	297,480	10,628	82.05 /MH	871,993	1,169,473
			5/8KV CABLE & TERMINATION					**5,713,230**	**33,903**		**2,781,778**	**8,495,008**
		43.50.00	**15KV CABLE & TERMINATION**									
			15KV CABLE - MISC		22,300.00 LF	-	-	206,721	5,895	82.05 /MH	483,718	690,439
			15KV CABLE & TERMINATION					**206,721**	**5,895**		**483,718**	**690,439**
			CABLE					**8,446,411**	**88,406**		**7,253,692**	**15,700,103**
	51.00.00		**SUBSTATION, SWITCHYARD & TRANSMISSION LINE**									
		51.15.27	**CIRCUIT BREAKER**									
			CIRCUIT BREAKER - SWITCHYARD BAY AND 3 BREAKERS	ADDITION OF A SWITCHYARD BAY IS AVOIDED BY PLACING THE NEW SST NEXT TO THE EXISTING SST AND USING THE SAME OVERHEAD LINE.	0.00 LT	-				55.78 /MH		
		51.15.53	**DISCONNECT SWITCH**									
			115KV, 1200A, VERTICAL BREAK SWITCH WITH INSULATORS,INCLUDING GROUND SWITCH AND WITHOUT MOTORIZED OPERATOR	FOR ISOLATION OF RAT	1.00 EA	-	-	15,000	69	55.78 /MH	3,847	18,847
			DISCONNECT SWITCH					**15,000**	**69**		**3,847**	**18,847**
			SUBSTATION, SWITCHYARD & TRANSMISSION LINE					**15,000**	**69**		**3,847**	**18,847**
			201 ELECTRICAL BOP SYSTEM				**12,299,000**	**10,665,684**	**290,576**		**20,231,688**	**43,196,372**
211			**INSTRUMENTATION AND CONTROLS BOP SYSTEM**									
	44.00.00		**CONTROL & INSTRUMENTATION**									
		44.13.00	**CONTROL SYSTEM**									
			DISTRIBUTED CONTROL SYSTEM (DCS) - I/O POINTS	ESTIMATED BOP 2000 I/O POINTS, (ANOTHER 1000 POINTS PER UNIT ARE INCLUDED IN THE DFGD PROPOSAL PRICES AND ARE NOT INCLUDED HERE)	1.00 LT	-	1,500,000		2,299	64.68 /MH	148,690	1,648,690
			CONTROL SYSTEM				**1,500,000**		**2,299**		**148,690**	**1,648,690**
		44.21.00	**INSTRUMENT**									
			INSTRUMENT - BOP INSTRUMENTS		1.00 LT	-	-	478,000	7,946	82.05 /MH	651,967	1,129,967
			INSTRUMENT - THERMOCOUPLES IN STACK ENTRANCE W ALARM		1.00 LT	-	-	100,000		82.05 /MH		100,000
			INSTRUMENT					**578,000**	**7,946**		**651,967**	**1,229,967**
		44.25.00	**MONITORING EQUIPMENT**									
			CONTINUOUS EMISSION MONITORING SYSTEM (CEMS) - REFURBISHING		2.00 EA	-	-	460,000	625	64.68 /MH	40,444	500,444
			MONITORING EQUIPMENT - LOCAL HMI		3.00 EA	-	-	45,000	14	64.68 /MH	892	45,892

Exhibit B to EAI Comments

Area	Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Crew Rate	Labor Cost	Total Cost
			MONITORING EQUIPMENT					505,000	639		41,336	546,336
			CONTROL & INSTRUMENTATION				1,500,000	1,083,000	10,884		841,993	3,424,993
			211 INSTRUMENTATION AND CONTROLS				**1,500,000**	**1,083,000**	**10,884**		**841,993**	**3,424,993**
			BOP SYSTEM									

ATTACHMENT 2

Conceptual Capital Cost Estimate Cash Flow


ENTERGY ARKANSAS
WHITE BLUFF STATION SDA EPC
MONTHLY CASH FLOW
Monthly
Cash Flow
($000s)
Cumulative
Cash Flow
($000s)
60,000
50,000
40,000
30,000
20,000
10,000
0
1,200,000
1,000,000
800,000
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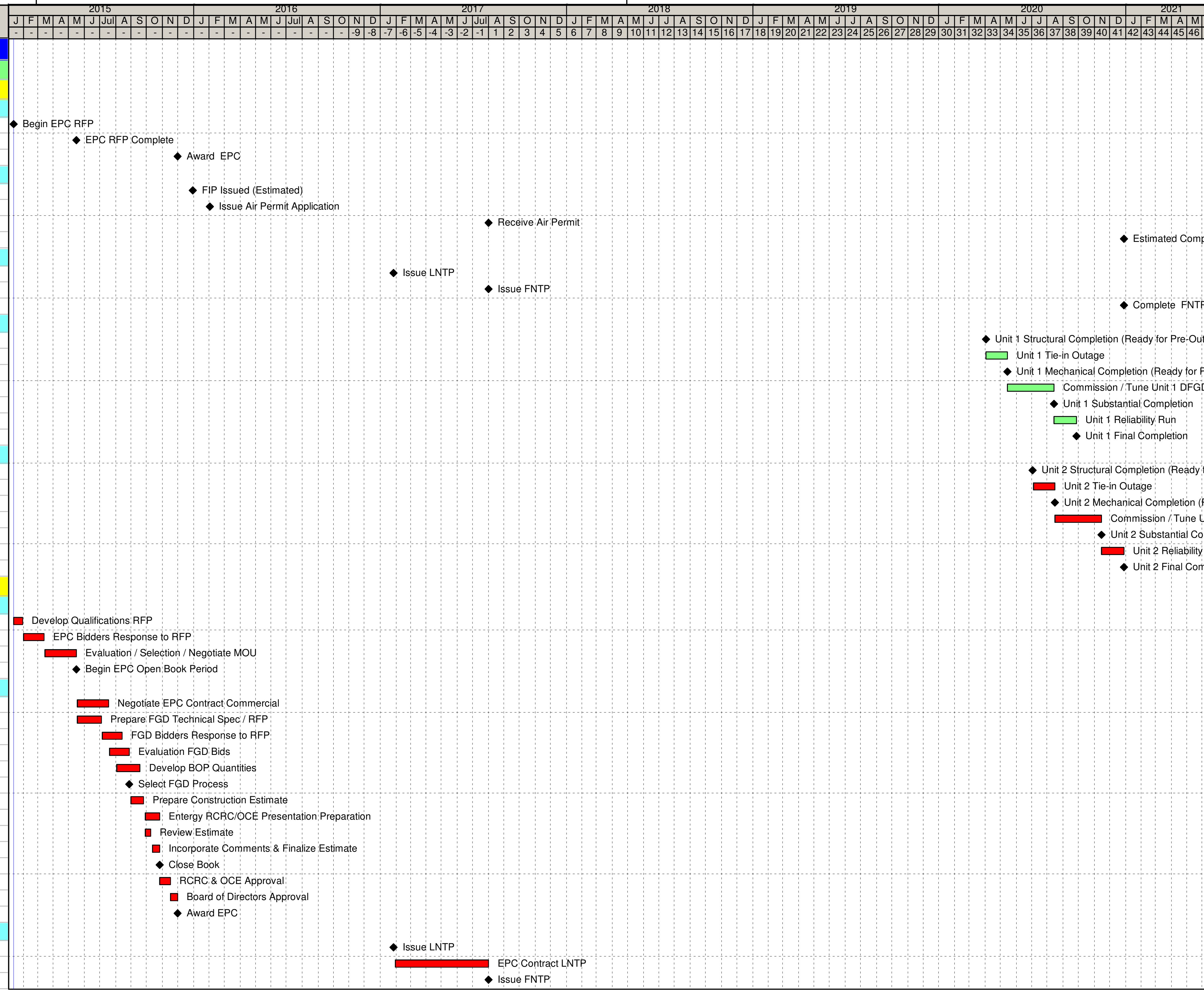
Jul '21
Total Interest (7.0% annual)
Third Party Costs
Owner's Costs
EPC Costs
Cumulative

ATTACHMENT 3

Level 1 Preliminary Execution Schedule

WHITE BLUFF FGD SCHEDULE (December 2020) | 29-May-15 15:26

Activity ID	Activity Name	Orig Dur	Start	Finish
WHITE BLUFF FGD SCHEDULE (December 2020)		1556	13-Jan-15	29-Dec-20
Milestones		1556	13-Jan-15	29-Dec-20
Project Milestones		1556	13-Jan-15	29-Dec-20
EPC RFP		225	13-Jan-15	30-Nov-15
MS010	Begin EPC RFP	0	13-Jan-15	
MS100	EPC RFP Complete	0		15-May-15
MS225	Award EPC	0		30-Nov-15
Permitting		1272	30-Dec-15	29-Dec-20
MS275	FIP Issued (Estimated)	0		30-Dec-15
MS015	Issue Air Permit Application	0		02-Feb-16
MS020	Receive Air Permit	0		31-Jul-17
MS285	Estimated Compliance Date	0		29-Dec-20
LNTP/FNTP		998	27-Jan-17	28-Dec-20
MS260	Issue LNTP	0		27-Jan-17
MS030	Issue FNTP	0		31-Jul-17
MS265	Complete FNTP Period	0		28-Dec-20
Unit 1 & Common Outage, Start-Up & Commissioning		178	02-Apr-20	27-Sep-20
MS0100	Unit 1 Structural Completion (Ready for Pre-Outage)	0		02-Apr-20
MS0110	Unit 1 Tie-in Outage	42	03-Apr-20	14-May-20
MS0120	Unit 1 Mechanical Completion (Ready for Flue Gas)	0		14-May-20
MS0130	Commission / Tune Unit 1 DFGD System	91	15-May-20	13-Aug-20
MS0140	Unit 1 Substantial Completion	0		13-Aug-20
MS0150	Unit 1 Reliability Run	45	14-Aug-20	27-Sep-20
MS0160	Unit 1 Final Completion	0		27-Sep-20*
Unit 2 Outage, Start-Up & Commissioning		179	03-Jul-20	29-Dec-20
MS0200	Unit 2 Structural Completion (Ready for Pre-Outage)	0		03-Jul-20
MS0210	Unit 2 Tie-in Outage	43	04-Jul-20	15-Aug-20
MS0220	Unit 2 Mechanical Completion (Ready for Flue Gas)	0		15-Aug-20
MS0230	Commission / Tune Unit 2 DFGD System	91	16-Aug-20	14-Nov-20
MS0240	Unit 2 Substantial Completion	0		14-Nov-20
MS0250	Unit 2 Reliability Run	45	15-Nov-20	29-Dec-20
MS0260	Unit 2 Final Completion	0		29-Dec-20
Project Overview		1556	13-Jan-15	29-Dec-20
EPC RFP		89	13-Jan-15	15-May-15
OV1000	Develop Qualifications RFP	14	13-Jan-15	30-Jan-15
OV1010	EPC Bidders Response to RFP	30	02-Feb-15	13-Mar-15
OV1020	Evaluation / Selection / Negotiate MOU	45	16-Mar-15	15-May-15
OV1040	Begin EPC Open Book Period	0		15-May-15
EPC Development Phase		141	18-May-15	30-Nov-15
OV1030	Negotiate EPC Contract Commercial	45	18-May-15	17-Jul-15
OV1050	Prepare FGD Technical Spec / RFP	35	18-May-15	03-Jul-15
OV1060	FGD Bidders Response to RFP	30	06-Jul-15	14-Aug-15
OV1070	Evaluation FGD Bids	30	20-Jul-15	28-Aug-15
OV1090	Develop BOP Quantities	35	03-Aug-15	18-Sep-15
OV1080	Select FGD Process	0		28-Aug-15
OV1100	Prepare Construction Estimate	20	31-Aug-15	25-Sep-15
OV1110	Entergy RCRC/OCE Presentation Preparation	21	28-Sep-15	26-Oct-15
OV1103	Review Estimate	10	28-Sep-15	09-Oct-15
OV1105	Incorporate Comments & Finalize Estimate	11	12-Oct-15	26-Oct-15
OV1120	Close Book	0		26-Oct-15
OV1130	RCRC & OCE Approval	15	27-Oct-15	16-Nov-15
OV1140	Board of Directors Approval	10	17-Nov-15	30-Nov-15
OV1145	Award EPC	0		30-Nov-15
LNTP		132	27-Jan-17	01-Aug-17
OV1150	Issue LNTP	0		27-Jan-17
OV1160	EPC Contract LNTP	132	30-Jan-17	01-Aug-17
OV1170	Issue FNTP	0		01-Aug-17

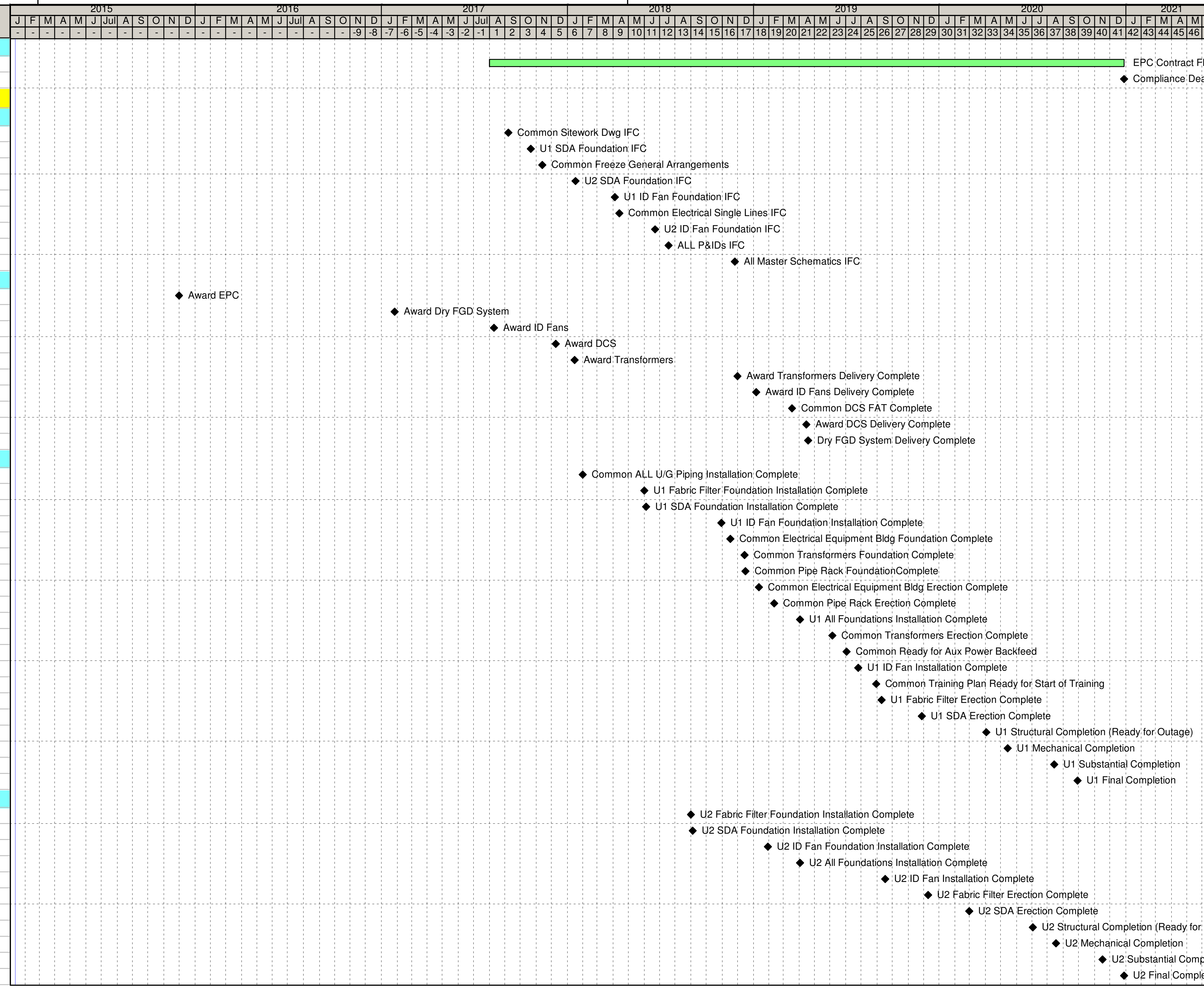


Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

Activity ID	Activity Name	Ori Dur	Start	Finish
FNTP		890	02-Aug-17	29-Dec-20
OV1180	EPC Contract FNTP Period	889	02-Aug-17	28-Dec-20
OV1230	Compliance Deadline	0		29-Dec-20*
EPC Milestones		1292	30-Nov-15	29-Dec-20
Engineering		308	07-Sep-17	26-Nov-18
EPC325	Common Sitework Dwg IFC	0		07-Sep-17
EPC345	U1 SDA Foundation IFC	0		20-Oct-17
EPC340	Common Freeze General Arrangements	0		13-Nov-17
EPC510	U2 SDA Foundation IFC	0		16-Jan-18
EPC350	U1 ID Fan Foundation IFC	0		03-Apr-18
EPC320	Common Electrical Single Lines IFC	0		13-Apr-18
EPC485	U2 ID Fan Foundation IFC	0		22-Jun-18
EPC355	ALL P&IDs IFC	0		18-Jul-18
EPC240	All Master Schematics IFC	0		26-Nov-18
Procurement		858	30-Nov-15	19-Apr-19
EPC010	Award EPC	0		30-Nov-15
EPC100	Award Dry FGD System	0		27-Jan-17
EPC110	Award ID Fans	0		09-Aug-17
EPC335	Award DCS	0		08-Dec-17
EPC315	Award Transformers	0		15-Jan-18
EPC545	Award Transformers Delivery Complete	0		30-Nov-18
EPC535	Award ID Fans Delivery Complete	0		07-Jan-19
EPC415	Common DCS FAT Complete	0		18-Mar-19
EPC540	Award DCS Delivery Complete	0		15-Apr-19
EPC530	Dry FGD System Delivery Complete	0		19-Apr-19
Unit 1 & Common Construction & Commissioning		677	30-Jan-18	28-Sep-20
EPC425	Common ALL U/G Piping Installation Complete	0		30-Jan-18
EPC370	U1 Fabric Filter Foundation Installation Complete	0		01-Jun-18
EPC360	U1 SDA Foundation Installation Complete	0		05-Jun-18
EPC365	U1 ID Fan Foundation Installation Complete	0		30-Oct-18
EPC395	Common Electrical Equipment Bldg Foundation Complete	0		16-Nov-18
EPC405	Common Transformers Foundation Complete	0		14-Dec-18
EPC460	Common Pipe Rack FoundationComplete	0		17-Dec-18
EPC400	Common Electrical Equipment Bldg Erection Complete	0		11-Jan-19
EPC390	Common Pipe Rack Erection Complete	0		11-Feb-19
EPC310	U1 All Foundations Installation Complete	0		02-Apr-19
EPC410	Common Transformers Erection Complete	0		05-Jun-19
EPC435	Common Ready for Aux Power Backfeed	0		02-Jul-19
EPC380	U1 ID Fan Installation Complete	0		25-Jul-19
EPC420	Common Training Plan Ready for Start of Training	0		29-Aug-19
EPC385	U1 Fabric Filter Erection Complete	0		09-Sep-19
EPC375	U1 SDA Erection Complete	0		28-Nov-19
EPC440	U1 Structural Completion (Ready for Outage)	0		02-Apr-20
EPC445	U1 Mechanical Completion	0		14-May-20
EPC450	U1 Substantial Completion	0		13-Aug-20
EPC455	U1 Final Completion	0		28-Sep-20
Unit 2 Construction & Commissioning		593	31-Aug-18	29-Dec-20
EPC475	U2 Fabric Filter Foundation Installation Complete	0		31-Aug-18
EPC515	U2 SDA Foundation Installation Complete	0		04-Sep-18
EPC490	U2 ID Fan Foundation Installation Complete	0		29-Jan-19
EPC465	U2 All Foundations Installation Complete	0		02-Apr-19
EPC495	U2 ID Fan Installation Complete	0		16-Sep-19
EPC470	U2 Fabric Filter Erection Complete	0		09-Dec-19
EPC505	U2 SDA Erection Complete	0		28-Feb-20
EPC520	U2 Structural Completion (Ready for Outage)	0		03-Jul-20
EPC500	U2 Mechanical Completion	0		17-Aug-20
EPC525	U2 Substantial Completion	0		16-Nov-20
EPC480	U2 Final Completion	0		29-Dec-20



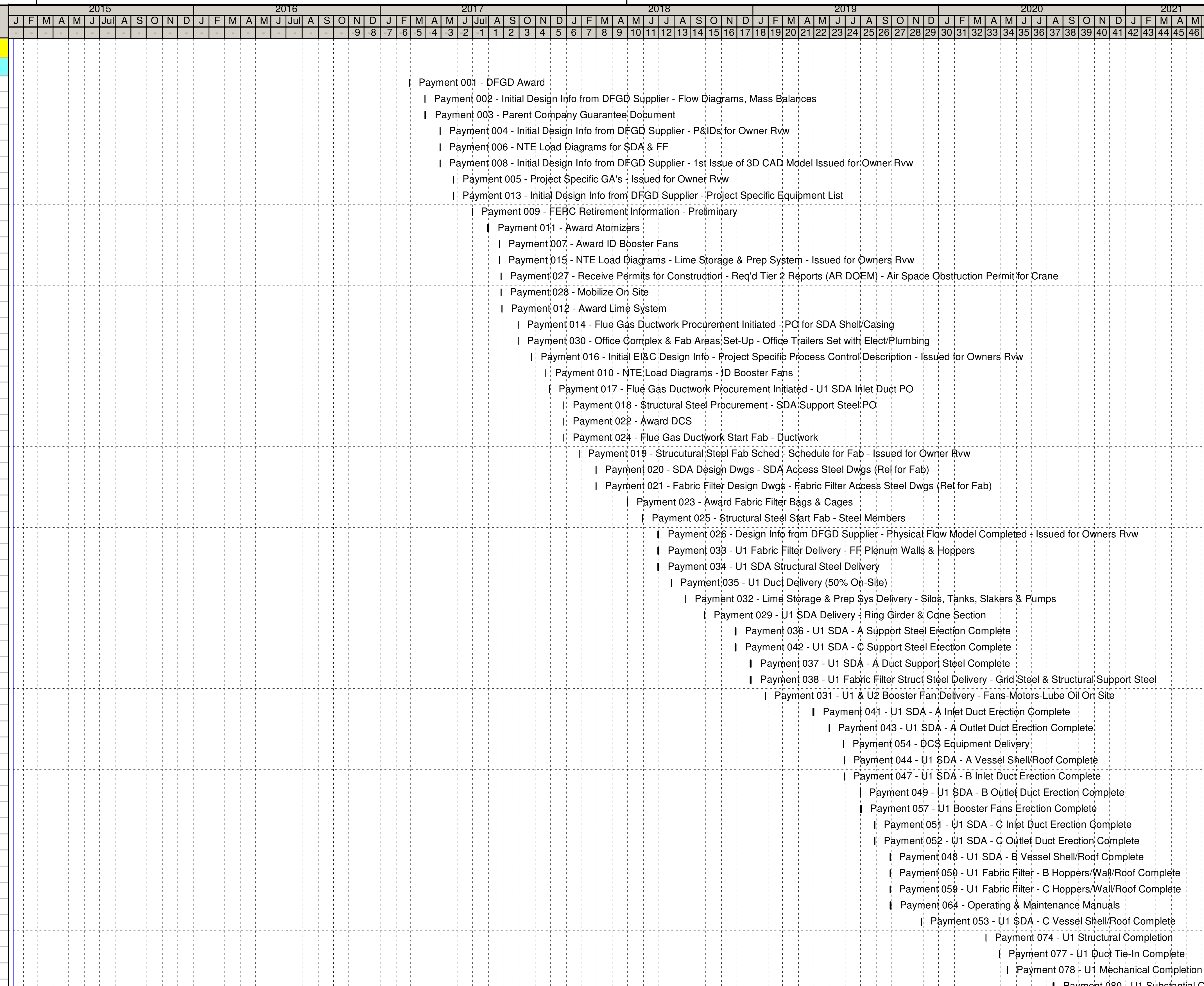
Remaining Work — Actual Work — WBS Summary

Critical Remaining Work — Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

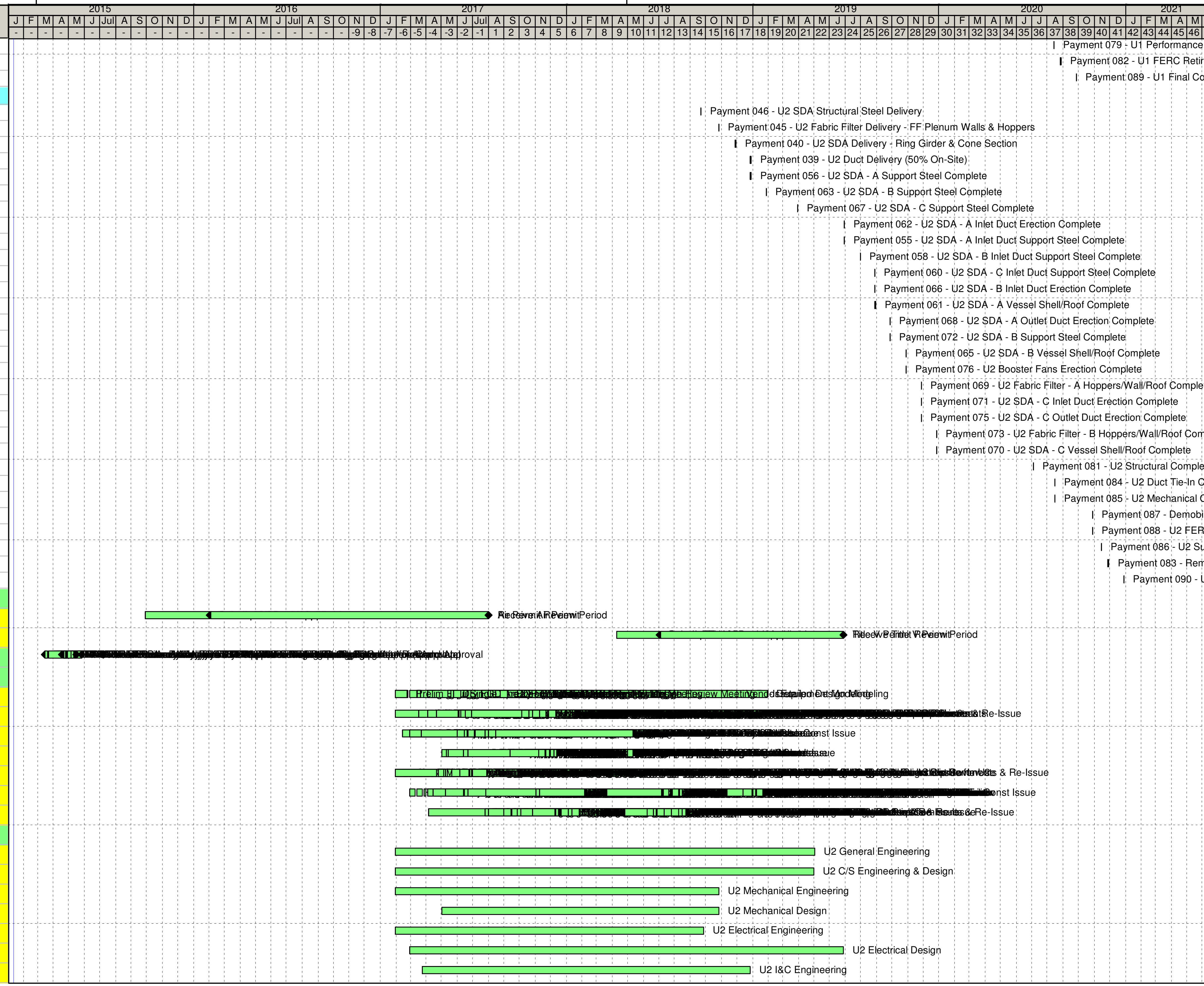
Activity ID	Activity Name	Ori Dur	Start	Finish
Payment Milestones		1401	28-Feb-17	29-Dec-20
Unit 1 & Common		1308	28-Feb-17	27-Sep-20
PAY001	Payment 001 - DFGD Award	1	28-Feb-17	28-Feb-17
PAY002	Payment 002 - Initial Design Info from DFGD Supplier - Flow ...	1	29-Mar-17	29-Mar-17
PAY003	Payment 003 - Parent Company Guarantee Document	1	30-Mar-17	30-Mar-17
PAY004	Payment 004 - Initial Design Info from DFGD Supplier - P&IDs...	1	28-Apr-17	28-Apr-17
PAY006	Payment 006 - NTE Load Diagrams for SDA & FF	1	28-Apr-17	28-Apr-17
PAY008	Payment 008 - Initial Design Info from DFGD Supplier - 1st Iss...	1	28-Apr-17	28-Apr-17
PAY005	Payment 005 - Project Specific GA's - Issued for Owner Rvw	1	25-May-17	25-May-17
PAY013	Payment 013 - Initial Design Info from DFGD Supplier - Projec...	1	25-May-17	25-May-17
PAY009	Payment 009 - FERC Retirement Information - Preliminary	1	30-Jun-17	30-Jun-17
PAY011	Payment 011 - Award Atomizers	1	31-Jul-17	31-Jul-17
PAY007	Payment 007 - Award ID Booster Fans	1	22-Aug-17	22-Aug-17
PAY015	Payment 015 - NTE Load Diagrams - Lime Storage & Prep Sy...	1	22-Aug-17	22-Aug-17
PAY027	Payment 027 - Receive Permits for Construction - Req'd Tier ...	1	25-Aug-17	25-Aug-17
PAY028	Payment 028 - Mobilize On Site	1	26-Aug-17	26-Aug-17
PAY012	Payment 012 - Award Lime System	1	28-Aug-17	28-Aug-17
PAY014	Payment 014 - Flue Gas Ductwork Procurement Initiated - PO...	1	28-Sep-17	28-Sep-17
PAY030	Payment 030 - Office Complex & Fab Areas Set-Up - Office Tr...	1	28-Sep-17	28-Sep-17
PAY016	Payment 016 - Initial EI&C Design Info - Project Specific Proc...	1	24-Oct-17	24-Oct-17
PAY010	Payment 010 - NTE Load Diagrams - ID Booster Fans	1	22-Nov-17	22-Nov-17
PAY017	Payment 017 - Flue Gas Ductwork Procurement Initiated - U1 ...	1	28-Nov-17	28-Nov-17
PAY018	Payment 018 - Structural Steel Procurement - SDA Support St...	1	26-Dec-17	27-Dec-17
PAY022	Payment 022 - Award DCS	1	26-Dec-17	27-Dec-17
PAY024	Payment 024 - Flue Gas Ductwork Start Fab - Ductwork	1	26-Dec-17	27-Dec-17
PAY019	Payment 019 - Strucutural Steel Fab Sched - Schedule for Fa...	1	26-Jan-18	26-Jan-18
PAY020	Payment 020 - SDA Design Dwgs - SDA Access Steel Dwgs (...	1	28-Feb-18	28-Feb-18
PAY021	Payment 021 - Fabric Filter Design Dwgs - Fabric Filter Acces...	1	28-Feb-18	28-Feb-18
PAY023	Payment 023 - Award Fabric Filter Bags & Cages	1	30-Apr-18	30-Apr-18
PAY025	Payment 025 - Structural Steel Start Fab - Steel Members	1	30-May-18	30-May-18
PAY026	Payment 026 - Design Info from DFGD Supplier - Physical Flo...	1	30-Jun-18	30-Jun-18
PAY033	Payment 033 - U1 Fabric Filter Delivery - FF Plenum Walls & ...	1	30-Jun-18	30-Jun-18
PAY034	Payment 034 - U1 SDA Structural Steel Delivery	1	30-Jun-18	30-Jun-18
PAY035	Payment 035 - U1 Duct Delivery (50% On-Site)	1	25-Jul-18	25-Jul-18
PAY032	Payment 032 - Lime Storage & Prep Sys Delivery - Silos, Tan...	1	23-Aug-18	23-Aug-18
PAY029	Payment 029 - U1 SDA Delivery - Ring Girder & Cone Section	1	28-Sep-18	28-Sep-18
PAY036	Payment 036 - U1 SDA - A Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY042	Payment 042 - U1 SDA - C Support Steel Erection Complete	1	28-Nov-18	28-Nov-18
PAY037	Payment 037 - U1 SDA - A Duct Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY038	Payment 038 - U1 Fabric Filter Struct Steel Delivery - Grid Ste...	1	28-Dec-18	28-Dec-18
PAY031	Payment 031 - U1 & U2 Booster Fan Delivery - Fans-Motors-L...	1	26-Jan-19	26-Jan-19
PAY041	Payment 041 - U1 SDA - A Inlet Duct Erection Complete	1	30-Apr-19	30-Apr-19
PAY043	Payment 043 - U1 SDA - A Outlet Duct Erection Complete	1	30-May-19	30-May-19
PAY054	Payment 054 - DCS Equipment Delivery	1	28-Jun-19	28-Jun-19
PAY044	Payment 044 - U1 SDA - A Vessel Shell/Roof Complete	1	29-Jun-19	29-Jun-19
PAY047	Payment 047 - U1 SDA - B Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY049	Payment 049 - U1 SDA - B Outlet Duct Erection Complete	1	31-Jul-19	31-Jul-19
PAY057	Payment 057 - U1 Booster Fans Erection Complete	1	01-Aug-19	01-Aug-19
PAY051	Payment 051 - U1 SDA - C Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY052	Payment 052 - U1 SDA - C Outlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY048	Payment 048 - U1 SDA - B Vessel Shell/Roof Complete	1	27-Sep-19	27-Sep-19
PAY050	Payment 050 - U1 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY059	Payment 059 - U1 Fabric Filter - C Hoppers/Wall/Roof Complete	1	27-Sep-19	27-Sep-19
PAY064	Payment 064 - Operating & Maintenance Manuals	1	28-Sep-19	28-Sep-19
PAY053	Payment 053 - U1 SDA - C Vessel Shell/Roof Complete	1	28-Nov-19	28-Nov-19
PAY074	Payment 074 - U1 Structural Completion	1	02-Apr-20	02-Apr-20
PAY077	Payment 077 - U1 Duct Tie-In Complete	1	29-Apr-20	29-Apr-20
PAY078	Payment 078 - U1 Mechanical Completion	1	15-May-20	15-May-20
PAY080	Payment 080 - U1 Substantial Completion	1	13-Aug-20	13-Aug-20



Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

Activity ID	Activity Name	Ori Dur	Start	Finish
PAY079	Payment 079 - U1 Performance Test Report	1	14-Aug-20	14-Aug-20
PAY082	Payment 082 - U1 FERC Retirement Information	1	27-Aug-20	27-Aug-20
PAY089	Payment 089 - U1 Final Completion	1	27-Sep-20	27-Sep-20
Unit 2		830	22-Sep-18	29-Dec-20
PAY046	Payment 046 - U2 SDA Structural Steel Delivery	1	22-Sep-18	22-Sep-18
PAY045	Payment 045 - U2 Fabric Filter Delivery - FF Plenum Walls & ...	1	27-Oct-18	27-Oct-18
PAY040	Payment 040 - U2 SDA Delivery - Ring Girder & Cone Section	1	28-Nov-18	28-Nov-18
PAY039	Payment 039 - U2 Duct Delivery (50% On-Site)	1	28-Dec-18	28-Dec-18
PAY056	Payment 056 - U2 SDA - A Support Steel Complete	1	28-Dec-18	28-Dec-18
PAY063	Payment 063 - U2 SDA - B Support Steel Complete	1	28-Jan-19	28-Jan-19
PAY067	Payment 067 - U2 SDA - C Support Steel Complete	1	30-Mar-19	30-Mar-19
PAY062	Payment 062 - U2 SDA - A Inlet Duct Erection Complete	1	29-Jun-19	29-Jun-19
PAY055	Payment 055 - U2 SDA - A Inlet Duct Support Steel Complete	1	30-Jun-19	30-Jun-19
PAY058	Payment 058 - U2 SDA - B Inlet Duct Support Steel Complete	1	31-Jul-19	31-Jul-19
PAY060	Payment 060 - U2 SDA - C Inlet Duct Support Steel Complete	1	28-Aug-19	28-Aug-19
PAY066	Payment 066 - U2 SDA - B Inlet Duct Erection Complete	1	28-Aug-19	28-Aug-19
PAY061	Payment 061 - U2 SDA - A Vessel Shell/Roof Complete	1	29-Aug-19	29-Aug-19
PAY068	Payment 068 - U2 SDA - A Outlet Duct Erection Complete	1	27-Sep-19	27-Sep-19
PAY072	Payment 072 - U2 SDA - B Support Steel Complete	1	27-Sep-19	27-Sep-19
PAY065	Payment 065 - U2 SDA - B Vessel Shell/Roof Complete	1	29-Oct-19	29-Oct-19
PAY076	Payment 076 - U2 Booster Fans Erection Complete	1	29-Oct-19	29-Oct-19
PAY069	Payment 069 - U2 Fabric Filter - A Hoppers/Wall/Roof Complete	1	28-Nov-19	28-Nov-19
PAY071	Payment 071 - U2 SDA - C Inlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY075	Payment 075 - U2 SDA - C Outlet Duct Erection Complete	1	28-Nov-19	28-Nov-19
PAY073	Payment 073 - U2 Fabric Filter - B Hoppers/Wall/Roof Complete	1	27-Dec-19	27-Dec-19
PAY070	Payment 070 - U2 SDA - C Vessel Shell/Roof Complete	1	28-Dec-19	28-Dec-19
PAY081	Payment 081 - U2 Structural Completion	1	04-Jul-20	04-Jul-20
PAY084	Payment 084 - U2 Duct Tie-In Complete	1	16-Aug-20	16-Aug-20
PAY085	Payment 085 - U2 Mechanical Completion	1	16-Aug-20	16-Aug-20
PAY087	Payment 087 - Demobilization Complete	1	28-Oct-20	28-Oct-20
PAY088	Payment 088 - U2 FERC Retirement Information	1	28-Oct-20	28-Oct-20
PAY086	Payment 086 - U2 Substantial Completion	1	15-Nov-20	15-Nov-20
PAY083	Payment 083 - Removal of Fabrication Tables Complete	1	28-Nov-20	28-Nov-20
PAY090	Payment 090 - U2 Final Completion	1	29-Dec-20	29-Dec-20
Permitting		949	29-Sep-15	27-Jun-19
Air Permit		465	29-Sep-15	31-Jul-17
Title V Operating Permit		310	09-Apr-18	27-Jun-19
TRAX Boiler Pressure Analysis		81	16-Mar-15	08-Jul-15
U1 Engineering		540	30-Jan-17	15-Mar-19
U1 General Engineering & Design		507	30-Jan-17	29-Jan-19
U1 C/S/A Engineering and Design		500	30-Jan-17	18-Jan-19
U1 Mechanical Engineering		364	13-Feb-17	18-Jul-18
U1 Mechanical Design		309	01-May-17	18-Jul-18
U1 Electrical Engineering		344	30-Jan-17	05-Jun-18
U1 Electrical Design		520	27-Feb-17	15-Mar-19
U1 I&C Engineering		368	06-Apr-17	17-Sep-18
U2 Engineering		630	30-Jan-17	28-Jun-19
U2 General Engineering & Design		590	30-Jan-17	03-May-19
U2 C/S/A Engineering and Design		587	30-Jan-17	30-Apr-19
U2 Mechanical Engineering		455	30-Jan-17	26-Oct-18
U2 Mechanical Design		389	02-May-17	26-Oct-18
U2 Electrical Engineering		434	30-Jan-17	27-Sep-18
U2 Electrical Design		610	27-Feb-17	28-Jun-19
U2 I&C Engineering		460	24-Mar-17	27-Dec-18

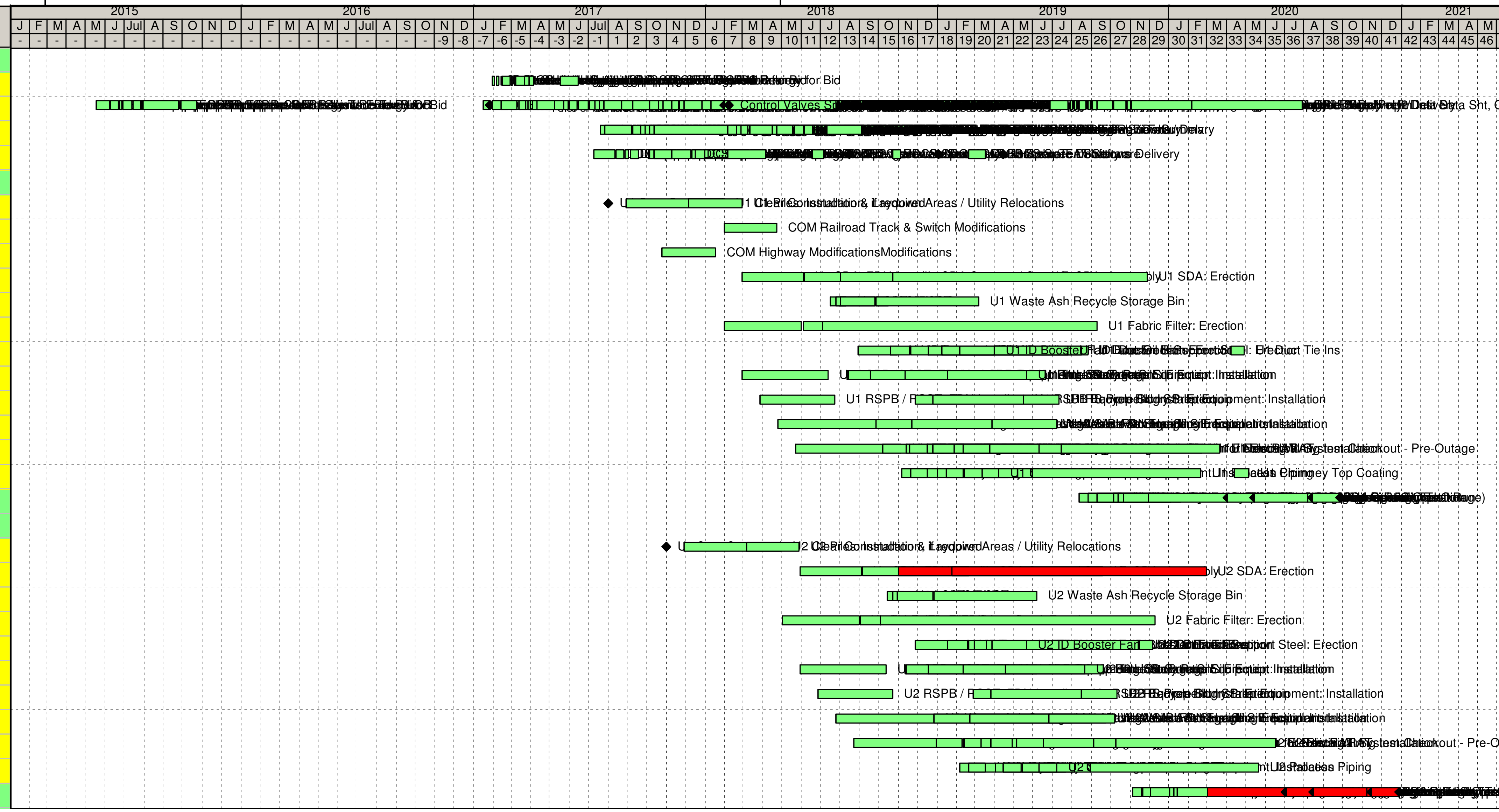


Remaining Work · Actual Work · WBS Summary · Critical Remaining Work · Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

Activity ID	Activity Name	Ori Dur	Start	Finish
	Procurement	1357	18-May-15	28-Jul-20
	C/S/A Procurement	98	30-Jan-17	15-Jun-17
	Mechanical Procurement	1357	18-May-15	28-Jul-20
	Electrical Procurement	347	20-Jul-17	30-Nov-18
	I&C Procurement	448	10-Jul-17	15-Apr-19
	U1 Construction	720	02-Aug-17	05-May-20
	U1 Sitework	150	02-Aug-17	27-Feb-18
	U1 Railroad Track & Switch Mods	60	31-Jan-18	24-Apr-18
	U1 Highway Mods	60	25-Oct-17	16-Jan-18
	U1 SDA	457	28-Feb-18	28-Nov-19
	U1 Field Fabricated Tanks	170	16-Jul-18	08-Mar-19
	U1 Fabric Filter	419	31-Jan-18	09-Sep-19
	U1 ID Booster Fans / Ductwork	436	29-Aug-18	29-Apr-20
	U1 Lime Slurry	343	28-Feb-18	21-Jun-19
	U1 Recycle Slurry	337	29-Mar-18	12-Jul-19
	U1 Byproduct Handling	314	25-Apr-18	08-Jul-19
	U1 Auxiliary Power	478	23-May-18	20-Mar-20
	U1 Balance of Plant	390	07-Nov-18	05-May-20
	U1 System Testing and Commissioning	294	13-Aug-19	27-Sep-20
	U2 Construction	686	01-Nov-17	17-Jun-20
	U2 Sitework	150	01-Nov-17	29-May-18
	U2 SDA	458	30-May-18	28-Feb-20
	U2 Field Fabricated Tanks	170	15-Oct-18	07-Jun-19
	U2 Fabric Filter	419	02-May-18	09-Dec-19
	U2 ID Booster Fans / Ductwork	268	28-Nov-18	07-Dec-19
	U2 Lime Slurry	343	30-May-18	20-Sep-19
	U2 Recycle Slurry	337	28-Jun-18	11-Oct-19
	U2 Byproduct Handling	314	25-Jul-18	07-Oct-19
	U2 Auxiliary Power	476	22-Aug-18	17-Jun-20
	U2 Balance of Plant	337	06-Feb-19	21-May-20
	U2 System Testing and Commissioning	301	05-Nov-19	29-Dec-20



Remaining Work | Actual Work | WBS Summary
Critical Remaining Work | Milestone

TASK filter: Exclude WBS Activities_1.

Exhibit B to EAI Comments

ATTACHMENT 4

Milestone Progress Payment Schedule

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
1	Feb-17	Award Dry FGD Contract Execution	1.51	1.51
2	Mar-17	DFGD Supplier - Process Flow Diagrams and Mass Balances	0.06	1.57
3	Apr-17	DFGD Supplier - P&ID Drawings	0.06	1.63
4	May-17	DFGD Supplier - General Arrangement Drawings NTE Load Diagrams	0.16	1.79
5	Jun-17	DFGD Supplier - Preliminary 3D CAD Model Award Booster Fans	2.62	4.41
6	Jul-17	NTE Load Diagrams Award Atomizers	0.45	4.86
7	Aug-17	DFGD Supplier - Equipment Lists Award Lime System	6.24	11.10
8	Sep-17	Flue Gas Ductwork Procurement Initiated	0.45	11.55
9	Oct-17	Initial EI&C Design Information NTE Load Diagrams	0.45	12.00
10	Nov-17	Flue Gas Ductwork Procurement Initiated	2.26	14.26
11	Dec-17	Structural Steel Procurement Initiated	0.45	14.71
12	Jan-18	Structural Steel Fabrication Schedule Complete	0.45	15.16
13	Feb-18	SDA and Fabric Filter Design Drawings	4.07	19.23
14	Mar-18	Award DCS	0.45	19.68
15	Apr-18	Award Fabric Filter Bags and Cages Flue Gas Ductwork Start of Fabrication	2.68	22.36
16	May-18	Structural Steel Start of Fabrication	0.57	22.93
17	Jun-18	Physical Flow Model Completed	2.38	25.31
18	Jul-18	Receive Permits for Construction	0.70	26.01
19	Aug-18	Mobilize On-Site	2.67	28.68
20	Sep-18	Unit 1 SDA Delivery Office Complex and Fabrication Areas Set-Up	2.99	31.67
21	Oct-18	Unit 1 and Unit 2 Booster Fan Delivery Lime Storage and Preparation System Delivery Unit 1 Fabric Filter Delivery	5.12	36.79
22	Nov-18	Unit 1 SDA Structural Steel Delivery Unit 1 Duct Delivery Unit 1 SDA-A Support Steel Erection Complete	4.81	41.60
23	Dec-18	Unit 1 SDA-A Inlet Duct Support Steel Complete Unit 1 Fabric Filter Structural Steel Delivery Unit 2 Duct Delivery	4.00	45.60
24	Jan-19	Unit 2 SDA Delivery Unit 1 SDA-A Inlet Duct Erection Complete Unit 1 SDA-C Support Steel Erection Complete	4.32	49.92
25	Feb-19	Unit 1 SDA-A Outlet Duct Erection Complete Unit 1 SDA-A Vessel Shell/Roof Complete Unit 2 Fabric Filter Delivery	4.08	54.00
26	Mar-19	Unit 2 Structural Steel Delivery Unit 1 SDA-B Inlet Duct Erection Complete Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete	3.99	57.99

Attachment 4

MONTHLY PROGRESS PAYMENT SCHEDULE

Month	Date	Milestone	Individual Payment (%)	Cumulative Payment (%)
27	Apr-19	Unit 1 SDA-B Vessel Shell/Roof Complete	3.99	61.98
		Unit 1 SDA-B Outlet Duct Erection Complete		
		Unit 1 Fabric Filter-B Hoppers/Wall/Roof Complete		
28	May-19	Unit 1 SDA-C Inlet Duct Erection Complete	3.69	65.67
		Unit 1 SDA-C Outlet Duct Erection Complete		
29	Jun-19	Unit 1 SDA-C Vessel Shell/Roof Complete	3.35	69.02
		DCS Equipment Delivery		
		Unit 2 SDA-A Inlet Duct Support Steel Complete		
		Unit 2 SDA-A Support Steel Complete		
30	Jul-19	Unit 1 Booster Fans Erection Complete	3.04	72.06
		Unit 2 SDA-B Inlet Duct Support Steel Complete		
		Unit 1 Fabric Filter-C Hoppers/Wall/Roof Complete		
31	Aug-19	Unit 2 SDA-C Inlet Duct Support Steel Complete	2.93	74.99
		Unit 2 SDA-A Vessel Shell/Roof Complete		
		Unit 2 SDA-A Inlet Duct Erection Complete		
32	Sep-19	Unit 2 SDA-B Support Steel Complete	3.06	78.05
		Operating and Maintenance Manuals		
33	Oct-19	Unit 2 SDA-B Vessel Shell/Roof Complete	3.00	81.05
		Unit 2 SDA-B Inlet Duct Erection Complete		
		Unit 2 SDA-C Support Steel Complete		
34	Nov-19	Unit 2 SDA-A Outlet Duct Erection Complete	2.81	83.86
		Unit 2 Fabric Filter-A Hoppers/Wall/Roof Complete		
35	Dec-19	Unit 2 SDA-C Vessel Shell/Roof Complete	2.76	86.62
		Unit 2 SDA-C Inlet Duct Erection Complete		
36	Jan-20	Unit 2 SDA-B Outlet Duct Erection Complete	2.41	89.03
		Unit 2 Fabric Filter-B Hoppers/Wall/Roof Complete		
		Unit 1 Structural Completion		
37	Feb-20	Unit 2 SDA-C Outlet Duct Erection Complete	2.26	91.29
		Unit 2 Booster Fans Erection Complete		
38	Mar-20	Unit 1 Duct Tie-In Complete	2.23	93.52
39	Apr-20	Unit 1 Mechanical Completion	0.45	93.97
40	May-20	Unit 1 Performance Test Report	0.30	94.27
41	Jun-20	Unit 1 Substantial Completion	0.22	94.49
		Unit 2 Structural Completion		
42	Jul-20	Removal of Fabrication Tables Complete	0.22	94.71
43	Aug-20	Unit 2 Duct Tie-In Complete	0.15	94.86
44	Sep-20	Unit 2 Mechanical Completion	0.07	94.93
45	Oct-20	Unit 2 Substantial Completion	0.07	95.00
		Demobilization Complete		
46	Nov-20	Unit 1 Final Acceptance	2.50	97.50
47	Dec-20	Unit 2 Final Acceptance	2.50	100.00

ATTACHMENT 5

S&L Estimating Documentation:

Indirects and Construction Equipment included in Crew Rates

Indirects and Construction Equipment included in Crew Rates

Typical Construction Equipment included in our Crew Rates

- Air compressor
- Air tugger
- Crane, 5 ton
- Crane, 15 ton mobile
- Crane, 35 ton
- Crane, 50 ton
- Crane, 60 ton
- Dozer
- Finishing machine
- Flat bed trailer
- Fork lift
- Front end loader
- Generator
- Grader
- Pickup truck
- Powdered riding buggy
- Roller, sheepsfoot
- Roller, vibratory
- Radial saw
- Scraper
- Stress relieving machine
- Tremie
- Truck mounted concrete pump
- Vibrator
- Water wagon
- Welding machine
- Wire puller

Site Indirects included in Crew Rates

- Job Supervision-Field Staff
- Administration-Field Staff
- Personnel Hiring
- Craft Superintendents
- Safety / Purchasing/Expediting-Field Staff
- Material Control-Field Staff
- Engineering Liaison-Field Staff
- Project Controls-Field Staff
- Cost/Schedule Controls-Field Staff
- Quality Control Inspection-Field Staff
- Project Office Supplies-Field Staff
- Computer Expenses
- Service Trucks/Supplies
- Field and Shop Mechanics and Supplies
- Subcontract Administration
- Warehousing-Field Staff
- Field Surveying
- Water & Ice
- Sanitation and Cleanup
- Move In/Move Out
- Detours/Barricades/Flags
- Security
- Temp. Utilities/Distr/Hookup
- Temporary Site Improvement
- Temporary Facilities/Buildings
- Utilities Consumption
- Employee Expenses
- Legal Expenses/Claims
- Permits and Fees
- Timekeeping

ATTACHMENT 6

S&L Estimating Documentation:

Escalation Projections

Entergy
White Bluff DGFD Project
Escalation Projections

Basis: Pine Bluff Arkansas Labor rates as published in RS Means	Yearly Base Rates + Fringes										
Craft Description	2009	2010	2011	2012	2013	2014	% increase in past 1 year	% increase in past 2 years	% increase in past 3 years	% increase in past 5 years	Projected Potential overall % labor increase next 5 years.
Boilermaker	$38.59	$41.59	$41.59	$41.59	$43.10	$44.39	2.99%	6.73%	6.73%	15.03%	
Iron worker	$28.06	$30.44	$30.44	$30.44	$32.05	$34.00	6.08%	11.70%	11.70%	21.17%	
Pipe Fitter	$25.28	$31.65	$31.65	$31.65	$35.56	$35.56	0.00%	12.35%	12.35%	40.66%	
Electrician	$35.74	$35.74	$35.74	$35.74	$36.95	$36.95	0.00%	3.39%	3.39%	3.39%	
Common Laborer	$16.83	$17.47	$17.47	$17.47	$17.47	$17.47	0.00%	0.00%	0.00%	3.80%	
Average increase in five major crafts							1.82%	6.83%	6.83%	16.81%	**18%**

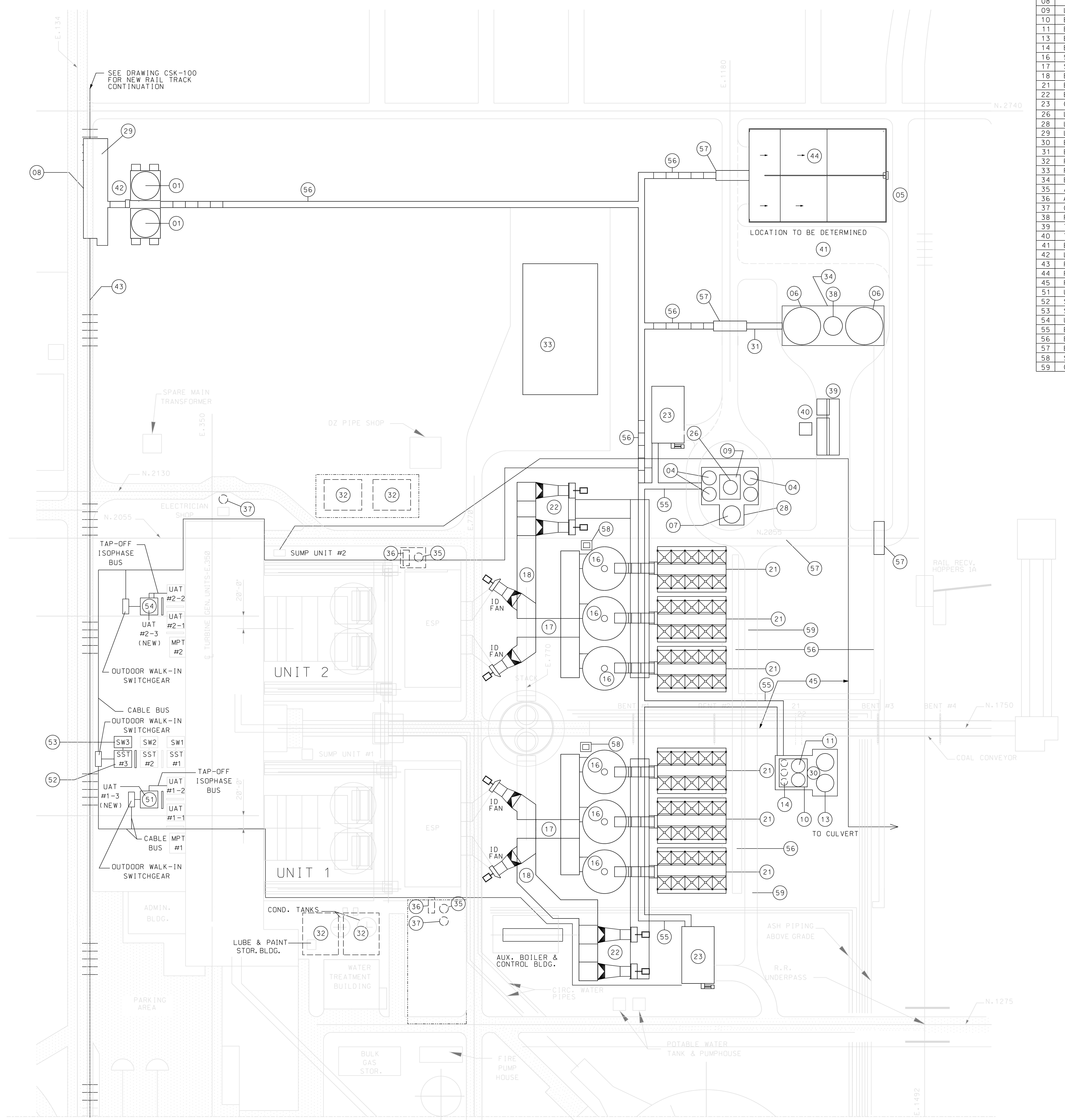
Misc Material and Equipment (Please see Note 1)									% increase in past 3 years	% increase in past 5 years	Projected Potential overall % increase next 5 years.
Construction & Building Index									8%	15%	17.00%
Material Price, Construction Mat.									8%	7%	10.00%
Plant Cost Index									no increase	slightly negative	5.00%
Civil Work									8%	14%	15.00%
Steel - ductwork									no increase	slightly negative	8.00%
Steel - rolled shape									8%	no increase	10.00%
Architectural									5%	4%	8.00%
Overall mechanical equipment									4%	1%	7.00%
Overall piping									6%	11%	12.00%
Overall electrical equipment									9%	17%	18.00%
Raceway, Cable Tray, & Conduit									8%	slightly negative	10.00%
Electrical cable									14%	7%	15.00%
Controls & Instrumentation									1%	1%	5.00%
Average overall increase for Power back-fit projects									**7%**	**9%**	**11%**

Note 1: From major industrial sources such as BLS, Chemical Engineering, Handy Whitman, ENR Commodity pricing (20 city average),

ATTACHMENT 7

Conceptual General Arrangement Drawing

LEGEND	
01	LIME STORAGE SILOS
03	NOT USED
04	LIME SLURRY FEED TANKS
05	BYPRODUCT HAUL ROAD
06	BYPRODUCT STORAGE SILOS
07	SLAKING WATER STORAGE TANK
08	TRAIN UNLOADING SHED
09	LIME PREPARATION BUILDING
10	BYPRODUCT RECYCLE EQUIPMENT BUILDING
11	BYPRODUCT RECYCLE DAY BINS
13	BYPRODUCT RECYCLE MAKE-UP WATER TANKS
14	BYPRODUCT RECYCLE SLURRY TANKS
16	SPRAY DRYER ABSORBERS
17	SDA FLUE GAS INLET DUCTS
18	BOOSTER FAN DISCHARGE
21	BAG HOUSES
22	BOOSTER FANS
23	COMPRESSOR / ELECTRICAL BUILDINGS
26	LIME DAY BIN
28	LIME PREPARATION AREA
29	LIME UNLOADING EQUIPMENT ROOM
30	BYPRODUCT RECYCLE AREA
31	ELEVATED BOP CONTRACTOR UTILITY RACK
32	FUTURE PROVISION SPACE FOR SCRS
33	FGD SPARE PARTS WAREHOUSE
34	BYPRODUCT HANDLING AREA
35	ACI SILOS
36	ACI ELECTRICAL BUILDINGS
37	CHI TANK
38	FLY ASH SILO
39	TRUCK SCALES
40	TRUCK SCALE HOUSE
41	BYPRODUCT TRUCK PARKING
42	LIME UNLOADING AND STORAGE AREA
43	RAIL SPUR
44	PROCESS WATER RETENTION PONDS
45	PROPOSED GRATED CONCRETE TRENCH
51	UNIT AUX. TRANSFORMER UNIT 1
52	STARTUP / STANDBY TRANSFORMER COMMON (UNITS 1&2)
53	SWITCH
54	UNIT AUX. TRANSFORMER UNIT 2
55	ELEVATED FGD CONTRACTOR UTILITY RACK
56	BOP SLEEPER RACK
57	BOP TRENCH
58	SDA PENTHOUSE ELEVATOR
59	CRANE MAINTENANCE AISLE



PRELIMINARY NOT FOR CONSTRUCTION

NORTH

GRAPHIC SCALE 60' 0 60' 120' 180'

DRAWING SCALE 1" = 60'-0"

HOLD INFORMATION		
NO.	DATE	DESCRIPTION

CONTRACTOR/INSTALLER SHALL TAKE ALL APPROPRIATE PRECAUTIONS TO ENSURE THE SAFETY OF ALL PEOPLE LOCATED ON THE WORK SITE, INCLUDING CONTRACTOR'S/INSTALLER'S PERSONNEL (OR THAT OF ITS SUB-CONTRACTOR(S)) PERFORMING THE WORK.

RELEASE INFORMATION		
REV.	DATE	DESCRIPTION

ISSUE PURPOSE: ISSUED FOR STUDY

SPECIFICATION: -

PROJECT NO.: 13138-001

I HEREBY CERTIFY THAT THIS ENGINEERING DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT PERSONAL SUPERVISION AND THAT I AM A DULY LICENSED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ARKANSAS.

ENTER NAME
ENTER DATE

MY LICENSE RENEWAL DATE IS: ENTER DATE
PAGES OR SHEETS COVERED BY THIS SEAL:
THIS DOCUMENT ONLY.

CAD FILE NAME: M-GA-001.DGN

PREPARED BY: D.J.MERRICK

REVIEWED BY: G.A.RIVERA

APPROVED BY: S.C.MCHONE

ANY MODIFICATION OR ADDITION TO THIS DRAWING BY AN ORGANIZATION OTHER THAN SARGENT & LUNDY, IS NOT THE RESPONSIBILITY OF SARGENT & LUNDY.

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WWW.SARGENTLUNDY.COM
CERTIFICATE OF AUTHORIZATION NO. 6938

Entergy

PROJECT

WHITE BLUFF STATION
UNITS 1 & 2
ENTERGY

DRAWING TITLE

GENERAL ARRANGEMENT
SDA SITE DEVELOPMENT

DRAWING NUMBER	REVISION
M-GA-001	N/A

SHEET 1 OF 1

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ATTACHMENT 8

Entergy Basis of Contingency

WB FGD Project

Risk Register

Contingency Estimate					
Estimate Total w/o Contingency, IDC, Escalation	**$ 740,968,200**				
	P90	**P80**	**P70**	**P60**	**P50**
Risk Contingency	**$ 35,870,000**	**$ 27,220,000**	**$ 20,550,000**	**$ 16,210,000**	**$ 13,090,000**
Estimate Uncertainty Contingency	**$ 95,350,000**	**$ 66,600,000**	**$ 41,540,000**	**$ 21,330,000**	**$ (290,000)**
Unknown Risk Contingency	**$ 18,560,000**	**$ 17,380,000**	**$ 16,450,000**	**$ 15,610,000**	**$ 14,810,000**
Total Contingency	$ 149,780,000	$ 111,200,000	$ 78,540,000	$ 53,150,000	$ 27,610,000
Percentage of Total	20%	15%	11%	7%	4%
Total Estimate w/ Contingency	$ 890,748,200	$ 852,168,200	$ 819,508,200	$ 794,118,200	$ 768,578,200

Project Delivery Standard

	Estimate Characteristic			**Resulting Range**	
Estimate class	**Maturity level of project definition** **expressed as % of complete engineering**	**End usage** **typical purpose of estimate**	**Methodology** **typical estimating method**	**Estimate accuracy range** **typical variation in low & high ranges**	**Target contingency range**
Class 5	0 to 2%	Rough Order of Magnitude (ROM)	Capacity factored, parametric models, judgment, or analogy	-50 to +100%	30 to 50%
Class 4	1 to 15%	Feasibility	Equipment factored or parametric models	-30 to +50%	25 to 40%
Class 3	10 to 50%	Funding Authorization	Semi-detailed unit costs with assembly level line items	-20 to +30%	15 to 30%
Class 2	30 to 90%	Control	Detailed unit costs with forced detailed take-off	-15 to +20%	5 to 20%
Class 1	50 to 100%	Check Estimate	Detailed unit cost with detailed take-off	-10 to +15%	2 to 7%

WB FGD Project
Risk Register

ESTIMATE UNCERTAINTY								
		Quantitative Risk Analysis						
Risk Category	**Description of Risk**	**Estimate Total w/out Contingency**	**Min ($)**	**Expected**	**Max ($)**	**QRA Comments**	**Status / Comments**
Estimate Uncertainty	**EPC Contract**	$ 752,912,300	($188,228,075)	$0	$188,228,075	From S&L estimate report, the project definition and accuracy of the individual components in this estimate result in an overall accuracy of +/- 25%.	
Estimate Uncertainty	**Owner's Costs**	$ 58,546,000	($11,709,200)	$0	$17,563,800	Estimate from Entergy, estimate is considered a Class 3 (+30% to -20%).	Entergy Indirects were calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.
Estimate Uncertainty	**Third Party Services**	$ 12,544,000	($3,136,000)	$0	$3,136,000	From S&L estimate report, estimate is considered a Class 3 (+25% to -25%)	

WB FGD Project
Risk Register

UNKNOWN RISK							
		Quantitative Risk Analysis					
Risk Category	Description of Risk	Estimate Total w/out Contingency	Min ($)	Expected	Max ($)	QRA Comments	Status / Comments
Unknown Risks	**UNKNOWN RISKS:** This is part of the calculation for the overall contingency to include in the project budget.	$ 740,968,200	$ 7,409,682	$ 14,819,364	$ 22,229,046	Estimating standard guidance. Min = 1%, Exp = 2%, Max = 3%	Due to lack of historical data and current project development, there are a range of potential impacts from unknown risks not yet captured in the estimate uncertainty and identified risks, Entergy contingency guidance is to use 1% - 3% of the total estimate without contingency. This item can be captured in the risk register and modeled with the identified risks when estimating contingency.

IDENTIFIED RISKS

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-007	Budget	**PROJECT BUDGET - CRAFT LABOR - PER DIEM RATE RISK:** This risk is related to the required craft labor per diem increasing due to the high demand of craft labor, at a percentage greater than the estimated rate.	ALL	3	2	0	0	**6**	Low	An increase to per diem to attract labor will increase the project total estimate.	45%	$0	$0	$4,290,000	Yes	The estimated Per Diem is $13M. Assume a 33% increase as a max.	
2014-002	Budget	**PROJECT BUDGET - CRAFT LABOR - WAGE RATE ESCALATION:** This risk is related to wage rates rising, at a rate greater than the rate used in the estimate, due to the high demand for craft labor.	ALL	3	3	0	0	**9**	Low	Received rates over 10-year period from S&L. Range has fluctuated from 0% to 21.23% during that period. Current economic conditions indicate a high probability of craft labor rates increasing beyond the current projection of 3.35% provided by S&L.	45%	($19,700,000)	$0	$42,300,000	Yes	Received rates over 10-year period from S&L. Looked at range and average high and low rates. Expected escalation rate is 3.35%. Assumed Min rate of 1.675% and Max rate of 6.7%. Results in potential increase of $42.3M over current escalation estimate and potential decrease of $19.7M.	
2014-001	Budget	**PROJECT BUDGET - IDC:** This risk is related to the cost of capital increasing over the life of the project, at a rate different than the current estimated escalation rate.	ALL	1	5	0	2	**7**	Low	The EPA Cost Control Manual uses a rate of 7% which was used for the estimate. Historical EAI AFUDC rates have been under 7%.	5%	$0	$0	$25,000,000	Yes	Assumes an index rate of 7.5%; this results in an increase of ~$25M over current IDC estimate.	
2014-006	Budget	**PROJECT BUDGET - CAPITAL SUSPENSE ADJUSTMENTS:** The risk is related to Capital Suspense increasing over the life of the project from the current Entergy forecasted rate.	ALL	2	3	1	1	**10**	Low	Adjustment of rates impact the project total estimate.	25%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-005	Budget	**PROJECT BUDGET - EPC MATERIAL ESCALATION:** Project material cost may be subject to escalation	ALL	1	3	0	1	**4**	Low	Material escalation is included in the project estimate.	5%	$0	$0	$0	No	Material escalation is included in the project estimate. The estimate uncertainty addresses the risk of the amount of material and the material escalation rate being different than the current forecasted rates.	
2014-003	Budget	**PROJECT BUDGET - LIME ESCALATION:** Project lime cost may be subject to escalation different than the estimated rate.	ALL	3	1	0	0	**3**	Low	Assume that lime escalation rate will increase during project.	45%	$0	$0	$0	No	Budgeted Lime escalation rate is 2.15%. The estimate uncertainty addresses the risk of the amount of material and the escalation rate being different than the current forecasted escalation rate.	
2014-005	Budget	**PROJECT BUDGET - MATERIAL LOADER ADJUSTMENTS:** The risk is related to the material loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	1	0	0	**4**	Low	Probability that Material Loaders will change over life of the project.	20%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the internal loaders estimate.	
2014-004	Budget	**PROJECT BUDGET - PAYROLL LOADER ADJUSTMENTS:** The risk is related to the payroll loaders increasing over the life of the project from the current Entergy forecasted loaders.	ALL	4	2	0	0	**8**	Low	Probability that Payroll Loaders will change over the life of the project.	70%	$0	$0	$0	No	Entergy Indirects will be calculated utilizing the Entergy FVET tool. The risk associated with the individual rates will be included in the estimate uncertainty of the Entergy Payroll estimate.	
2014-006	Budget	**SALES TAX:** Risk that the sales tax rate will change and add additional costs to the project.	ALL	2	1	0	0	**2**	Low	Probability that the Sales Tax will change order the life of the project.	20%	$0	$0	$0	No	The risk associated with a Sales Tax change will be included in the estimate uncertainty, which also includes the risk of the quantity of materials subject to sales tax.	

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-010	Eng	**DESIGN CRITERIA:** Design criteria is missing information, or information is incorrect resulting in changes to the technical specifications and requirements during the project. The risk would result in re-engineering / re-work.	ALL	2	3	3	1	**14**	Medium Low	The Owner's Engineer (S&L) has performed Engineering Studies in 2009 and 2013. The revised Design Criteria document reflects the current project requirements.	20%	$0	$5,000,000	$25,000,000	Yes	Assumption that the design criteria accurately reflects the requirements of the project, any corrections will have minimal impact to detailed design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-011	Eng	**ENGINEERING SUPPORT:** Inadequate support to review EPC contractor's design to ensure it meets Entergy requirements. The risk would result in re-engineering / re-work.	ALL	1	3	3	2	**8**	Low	The Project will use an Owner's Engineer to augment staff requirements to mitigate this risk. This risk is the potential for redesign based on inadequate reviews.	5%	$0	$5,000,000	$25,000,000	Yes	Assumption that there will be minimal rework based on inadequate Entergy review of EPC contractor design. Min is 0%, Expected is 1%, Max is 5% of EPC Direct Costs $500M.	
2014-012	Eng	**SCOPE GAP OR CHANGES:** Work scope not defined in EPC contract, and not identified/unforeseen conditions in project budget. Risk would result in additional scope to EPC contract.	ALL	2	4	3	2	**18**	Medium Low	Low probability due to 2009 and 2013 studies. BOP scope not as defined as FGD island. There is only minimal engineering complete at this stage. Also, risk covers the potential for additional design requirements over base FGD design to meet Entergy standard designs.	20%	$5,000,000	$15,000,000	$45,000,000	Yes	Assumption that any missed scope will not be significant, there is an Open Book period for development. Assume minimum of 1% of the $500M FGD direct costs, 3% expected, 9% max.	
2014-013	Eng	**TECHNOLOGY - BAGHOUSE**: The baghouse on each of the units fails to meet the PM emissions limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	
2014-014	Eng	**TECHNOLOGY - Dry FGD**: The selection of the technology to meet the emission limits with margin is insufficient to meet the required limits.	ALL	1	3	5	5	**13**	Medium Low	Low probability due to proven technologies will be specified, and EPC contract will have vendor guarantees.	5%	$0	$0	$0	No	Not included in QRA. Final payment of EPC contract will be based on successful demonstration of performance.	

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-015	Env	**AIR PERMIT (AR) - DELAY**: Delay in receiving the permit, for an additional 6 months (24 total).	ALL	1	2	3	3	**8**	Low	Cost impact to expedite project to stay on schedule as a result in the delay. The current timeline of 18 months accounts for some expected delay.	5%	$0	$0	$3,000,000	Yes	Assume $500k/month for up to 6 mo of delay. This would be prior to FNTP.	In the current timeline, there is some schedule float that could be used. Entergy could release FNTP prior to receipt of the air permit.
2014-016	Env	**ASH DISPOSAL:** EPA determines that combustion byproducts are a hazardous waste resulting in need to utilize other material to stabilize scrubber byproduct.	ALL	1	1	0	3	**4**	Low	Cost impact: possible HAZMAT training and treatment of ash. Still would landfill on site. Loss of ash sales.	5%	$0	$0	$150,000	Yes	Assume some additional training, and minimal equipment modifications.	Most ash will be collected in the ESP. This risk would be addressed by a separate project.
2014-018	Env	**COMPLIANCE RULE - Vacated or Delayed:** If the rule is vacated or delayed, what is the impact?	ALL	1	2	0	0	**2**	Low	Assume delay prior to project approval but same compliance period to comply. Cost impact: engineering, payroll, AFUDC during delay period.	5%	$0	$0	$3,000,000	Yes	Project delayed prior to LNTP. Assume $500k/month for 6 months.	
2014-017	Env	**ASH DISPOSAL:** The ADEQ might impose the same permit restriction as it did at the Flint Creek Plant and not allow WB to route landfill leachate directly to the surge pond.	ALL	3	0	0	1	**3**	Low	Project will not increase probablility to occurrence; plant O&M risk. Cost impact: treatment of leachate prior to sending to surge pond.	45%	$0	$0	$0	No	Plant O&M risk.	
2014-019	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB1	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$4,000,000	$16,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-8 mo delay at $2M/month. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-021	EPC	**Delay in FNTP:** Delay in Entergy issuing FNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in issuing FNTP. Delays for receipt of the air permit or regulatory approval are separately identified risks.	20%	$0	$3,000,000	$6,000,000	Yes	Assume EPC contractor request compensation for the FNTP delay (equipment contracts, etc). ($1M/month delay)	
2014-022	EPC	**Delay in LNTP:** Delay in Entergy issuing LNTP	ALL	2	2	2	3	**14**	Medium Low	Delay in receiving internal approvals.	20%	$0	$1,500,000	$3,000,000	Yes	Assume EPC contractor request compensation for the LNTP delay (equipment contracts, etc). ($0.5M/month delay)	
2014-023	EPC	**EPC CONTRACT EQUIPMENT VALUE:** Equipment estimate uncertainty during the period from when the contract price is developed to the LNTP.	ALL	2	4	0	1	**10**	Low	The time between the Open Book Period and LNTP is approximately 14 months.	20%	$0	$8,000,000	$20,000,000	Yes	Risk of price changes for $400M of the EPC contract, subject to 14 months between negotiation and award. Min = 0%, Exp = 2%, Max = 5%	
2014-024	EPC	**EPC CONTRACT:** Negotiated EPC fee	ALL	2	4	0	2	**12**	Medium Low	EPC Fee assumed to be in the 8%-15% range.	20%	($12,000,000)	$0	$12,000,000	Yes	Estimate includes a 10% fee or ~$60M. Min = 8% fee, Max = 12% fee.	
2014-069	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (EPC procurement costs)	ALL	1	1	1	3	**5**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$7,500,000	Yes	Estimate of EPC procurement costs, negotiating, and potential incrase on contract value. To account for procurement activities, Max 1% of EPC value	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-070	EPC	**EPC CREDIT RISK:** EPC contractor default on contractor (schedule delay)	ALL	1	5	5	5	**15**	Low	Entergy will work with qualified vendors that have had a credit risk review.	5%	$0	$0	$36,000,000	Yes	Default of the EPC contractor would result in delay of project to procure and onboard a new contractor. For this calculation, the EPC contractor is assumed to default during construction. Apply amount of IDC ($4M/mo) plus carrying costs of Entergy costs ($500k/mo) at this date through end of project to the expected delays (max: 8 mo).	
2014-032	EPC	**SCHEDULE - Delayed:** Change in project schedule due to longer compliance timeline.	ALL	1	1	1	1	**3**	Low	Assume that, if compliance date is delayed, then all costs will shift accordingly. Incremental costs would be maintaining internal staff in the interim, IDC.	5%	$0	$0	$12,000,000	Yes	Assume delay would be known before contract award, when the FIP or SIP is issued. Delay of min = 0 mo, exp = 0 mo, max = 24 mo @ $500k/mo	
2014-033	EPC	**SCHEDULE - Shorter Compliance Timeline:** Change in project schedule that shortens compliance timeline.	ALL	1	4	0	3	**7**	Low	Assume that labor costs and costs to expidite equipment would increase to comply with earlier timeline.	5%	$0	$0	$30,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less IDC costs. Assume 15% increase of estimated craft labor of ~$200M.	
2014-035	EPC	**UN-IDENTIFIED UNDERGROUND OBSTRUCTION:** Claims for extra work for un-identified underground pipe, etc.	ALL	2	3	2	2	**14**	Medium Low	Project plans to perform exploration work to identify unknown underground obstructions during the Open Book period. This risk if realized will increase the EPC contract price.	20%	$0	$500,000	$3,000,000	Yes	Assumption that any missed scope will not be significant. Schedule delays of $500k/month.	

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-036	EPC	**WEATHER-RELATED DELAYS:** Extreme weather can greatly affect craft productivity and result in partial or complete site shutdown. Such weather conditions can increase the risk and provide the basis for a contractor claim for a change order.	ALL	1	1	3	2	**6**	Low	The project is subject to extreme weather events. This risk will be further developed during the Open Book period.	5%	$0	$4,000,000	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month. Assumption that the current schedule has sufficient float to mitigate this risk. The Open Book period will be used to develop a more detailed schedule.	The project execution plan is to perform a majority of the construction prior to any outage. Weather risks will be assigned to the EPC contractor.
2014-020	EPC	**CONSTRUCTION DELAYS:** Construction delays could negatively affect the project and ability to meet a compliance date target. It includes the following contractor identified risks: 1) Damage or late delivery of equipment and materials 2) Weather impact to craft productivity and full or partial site shutdown 3) Craft productivity 4) Labor availability of pipefitters, welders, and electricians	WB2	2	2	3	2	**14**	Medium Low	The contracting strategy will use schedule incentives to maintain the schedule. The labor availability risk will be shared with the contractor, craft labor escalation is a separate risk item.	20%	$0	$0	$0	No	Risk QRA combined with EPC Construction Delays for WB1. Current schedule reflects adequate available time for the EPC contractor to account for these delays. Escalation is a separate risk.	Identified risks will be assigned to the EPC contractor.
2014-008	EPC	**LABOR:** Schedule delays due to union labor disputes.	ALL	1	2	2	2	**6**	Low	Using non-union labor.	5%	$0	$0	$0	No	Using non-union labor.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-027	EPC	**OPEN BOOK PERIOD**: Change in contract terms (Limitiation of Liability) during EPC contract negotiations.	ALL	1	3	0	1	**4**	Low	The RFP process to select the EPC contractor will require the contractor to state required terms for an EPC contractor prior to their selection. The Open Book period should not increase their project risk profile, which would be a driver for a change in their terms.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-028	EPC	**OPEN BOOK PERIOD**: Change in rates from EPC contractor during open book period.	ALL	1	1	0	1	**2**	Low	The EPC contractor's labor and equipment rates will be negotiated during the Open Book period to develop the contract price.	5%	$0	$0	$0	No	Not included in QRA. Project estimate includes estimate uncertainty for this risk.	
2014-029	EPC	**OPEN BOOK PERIOD**: Unable to negotiate a fixed price contract.	ALL	1	0	0	0	**0**	Low	The scope and schedule of this project are sufficient to meet the project goals. There is no indication that this risk is probable.	5%	$0	$0	$0	No	Not included in QRA.	
2014-030	EPC	**POOR PERFORMANCE BY CONTRACTOR ON PROJECT:** Risk of claims and change orders increases if contractor expects and/or experiences loss on the project.	ALL	1	1	2	1	**4**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy. Risk is for total claims greater than the amount of contingency.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-031	EPC	**POOR QUALITY OF CONTRACTOR WORK**: Schedule impact due to rework and adverse affect on long-term plant operation.	ALL	1	1	2	1	**4**	Low	EPC bidders will be selected based on Entergy experience and previous work experience.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-034	EPC	**SCOPE OR DESIGN PROBLEMS:** Poor scope, technical design, or unclear technical requirements could result in change orders with added cost and/or schedule delay or an end product that does meet customer needs	ALL	3	3	3	2	**24**	Medium Low	Complicated project with many interfaces to exisitng facility. Assume multiple small change orders.	45%	$0	$0	$0	No	Not included in QRA. This risk is similar to Engineering risks. Project estimate includes estimate uncertainty for this risk.	
2014-037	EPC	**POOR PERFORMANCE:** Contractor does not meet schedule or performance requirements.	ALL	2	1	2	1	**8**	Low	Risk exists for contractor claims, project controls will be in-place to support Entergy.	20%	$0	$0	$12,000,000	Yes	These delay estimates represent Owner's costs due to the delay (AFUDC, labor) 0-6 mo delay at $2M/month.	
2014-038	Goal	**COMPLIANCE - NON-COMPLIANCE**: The new emission standards cannot be met by the units.	ALL	1	5	5	5	**15**	Medium Low	Industry information shows that the emission compliance levels can be met with the available tecnologies.	5%	$0	$0	$0	No	Cost estimate is beyond project value.	
2014-053	Ops	**LONG TERM OPERATION - CAPACITY:** Unit derate or capacity restriction resulting from control technologies.	ALL	1	1	1	1	**3**	Low	Unit capacity will be affected by this project. It will be defined and a guarantee will be negotiated with the EPC contractor.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine capacity impact of project.
2014-054	Ops	**LONG TERM OPERATION - INCREASED O&M:** Increases to the unit's O&M due to control technology.	ALL	1	1	1	1	**3**	Low	Additional O&M will be required by this project. It will be defined when the technology is selected during the Open Book period.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-055	Ops	**LONG TERM OPERATION - OPERATOR INTERFACE:** An increase in training requirements due to control technology.	ALL	1	1	1	1	**3**	Low	Additional Operator interface will be required by this project.	5%	$0	$0	$0	No	Not a project risk.	Additional Operations staff is included in the project estimate. Review this risk after Open Book Period to determine impact of project.

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-056	Ops	**LONG TERM OPERATION - RELIABILITY:** Impacts to the unit's reliability.	ALL	1	1	1	1	**3**	Low	The EPC contract will require equipment guarantees and system redundancy to provide reliability.	5%	$0	$0	$0	No	Not a project risk.	Review this risk after Open Book Period to determine O&M impact of project.
2014-057	Permiting	**Department of Transportation:** Impact of schedule delay due to permitting the road modification.	ALL	1	1	1	0	**2**	Low	Unable to determine risk until Open Book Period to understand permit time required and date when road modification must be in place.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	Review this risk after Open Book Period to determine O&M impact of project.
2014-058	Permitting	**REGULATION CHANGE:** Change in future regulation to lower emission limits or 30-day rolling average.	ALL	1	1	0	0	**1**	Low	Need additional information, this would be a future project. Technology for FGD has not been determined	5%	$0	$0	$0	No	Risk will be mitigated during technology selection.	
2014-040	PM	**INTERNAL APPROVALS:** Possible delays due to delay of internal approval of contracts	ALL	2	1	1	2	**8**	Low	Risk exists with the challenges of obtaining internal approvals.	20%	$0	$0	$1,500,000	Yes	Assume internal project team continues to support Board approval during the regulatory and permitting periods. (Assume $500k/mo).	
2014-041	PM	**ISSUE RESOLUTION:** Possible schedule delays due to non-resolution of issues as they arise.	ALL	2	2	3	2	**14**	Medium Low	Risk exists for undefined issues.	20%	$4,500,000	$9,000,000	$13,500,000	Yes	Undefined issues may impact schedule & project scope. (Assume AFUDC ($4M) + Owner's costs ($500k) per month) Min = 1 mo, expected = 2 mo, max = 3 mo)	
2014-039	PM	**COMMUNICATIONS:** Possible schedule delays and costs increases due to poor communication between all parties	ALL	1	1	2	2	**5**	Low	Risk exists for contractor claims. The contracting strategy using only one EPC contractor should minimize this risk.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $. Adequate staffing of project is a separate risk.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING							Quantitative Risk Analysis						Status / Comments
				Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	
2014-042	PM	**MANAGEMENT - INSUFFICIENT INTERNAL PROJECT STAFF:** Insufficient Internal project resources - unable to meet schedule. Project costs increase.	ALL	2	2	0	2	**8**	Low	Internal labor costs would be higher than budgeted.	20%	$0	$0	$0	No	Project will plan to use outside contractors to staff project.	
2014-043	PM	**MANAGEMENT - PRUDENCY DETERMINATION:** The project team is unable to justify and document project decisions and the related costs to defend decisions as prudent in future rate cases. Mitigation includes processes for contemporaneous documentation.	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-044	PM	**PROJECT CONTROLS:** Project has insufficient project controls / oversight / documentation to manage and control cost.	ALL	1	3	0	4	**7**	Low	Stage Gate process requires project controls. Generic project costs would be higher than budgeted.	5%	$0	$0	$0	No	Additional staff included in the project estimate to cover PEI oversight of project.	
2014-045	PM	**RECORDS MANAGEMENT:** Document control is insufficient leading to inability to support Regulatory Recovery	ALL	1	1	1	3	**5**	Low	The project will follow project delivery standards, risk should be minimal.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-048	PM	**SCOPE CHANGES:** Possible delays or increased cost due to improperly managed project scope changes.	ALL	1	2	2	2	**6**	Low	Potential delays due to internal decisions in a timely manner.	5%	$0	$0	$0	No	Not included in QRA. Missed scope part of the Engineering risks.	

WB FGD Project
Risk Register

Risk ID	Risk Category	Description of Risk	Unit	SCORING: Prob. Rating & History	Cost Impact Rating	Schedule Impact Rating	Other Impact Rating	Total Risk Score	Risk Rating	Justification of Ratings	Quantitative Risk Analysis: Probability	Min ($)	Expected	Max ($)	Include in QRA	QRA Comments	Status / Comments
2014-059	Reg	**REGULATORY - DELAY:** Regulatory delays could negatively affect the project schedule. The expected duration is estimated to be 18 months.	ALL	2	2	5	4	**22**	Medium Low	Project schedule assumes 18 mo to receive approval. If additional time is required, Entergy may choose to issue FNTP prior to receipt to avoid potential costs.	20%	$0	$0	$3,000,000	Yes	Assumption that current schedule has some float, add $ for premium time, less AFUDC costs. ($0.5M/month delay)	
2014-068	Schedule	**SCHEDULE - FORCE MAJEURE** - Increase in cost of project due to force majeure	ALL	1	1	1	1	**3**	Low	BAR insurance will be in place.	5%	$0	$0	$10,000,000	Yes	Insurance deductible is expected to be structured similar to other projects. $500,000 deductible for flood, 5% of insured value for Named Windstorm with min of $1,000,000 and max of $10,000,000.	
2014-062	Schedule	**COMPLIANCE - DEADLINE**: Risk that the project will not meet the deadline?	ALL	1	3	4	3	**10**	Low	Current timeline has sufficient time to develop project.	5%	$0	$0	$0	No	Current schedule reflects adequate available time to complete the project. EPC contract will include schedule requirements.	
2014-063	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB1	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-064	Schedule	**OUTAGE SCHEDULE:** Outage schedule moves from current schedule dates.	WB2	2	1	1	1	**6**	Low	Project expects the current scheduled outages to move to meet project requirements.	20%	$0	$0	$0	No	Schedule flexibility is expected.	
2014-066	Schedule	**SCHEDULE INSUFFICIENT:** EPC Contractor does not provide schedule with sufficient level of detail to coordinate activities	ALL	1	1	1	1	**3**	Low	EPC contract will require detailed project schedule. Entergy project controls will be in-place to support schedule development and maintenance.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	
2014-067	Supply Chain	**LIME AVAILABILITY:** Will the required lime for the long term operation be available?	ALL	1	1	1	1	**3**	Low	S&L study did not identify lime availability concerns.	5%	$0	$0	$0	No	Insufficient information to provide QRA risk $.	

Probability and Impact Definition

Probability Rating	Probability Definition (Likelihood of Occurrence)	Discreet Value for QRA
1	Less than or equal to 10 % Probability of Occurrence	5%
2	Greater than 10% but less that 30 % Probability of Occurrence	20%
3	Greater than 30% but less that 60 % Probability of Occurrence	45%
4	Greater than 60% but less that 80 % Probability of Occurrence	70%
5	Greater than 80% Probability of Occurrence	90%

Cost Impact Rating	Cost Impact Value (Impact to Entergy Cost only) (Project Cost = $500M)	Min Cost Impact (QRA)	Most Likely Cost Impact (QRA)	Max Cost Impact (QRA)
1	(<0.5% of project cost)	$ 100,000	$ 1,000,000	$ 2,500,000
2	(0.5% - 1.4% of project cost)	$ 2,500,000	$ 4,750,000	$ 7,000,000
3	(1.5% - 2.9% of project cost)	$ 7,000,000	$ 11,000,000	$ 15,000,000
4	(3% - 4.9% of project cost)	$ 15,000,000	$ 20,000,000	$ 25,000,000
5	(>5% of project cost)	$ 25,000,000	$ 37,500,000	$ 50,000,000

Schedule Impact Rating	Schedule Impact Value (Impact to Affected Summary Activity)	Min Schedule Impact (QRA)	Most Likely Schedule Impact (QRA)	Max Schedule Impact (QRA)
1	Less than 30 days	0	15	30
2	Between 30 and 60 Calendar days	30	45	60
3	Between 60 and 90 Calendar days	60	75	90
4	Between 90 and 150 calendar days	90	120	150
5	Between 150 and 210 calendar days	150	180	210

Other Impact Rating	Other Effect on Project (Regulatory/Legal, Safety, Company Reputation and Quality) - more details below
1	No impact
2	Minimal Impact
3	Moderate Impact
4	Significant Impact
5	Severe Impact

Other Impact Value	IMPACT (Effect on Project)
1	Has no impact on (**Company Reputation**)
	Has no impact on quality (**Quality**)
	Not likely to result in injury or illness (**Safety**)
	No impact on timely CPCN or full cost recovery (**Regulatory/Legal**)
2	Has limited impact on (**Company Reputation**)
	Quality issue has minimal impact on project (**Quality**)
	Has a direct, minor impact on a near miss driver, an OSHA RA driver, or human error mechanism. Is an emerging
	CPCN delayed by less than 1 month and/or cost disallowance up to $7,500,000 (**Regulatory/Legal**)
3	Has moderate impact on (**Company Reputation**)
	Quality issue affects work activities and requires application of the corrective action program (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. An emerging safety issue where a
	CPCN delayed between 1-3 months and/or cost disallowance between $7,500,000 and $12,500,000
4	Has significant impact on (**Company Reputation**)
	Quality issue requires immediate management attention (**Quality**)
	Will create a near miss driver, an OSHA RA driver, or human error mechanism. No workaround is present.
	CPCN delayed between 3-5 months and/or cost disallowance between $12,500,000 and $20,000,000
5	Has severe impact on (**Company Reputation**)
	Quality issue requires work stoppage (**Quality**)
	Likely to cause one or more deaths (**Safety**)
	CPCN delayed more than 5 months and/or cost disallowance greater than $20,000,000 (**Regulatory/Legal**)

* The Project manager should establish clear thresholds for financial impact at the outset of the project. These should be articulated in the Project Execution Plan and be approved in accordance with the provisions of the Project Management Manual.

REGIONAL HAZE MODELING ASSESSMENT REPORT

Entergy Arkansas, Inc. > Independence Plant

Entergy®
THE POWER OF PEOPLE℠

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August 4, 2015

Project 154401.0074

Trinity Consultants

Environmental solutions delivered uncommonly well

Exhibit C to EAI Comments

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1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published a proposed Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. Within the proposed Arkansas FIP, the EPA addressed the portions of the Arkansas State Implementation Plan (SIP) that the EPA disapproved in its final action, published March 12, 2012.[1] In addition to addressing the control requirements for Arkansas sources determined to be subject to Best Available Retrofit Technology (BART), the EPA also addresses the Reasonable Progress Goals (RPGs) for Class I areas in Arkansas and reasonable progress control requirements to achieve these RPGs. Specifically, the EPA proposed to meet RPGs by presenting two options for controlling emissions from the Entergy Arkansas, Inc. (Entergy) Independence Plant, which is not subject to BART.

In order to assess the reasonableness of the proposed control options for Electric Generating Units (EGUs) 1 and 2 at the Entergy Independence Plant (Independence units), as well as the EGUs at Entergy's White Bluff Plant (White Bluff units), the Comprehensive Air Quality Model with Extensions (CAMx) was used to perform regional haze modeling. This analysis was based on the CAMx regional haze modeling originally performed by the Central Regional Air Planning Association (CENRAP).

This report has been prepared to describe the modeling methodology used to evaluate Entergy's proposed control measures for emissions of sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) from the Independence and White Bluff units, as alternatives to the EPA's proposed control options. Entergy proposes a comprehensive approach to regional haze, involving the installation of low NO_X burners (LNB) and separated overfire air (SOFA) and a reduction in permitted SO_2 emission rates for the Independence units and White Bluff units, and the cessation of coal combustion at White Bluff by 2028. In addition to Entergy's proposed control scenario, the controls proposed in the Arkansas FIP were also evaluated using CAMx so that the expected visibility improvements from each scenario could be compared to EPA's proposed controls. The modeling methodology was developed in accordance with the original CENRAP modeling and takes into account Arkansas's two Class I areas, the Caney Creek Wilderness Area (Caney Creek) and the Upper Buffalo Wilderness Area (Upper Buffalo).

[1] Environmental Protection Agency. Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Federal Register Volume 77, Number 48. March 12, 2012.

2. REGIONAL HAZE MODELING METHODOLOGY

The regional haze assessment involves the determination of the total light extinction, the contribution of each selected emissions source to the total light extinction, and an analysis of the uniform rate of progress (URP) curves for Caney Creek and Upper Buffalo. This regional haze modeling analysis was performed using the advanced photochemical modeling software CAMx. The CAMx modeling system is a publicly available computer modeling system for the integrated assessment of photochemical and particulate air pollution. A description of the modeling files, domain, model simulation steps, and analysis methodologies are discussed in detail in the following subsections.

2.1. EPA PHOTOCHEMICAL MODELING PLATFORM

This analysis builds on the modeling of 2002 and 2018 emissions conducted previously by CENRAP and subsequently updated by ENVIRON for the EPA to aid in the development of the EPA's proposed Oklahoma and Texas Regional Haze FIP.[2] ENVIRON's 2018 baseline scenario is based on input data originally developed by CENRAP and enhanced by ENVIRON to provide higher resolution results and to accommodate more recent versions of CAMx and associated pre-processors. 2018 emissions data used in this baseline scenario were projected with growth and control factors from the 2002 emissions data obtained from the 2002 National Emissions Inventory (NEI).[3]

2.1.1. Modeling Domain

Figure 2-1 below presents the modeling domain used in the CENRAP regional haze assessment. This nested grid configuration of the CAMx domain includes the following grids:

- RPO_36km: This grid contains 36 kilometer (km) grid cells covering all of the continental U.S., along with southern Canada, northern Mexico, and portions of the Gulf of Mexico, Atlantic Ocean, and Pacific Ocean.
- Regional_12km: This nested grid contains 12 km grid cells covering all of Texas, Arkansas, and Louisiana, a majority of Oklahoma, and parts of Mississippi, Tennessee, Missouri, and New Mexico.

All modeling domain grids are projected in the Lambert Conformal Conic (LCC) map projection. The 36 km grid is also the domain used by the Regional Planning Organizations (RPOs) of which CENRAP is an example. The 12 km grid was developed by ENVIRON to allow for minimizing the effects of the boundary conditions on the 12 km grid since the boundary condition information is passed from the 36 km to the 12 km grid. The modeling domain contains locations of Interagency Monitoring of Protected Visual Environments (IMPROVE) sites which correspond to the Arkansas Class I areas, Caney Creek and Upper Buffalo, which are under consideration in the assessment of RPGs in the Arkansas FIP.

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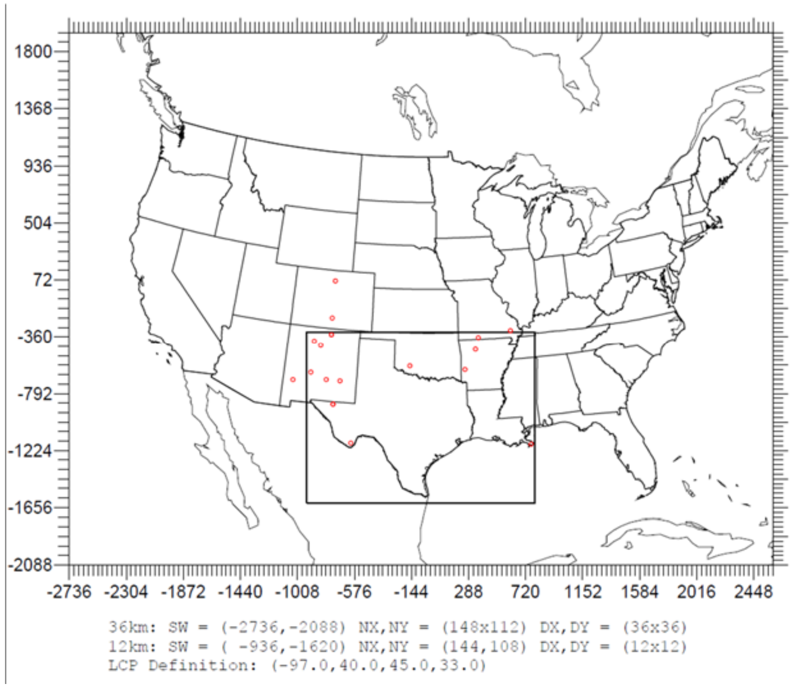
[2] Snyder, Erik, Michael Feldman, and Joe Kordzi. "Technical Support Document for the Oklahoma and Texas Regional Haze Federal Implementation Plans." U.S. EPA. November 2014.

[3] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

Figure 2-1. EPA and ENVIRON Photochemical Modeling Platform Domain[4]



2.1.2. Emissions Inventory

The CAMx model requires emissions in an hourly, speciated format. The Sparse Matrix Operator Kernel Emissions (SMOKE) pre-processor is used to process emissions data of various types of regional haze precursor emissions into a temporally and spatially allocated format. The SMOKE emissions pre-processor was configured to match the EPA's specifications and then used to process the emissions inventories used in this assessment. Version 3.1 of SMOKE was utilized in this analysis to be consistent with the EPA. The 2018 baseline scenario emissions data was used as the basis for this analysis. Each of the modeling scenarios required specific updates to the Arkansas FIP selected sources; therefore, these emissions points were updated in inventories separately from the other point source inventories and were merged into a single CAMx inventory file once SMOKE processing was complete.

2.1.3. Other CAMx Input Data

The remaining input data required to run CAMx, including but not limited to meteorological data, land-use files, albedo-haze-ozone inputs, photolysis rates, boundary and initial conditions, were unchanged from the original 2018 baseline scenario files.[5]

[4] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

[5] Nopmongcol, Uarporn and Greg Yarwood. Memo to Ellen Belk, EPA Region 6. "2002 Baseline CAMx Simulation, Texas Regional Haze Evaluation." February 21, 2013.

2.2. ENTERGY SCENARIO ONE – BASELINE SCENARIO

The purpose of the baseline scenario is to develop a baseline level of total modeled light extinction at Caney Creek and Upper Buffalo. Additionally, the CAMx Particulate Source Apportionment Tool (PSAT) was used to trace the specific impacts of the Independence and White Bluff units as well as the remaining Arkansas sources subject to BART. In this way, the uncontrolled contribution of each source could be determined. As additional modeling is performed, the contributions of equipment from each scenario can be compared against the baseline contributions to determine the relative improvement or deterioration in visibility that can be expected due to application of various control options.

2.2.1. Emissions Inventory Updates

This regional haze assessment was based on the 2018 baseline scenario performed by ENVIRON. ENVIRON obtained the 2018 emissions inventory developed by CENRAP and incorporated selected updates, including but not limited to the addition of several new units and one new facility, the removal of several shutdown units, and the update of emission rates due to recently installed controls on selected units. Additionally, ENVIRON incorporated updates specific to the Oklahoma and Texas FIP determinations.[6]

It was noted during Entergy's initial review of these emissions inventories that two of the Arkansas sources subject to BART were not present. These two sources were the Entergy Lake Catherine Unit 4 (Lake Catherine unit) and the Arkansas Electric Cooperative Corporation (AECC) Carl E. Bailey Generating Station Unit 1 (Bailey Station unit). It is believed that the growth and control factors originally used by CENRAP to project the 2018 emissions inventory may be responsible for the proposed removal of the Bailey Station unit while the Lake Catherine unit appears to have been excluded from the original CENRAP modeling. Therefore, these two units were added into the emissions inventory for Entergy's baseline scenario.

Further review of the CENRAP inventories also indicated that the stack parameters for some of the Arkansas sources subject to BART were no longer representative of actual operations. The geographic coordinates of several sources, including the Independence and White Bluff units, were likewise found to point to inaccurate locations. The stack parameters and source locations of the Arkansas sources subject to BART were therefore updated to more accurately represent the current stack characteristics.

Additionally, since the growth and control factors estimated controlled emission rate values for the Arkansas FIP selected sources, it was necessary to revise the emission rates of these sources with uncontrolled values. The Arkansas sources subject to BART, excluding the White Bluff units, were given emission rates equal to the pre-controlled values based on the 2002 NEI data. The five selected Entergy units (from the Independence Plant, the White Bluff Plant, and the Lake Catherine Plant) were updated with revised emission rates provided by Entergy representing the uncontrolled actual emissions.

A table summarizing the emission rates of the Entergy units modeled in each scenario is included in Appendix A.

2.3. ENTERGY SCENARIO TWO – ENTERGY'S PROPOSED CONTROL APPROACH

With this modeling scenario, Entergy intends to determine the expected visibility benefits of the proposed alternative to the Arkansas FIP's determinations. As discussed in earlier sections, the proposed alternative scenario includes the installation of interim controls (e.g., LNB/SOFA) on the Independence and White Bluff

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[6] Nopmongcol, Uarporn, et al. Memo to Ellen Belk, EPA Region 6. "2018 Base Case CAMx Simulation, Texas Regional Haze Evaluation." September 16, 2013.

units, the reduction of SO_2 emissions, and the ultimate cessation of coal combustion at the White Bluff facility. For the purposes of this assessment, control efficiencies were applied to the NO_X and SO_2 emissions rates for the Independence units while all White Bluff emissions sources were removed from the emissions inventories to signify the cessation of coal combustion.

2.3.1. Emissions Inventory Updates

Entergy's baseline scenario (Scenario One) served as the basis for Entergy's Proposed Scenario. Specific emissions inventory updates include the removal of all White Bluff Plant point sources from the emissions inventories and the revision of the emission rates of Entergy's Independence units and the Arkansas sources subject to BART. The Arkansas BART sources were modeled with the proposed post-control emission rates identified in the Arkansas FIP while the Independence units were modeled with the limited control efficiencies proposed by Entergy.

2.4. ENTERGY SCENARIO THREE – PROPOSED ARKANSAS FIP SCENARIO

The purpose of the Proposed Arkansas FIP Scenario is to determine the projected regional haze impacts of applying the controls proposed to be required by the Arkansas FIP. Therefore, all Arkansas sources determined to be subject to BART and the Independence units were modeled with the control rates proposed in the Arkansas FIP.

2.4.1. Emissions Inventory Updates

Entergy's baseline scenario (Scenario One) also served as the basis for the Proposed Arkansas FIP Scenario. Specific inventory updates include the revision of the emission rates of all Arkansas BART sources and the Independence units to the proposed post-control emission rates identified in the Arkansas FIP.

CAMx model outputs were post-processed and analyzed to determine the visibility effects of each of the Arkansas FIP sources. In order to obtain comparable results to EPA's CAMx modeling, the same post-processing approach was utilized, which involves the conversion of binary CAMx output files into a readable format, the extraction of relevant regional haze pollutant concentration information, and the calculation of relative response factors (RRF) using EPA's Modeled Attainment Test Software (MATS). Calculation workbooks also provided by the EPA were then used to determine visibility impacts. The full post-processing procedure used to analyze each modeling scenario is discussed in detail below.

3.1.1. Introduction to Atmospheric Visibility

The primary purpose of the Regional Haze Rule is to improve visibility at mandatory Class I areas. In practical terms, visibility at Class I areas is most simply measured as the farthest distance that can naturally be seen by an average human. Light waves diffract and are absorbed as they pass through and around particles and molecules in the atmosphere. The level of visibility therefore naturally decreases at greater distances as light waves come into contact with a greater number of these miniscule obstacles. This scattering of light waves is called Rayleigh scattering. In eastern areas of the United States, it is estimated that without the effects of anthropogenic pollution, visibility is naturally limited to a distance of approximately 90 miles, while in western areas the natural visible range is approximately 140 miles.[7]

As atmospheric concentrations of particles and molecules increase, the level of visibility further decreases since light waves can potentially interact with a larger number of obstacles at equivalent distances. Therefore, pollution from both anthropogenic and non-anthropogenic sources can have a significant effect on visibility in Class I areas. The primary contributors to visibility impairment include sulfates, nitrates, organic carbon, elemental carbon, crustal material, and sea salt."[8, 9]

In addition to visual range, another useful visibility measurement is the light extinction coefficient, which represents the gradual decrease in light intensity due to absorption and scattering. The light extinction coefficient can be calculated using measured concentrations of the primary contributing species to visibility impairment.[10] At Class I areas, the concentrations of these species are monitored by the Interagency Monitoring of Protected Visual Environments (IMPROVE), which analyzes 24-hour duration samples every 3 days. In 1999, an equation to estimate light extinction based on available IMPROVE data was incorporated into the Regional Haze Rule (Old IMPROVE equation). In 2007, a revised equation was developed to reduce "bias for high and low light extinction extremes" and to make the equation "more consistent with the recent atmospheric aerosol literature." This equation is given as follows:

[7] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

[8] Ibid.

[9] Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.

[10] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

$$
\begin{aligned}
b_{ext} = 2.2\ & \times f_S(RH) \times [Small\ Sulfate] \\
& + 4.8 \times f_L(RH) \times [Large\ Sulfate] \\
& + 2.4 \times f_S(RH) \times [Small\ Nitrate] \\
& + 5.1 \times f_L(RH) \times [Large\ Nitrate] \\
& + 2.8 \times [Small\ Organic\ Mass] \\
& + 6.1 \times [Large\ Organic\ Mass] \\
& + 10 \times [Elemental\ Carbon] \\
& + 1 \times [Fine\ Soil] \\
& + 1.7 \times f_{SS}(RH) \times [Sea\ Salt] \\
& + 0.6 \times [Coarse\ Mass] \\
& + Rayleigh\ Scattering\ (Site\ Specific) \\
& + 0.33 \times [NO_2(ppb)]
\end{aligned}
$$

Where b_{ext} represents the light extinction coefficient in inverse megameters (Mm^{-1}), and individual species concentrations are shown in brackets with units of micrograms per cubic meter ($\mu g/m^3$). The f_L and f_S terms are unitless water growth factors given as functions of relative humidity (RH) for concentrations of large and small sulfates and nitrates, while f_{SS} represents the water growth factor for sea salt concentrations. The numerical constants given in the equation (e.g., 2.2) represent dry mass extinction efficiency terms in units of square meters per gram (m^2/g).[11]

Because the units for the light extinction coefficient (MM^{-1}) are difficult to conceptualize and compare in practical terms, the deciview haze index (dv) was developed. The deciview haze index is calculated as a function of the ratio of the calculated light extinction coefficient to the approximate average extinction value due to Rayleigh scattering alone (10 Mm^{-1}).

$$Deciview\ Haze\ Index\ (dv) = 10 \times \ln\left(\frac{b_{ext}\ [Mm^{-1}]}{10\ [Mm^{-1}]}\right)$$

The deciview scale provides a simpler representation of visibility deterioration, with natural conditions having a calculated deciview haze index of approximately zero, depending on the site-specific level of Rayleigh scattering.[12]

3.1.2. MATS Processing

The raw CAMx output data most relevant to this regional haze assessment includes an overall average concentration file and a source apportionment concentration file, for each grid utilized (i.e., 12 km and 36 km grids) and for all modeled dates. These raw output files are in Fortran binary and are based on the Urban Airshed Model (UAM) convention. Several post-processor utility programs are used to convert these UAM formatted output files into MATS ready comma separated value (CSV) input files for individual source groups identified by PSAT.

MATS forecasts the level of visibility at Class I areas by using post-processed CAMx modeling output in accordance with monitoring data from the IMPROVE program. The three primary files required to run MATS are

[11] Kumar, Naresh, et al. "Revised Algorithm for Estimating Light Extinction from IMPROVE Particle Speciation Data." Journal of the Air & Waste Management Association JAWMA 57.11 (2007): 1326-336.

[12] United States Environmental Protection Agency. *Visibility in Mandatory Federal Class I Areas (1994-1998): A Report to Congress*. EPA-452/R-01-008. Chapter 1 – Introduction to Visibility Issues. November 2001.

the base year model CAMx output, the future year model CAMx output, and the IMPROVE monitoring data. For the purposes of this modeling assessment, 2002 was selected as the base year. The 2018 future year model output refers to each of the CSV files created. The IMPROVE monitoring data is provided as sample data in the MATS software package download from the EPA.

First, MATS uses the IMPROVE monitoring data to identify the 20% best and 20% worst visibility days at each Class I area for the base year, 2002. Using the base year modeled output data on these exact same 20% best and 20% worst days, MATS calculates the average 20% best and 20% worst modeled concentrations of each of the pollutants identified (e.g., sulfates, nitrates, etc.). MATS then performs the same calculations using the same days with the 2018 future year model data. These values are next used to calculate relative response factor (RRF) values, which are ratios of future year modeled concentrations to base year modeled concentrations, both predicted near the same Class I area. The result of this step is a set of best and worst RRF values calculated for all identified species at each Class I area. These RRF values are used in accordance with IMPROVE monitoring data to forecast future deciview haze index values.

The final output from the MATS analysis includes, but is not limited to, the best and worst RRF values calculated for each species and Class I area, the best and worst average daily deciview haze index values for each valid year and Class I area, and the annual average deciview haze index values for each Class I area. In order to perform the required calculations for the PSAT source contribution analysis, all eleven PSAT-negated CSV files were also processed by MATS so that specific PSAT-negated RRF values could be calculated for each PSAT source. These RRF values represent the relative response of each modeled pollutant concentration resulting from the removal of each PSAT source.

3.1.3. PSAT Source Contribution Analysis

The PSAT source contribution analysis determines the individual impact of each PSAT source on visibility at Class I areas. As described in earlier sections, the impacts of the Arkansas BART sources and Entergy's Independence units were traced by the CAMx PSAT tool. The source apportionment CAMx output files were post-processed through MATS to calculate RRF values, which were then used in contribution analysis workbooks provided by the EPA. The calculations in these workbooks are based on the New IMPROVE equation, the IMPROVE monitor data, and the RRF values calculated by MATS.

The contribution analysis workbooks are designed to retrieve the monitored concentrations of visibility impairing pollutants associated with the 20% worst visibility days from 2002 (base year) IMPROVE data, and to multiply them by the 2018 future year RRF values as well as the PSAT-negated RRF values associated with each PSAT source. The resulting values are input to the New IMPROVE equation, which calculates the 2018 projected light extinction values for each of the 20% worst days. These extinction values are averaged and converted into deciview haze index values. PSAT-negated haze index values represent the total 2018 deciview haze index value minus the contribution of the individual PSAT source.

The individual impact of each PSAT source is calculated as the difference between the total 2018 future year haze index value and each PSAT-negated haze index value. For this assessment, the contributions of individual sources located at the same facility were combined in order to compare facility contributions. Figures 3-1 and 3-2 display the uncontrolled baseline scenario facility contributions to deciview haze index for Caney Creek and Upper Buffalo, respectively.

Figure 3-1. Contribution Analysis Results for the Baseline Modeling Scenario at the Caney Creek Wilderness Area

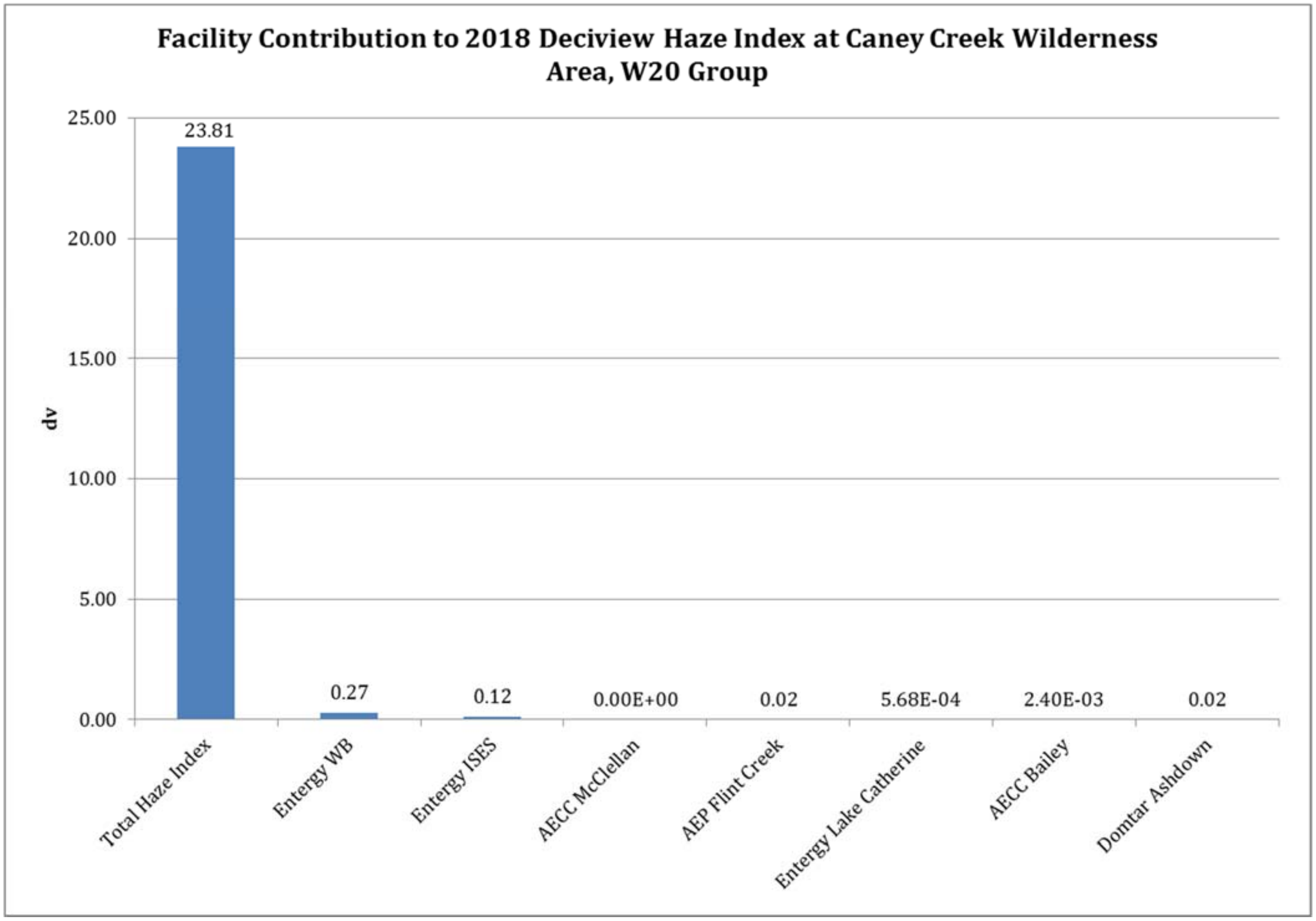
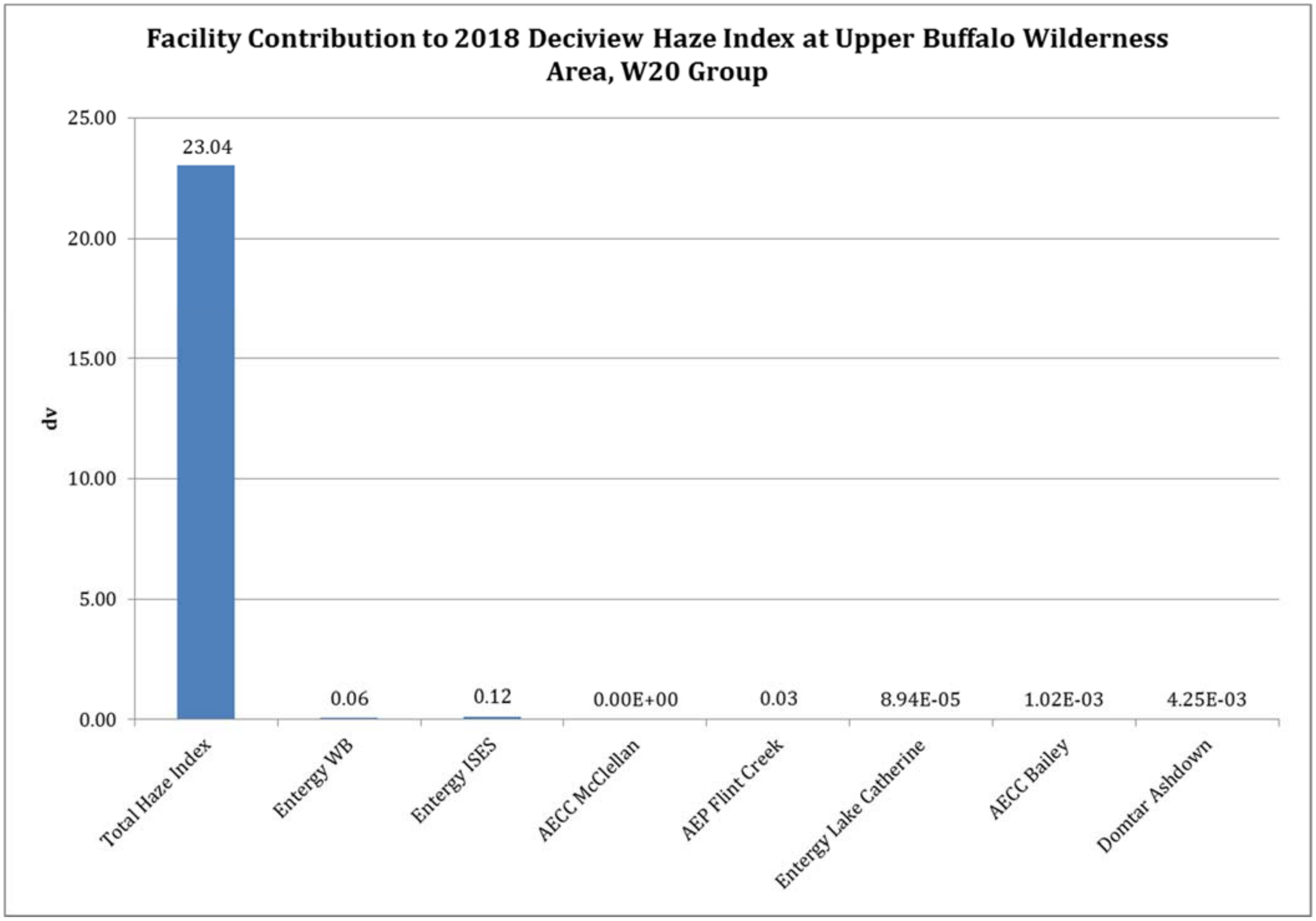


Figure 3-2. Contribution Analysis Results for the Baseline Modeling Scenario at the Upper Buffalo Wilderness Area



3.1.4. Uniform Rate of Progress Curve Analysis

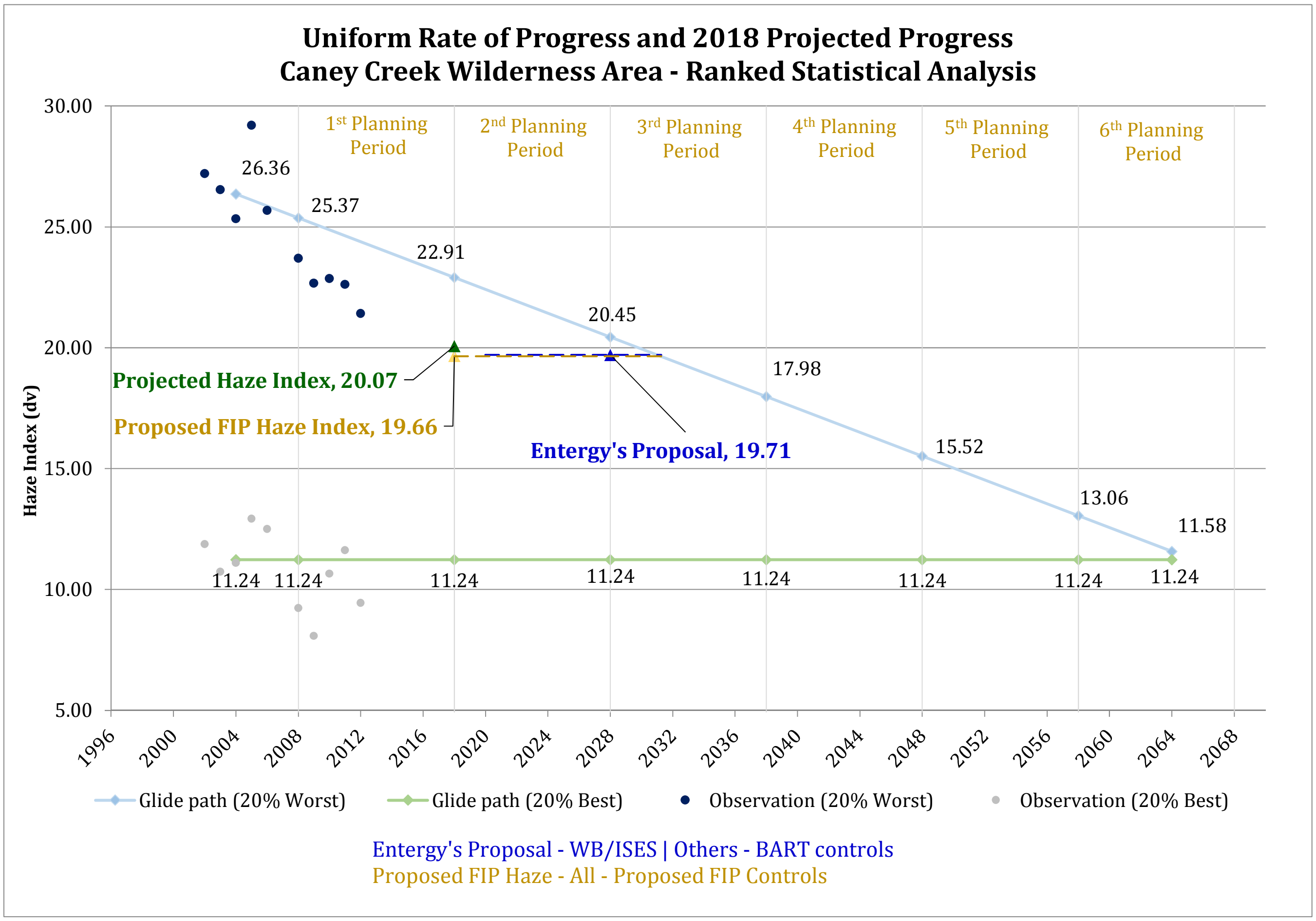
Title 40 of the Code of Federal Regulations (CFR) Part 51 requires that SIPs "analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064."[13] This requirement is demonstrated by creating a URP graph, which shows the rate at which the 20% worst deciview (dv) haze index values are required to improve from year to year in order to reach natural visibility conditions by 2064. The URP graphs are derived from actual observed data for each Class I area collected through the IMPROVE program. The URP graphs are typically initiated in 2004 based on average 2002-2004 IMPROVE data, which was used to calculate the average observed haze index for the 20% worst days and 20% best days. The 2004 initial haze index values are then projected into the future at the minimum rate required to attain natural visibility conditions by 2064. Figures 3-3 and 3-4 display URP curves for Caney Creek and Upper Buffalo, respectively.

Each of these figures display the 20% best and 20% worst URP curves, the average of the 20% best and 20% worst observed deciview haze index values for each year of complete IMPROVE data, and projected haze index values for each modeled scenario. The Projected Haze Index values are obtained from a statistical analysis

[13] *Regional Haze Program Requirements.* 40 CFR §51.308(d)(1)(i)(B).

performed using the full set of IMPROVE data for both Caney Creek and Upper Buffalo.[14] The scenario-specific haze index values are calculated by first converting the model-predicted five-year averaged haze index values obtained from MATS into total extinction values in Mm^{-1}. The predicted improvement associated with each scenario is then calculated by finding the difference between the extinction values from the scenario of interest (i.e., Proposed FIP or Entergy's Proposal) and the uncontrolled baseline scenario. The improvement from each scenario is then subtracted from the Projected Haze Index value and converted back into deciviews to obtain scenario-specific haze index values.

Figure 3-3. Uniform Rate of Progress Analysis Results for the Proposed Control Scenarios at the Caney Creek Wilderness Area



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[14] Trinity Consultants. "IMPROVE Data Statistical Analysis: Discussion and Methodology for IMPROVE Data Statistical Analysis." July 2015.

Figure 3-4. Uniform Rate of Progress Analysis Results for the Proposed Control Scenarios at the Upper Buffalo Wilderness Area

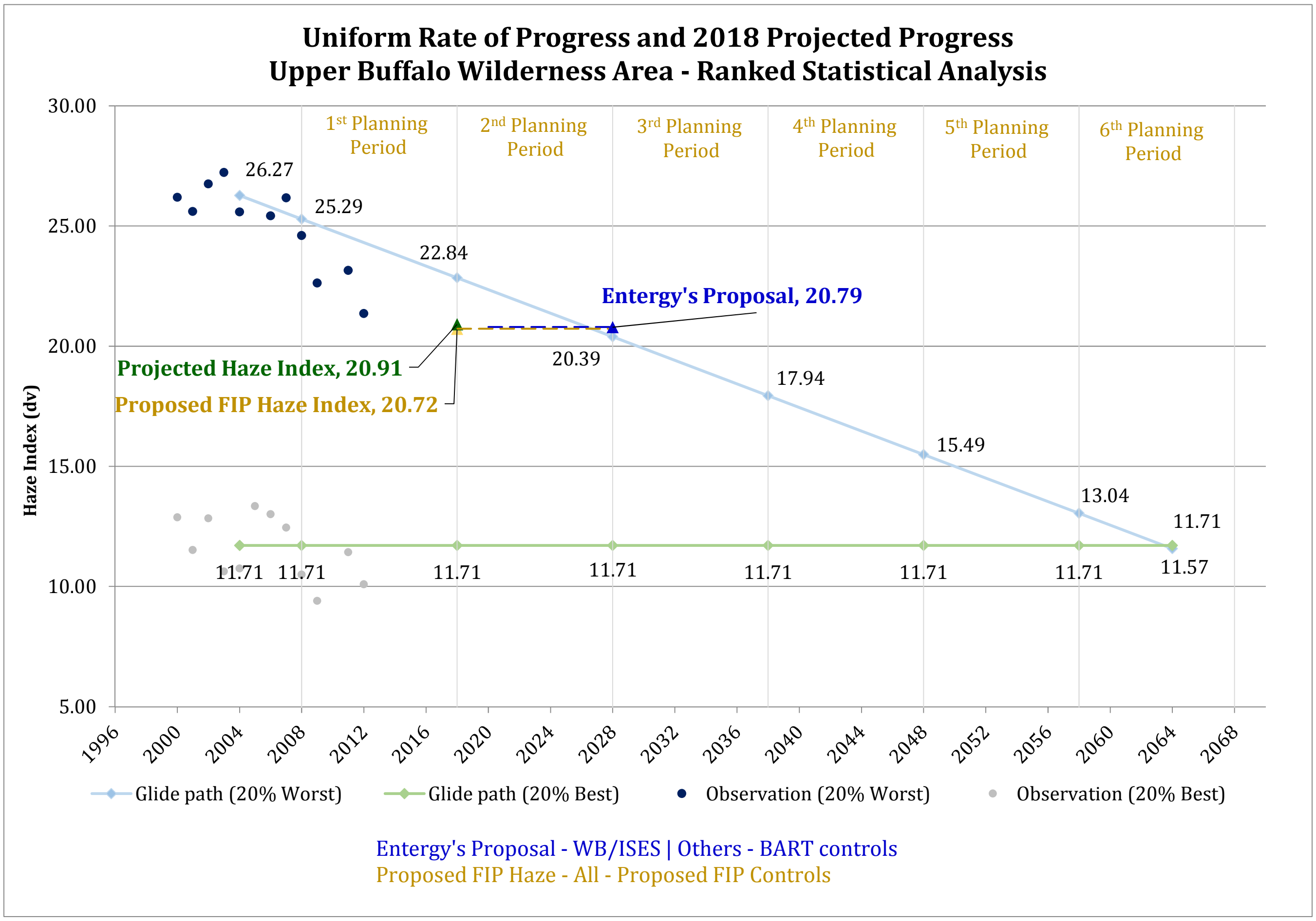

Exhibit C to EAI Comments

Appendix Table A-1. Modeled Emission Rates for the Entergy Independence and White Bluff Units

Unit	Uncontrolled Baseline (tpy)		Entergy's Proposal (tpy)		Arkansas FIP (tpy)	
	NO_X	SO_2	NO_X	SO_2	NO_X	SO_2
Independence Unit 1	6,313	14,258	3,150	12,154	3,619	1,357
Independence Unit 2	6,516	15,407	3,347	13,162	3,167	1,521
White Bluff Unit 1	7,580	15,939	--[1]	--[1]	4,145	1,453
White Bluff Unit 2	8,145	16,034	--[1]	--[1]	4,060	1,476
Lake Catherine Unit 4	1,228	3.26	564	3.26	564	3.26

[1] Entergy's Proposal includes the cessation of coal combustion at White Bluff.

IMPROVE DATA STATISTICAL ANALYSIS

Entergy Arkansas Inc.

THE POWER OF PEOPLE℠

Discussion and Methodology for IMPROVE Data Statistical Analysis

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July 2015

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1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published the proposed Arkansas Regional Haze Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. Within the Arkansas FIP, the EPA addressed the portions of the Arkansas State Implementation Plan (SIP) which the EPA disapproved in its final action, published March 12, 2012.[1] In addition to addressing the control requirements for Arkansas sources determined to be subject to Best Available Retrofit Technology (BART), the EPA also addresses the Reasonable Progress Goals (RPGs) and reasonable progress control requirements. Specifically, the EPA proposed to meet RPGs by presenting options for controlling emissions from the Entergy Arkansas Inc. (Entergy) Independence Plant (ISES), which is not subject to BART.

Trinity Consultants Inc. (Trinity) was tasked with conducting a statistical analysis of observed visibility data gathered through the Interagency Monitoring of Protected Visual Environment (IMPROVE) program to statistically determine the future trends in the regional haze index values. Trinity conducted a simple Trend Statistical Analysis and more robust Ranked Statistical Analysis to determine the projected haze index in 2018.

[1] Environmental Protection Agency. Approval and Promulgation of Implementation Plans; Arkansas; Regional Haze State Implementation Plan; Interstate Transport State Implementation Plan To Address Pollution Affecting Visibility and Regional Haze. Federal Register Volume 77, Number 48. March 12, 2012.

2. INTRODUCTION

Title 40 of the Code of Federal Regulations (CFR) Part 51 requires that SIP "analyze and determine the rate of progress needed to attain natural visibility conditions by the year 2064."[2] This requirement is demonstrated by creating a Uniform Rate of Progress (URP) graph, which shows the rate at which the 20% worst deciview (dv) haze index values are required to improve from year to year in order to reach natural visibility conditions by 2064. The URP graphs, also known as glide paths, are derived from actual observed data for each Class I area collected through the IMPROVE program. The URP graphs typically were initiated in 2004 based on average 2002 – 2004 IMPROVE data, which was used to calculate the average observed haze index for the 20% worst days and 20% best days. The 2004 values were then projected into the future to intersect with the 20% best days observed value by 2064. To demonstrate attainment with this glide path, the Central Regional Air Planning Association (CENRAP) used the Comprehensive Air Quality Model with Extensions (CAMx) to perform regional haze modeling. The model-predicted haze index values based on the future projected emission rates are used to compare with the glide path proposed value in 2018, the end of the 1st planning period. Figures 2-1 and 2-2 display the uniform rate of progress glide paths for the Caney Creek Wilderness Area (Caney Creek) and the Upper Buffalo Wilderness Area (Upper Buffalo) along with the CENRAP projected haze index.

In addition to the glide paths for the 20% worst days and 20% best days, the URP graphs also present the observed 20% worst and 20% best haze index values from the IMPROVE monitoring observational data for 2002 to 2012. As presented in Figures 2-1 and 2-2 for Caney Creek and Upper Buffalo, respectively, the observed values are well below the glide path with a consistent downward trend in the observations. This downward trend is consistent with the historical (2002 – 2011) trend in decreasing sulfur dioxide (SO_2) emissions from tier 1 sources located in the states contributing significantly to the Caney Creek and Upper Buffalo Class I Areas. Figure 2-3 presents the National Emissions Inventory (NEI) SO_2 emissions from 2002, 2005, 2008, and 2011. Pursuant to the NEI emissions data, the SO_2 emissions have significantly decreased since 2005 to 2011 in all source categories, including especially a more than 50% drop due to fuel combustion from electric utilities and a 67% drop in the fuel combustion from industrial sources. Based on the significant downward trend in the observed data and the actual SO_2 emissions data, the future haze index value in 2018 is expected to be lower than the currently predicted glide path. The lower haze index value in 2018 will be additionally supported by the anticipated implementation of regulations further curbing emissions.

[2] *Regional Haze Program Requirements.* 40 CFR §51.308(d)(1)(i)(B).

Figure 2-1. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress

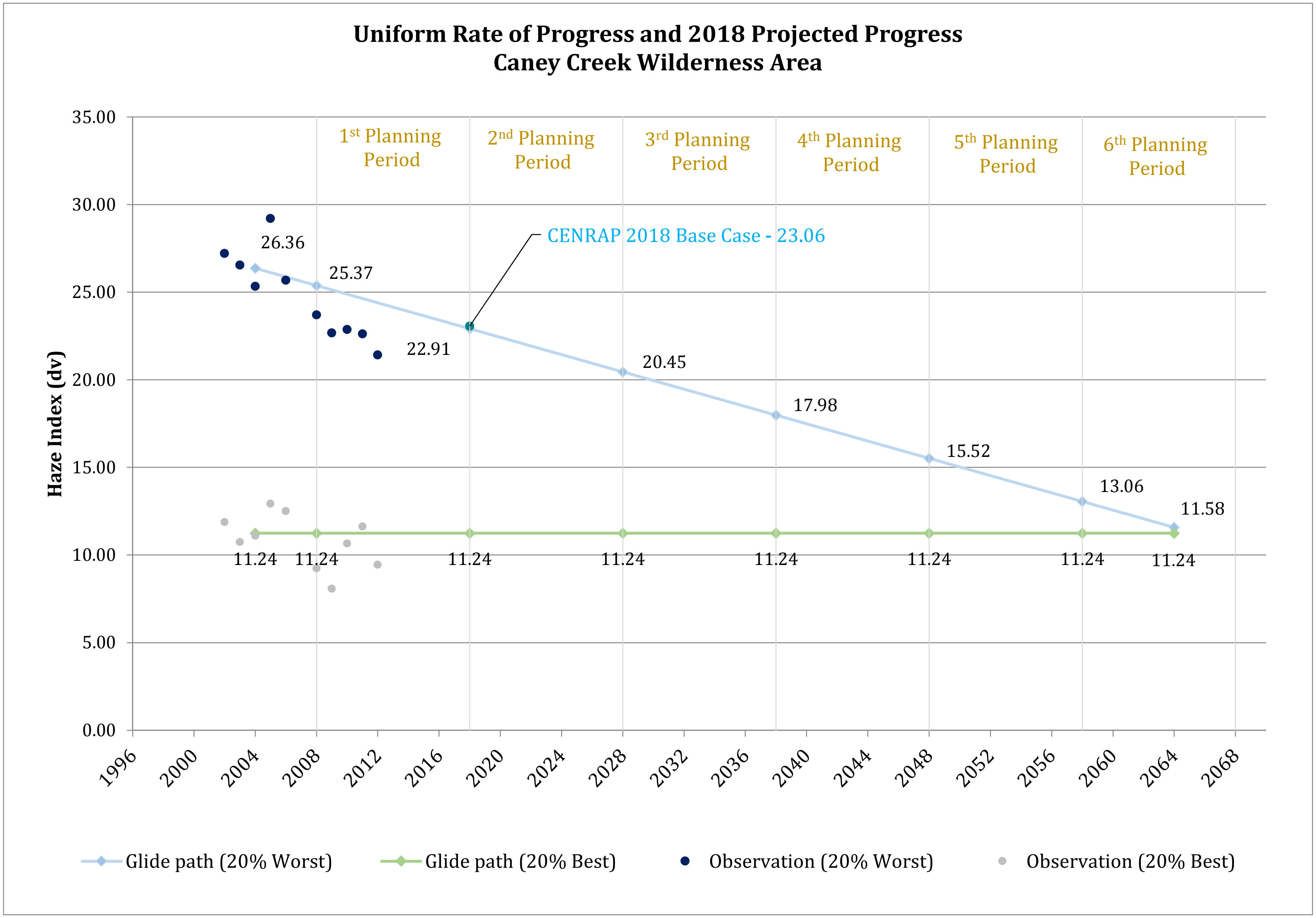


Figure 2-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress

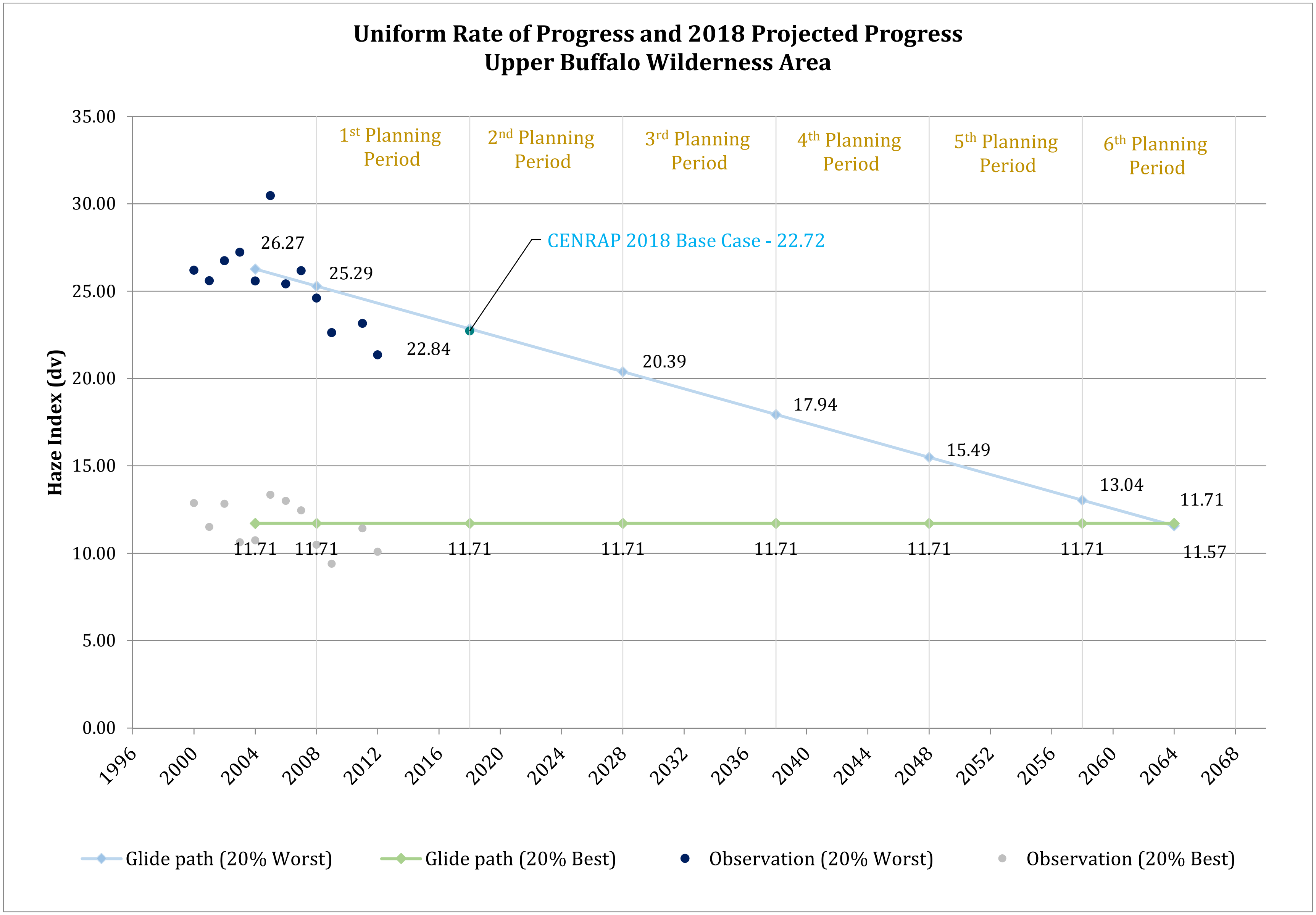


Figure 2-3. National Emissions Inventory (NEI) – SO_2 Emissions for States Contributing Significantly to Light Extinction at Caney Creek and Upper Buffalo

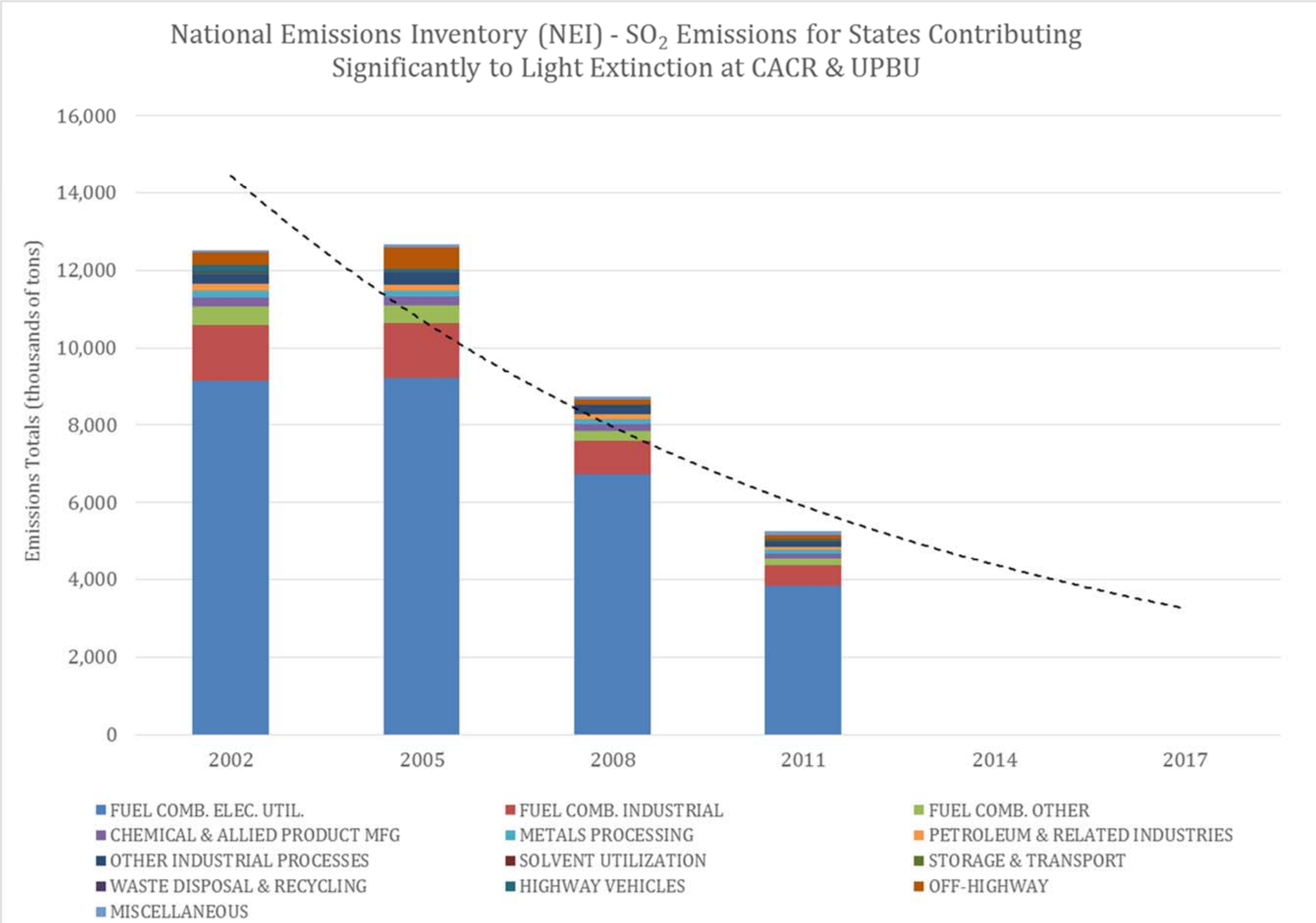


Exhibit D to EAI Comments

Based on the above, when looking at the observed values, the CENRAP model predicted regional haze value for 2018 is overly conservative and over predicting the future haze index. Although the predicted 2018 haze index values are good conservative estimates for attainment demonstrations, the values are misleading when assessing the effect of proposed controls on single sources. Additionally, the CENRAP CAMx model predicted haze index does not account for the observed values and the trend predicted if an assessment occurred evaluating the observed values. Therefore, instead of using the CENRAP CAMx predicted 2018 haze index to understand the effect of the control options, a statistically derived projected haze index must be used.

In order to statistically calculate the future deciview haze index values using observed data instead of relying on the CENRAP modeling, two statistical analyses were performed and evaluated to determine the most appropriate analysis for predicting the haze index values based on observed data:

- Trend Analysis
- Ranked Statistical Analysis

Each of these analyses are summarized in Section 3 of this report.

3.1. TREND STATISTICAL ANALYSIS

A trend analysis using a simple least squares linear regression based on the annual average values was performed. Using this simple "Trend Analysis" methodology, the projected 2018 deciview haze index values of **18.02** dv and **20.44** dv were determined for Caney Creek and Upper Buffalo, respectively. Figures 3-1 and 3-2 present the uniform rate of progress glide paths for Caney Creek and Upper Buffalo when the 2018 projected haze index is based on the statistical trend of the observed data. These values are estimated without consideration of additional controls added as a result of the proposed FIP. Presented alongside these projected values are the estimated values that would result from adopting the proposed FIP controls (Proposed FIP Haze Index) as well as the controls proposed by Entergy (Entergy's proposal). Entergy's proposal includes meeting more stringent SO_2 emission rates at ISES and Entergy's White Bluff plant (WB) by 2018, the installation of low nitrogen oxides (NO_X) burners at ISES and WB, and the cessation of coal combustion at the WB plant by 2028.

This statistical analysis is not, however, a realistic model for expected visibility improvement since this trend is based on a limited set of data—the 20% worst deciview haze index values for each year—which may not be representative of the complete set of IMPROVE data. Therefore, a more extensive statistical analysis was performed to predict future deciview haze index values based on the full set of IMPROVE observation data.

A review of the IMPROVE data sets for both Caney Creek and Upper Buffalo indicate that there is no convincing correlation between the observed deciview haze index value and the date of observation. That is, there is no detectable temporal trend in the IMRPOVE data. However, as shown in Figure 3-3, the maximum, third quartile, median, first quartile, and minimum data points do indicate a consistent downward trend from year to year, which suggests that over time, from year to year and month to month, the first highest, second highest, third highest, etc. observed values will follow a trend which can be used to predict future values.

IMPROVE data obtained for both Caney Creek and Upper Buffalo spanned the years 2000 to 2012 where data is taken every three days. However, both IMPROVE data sets contain regions of time for which data is not available. Because some years have less data points than other years, it is therefore impossible to predict future deciview haze index values using the n^{th} largest value without introducing unnecessary biased skew. For example, the Caney Creek IMPROVE data for 2000 includes only 52 values while 2004 contains 122 values. Therefore, the 52^{nd} highest value (also the minimum value) for 2000 is 4.04 dv while the 52^{nd} highest value for 2004 is 20.00 dv. Since it would be inappropriate to compare the minimum value of 2000 with a value closer to the median of 2004, further refinement to the methodology is required.

One option is to simply remove years with data not meeting a defined criteria for completeness. This option, however, is not preferred because it discounts a large quantity of valuable data. Additionally, this option only slightly reduces the potential for skew described above. The final chosen methodology (Ranked Statistical Analysis) addresses both of these issues by minimizing the skew due to incomplete data while maximizing the usage of available data.

Figure 3-1. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Trend Analysis.

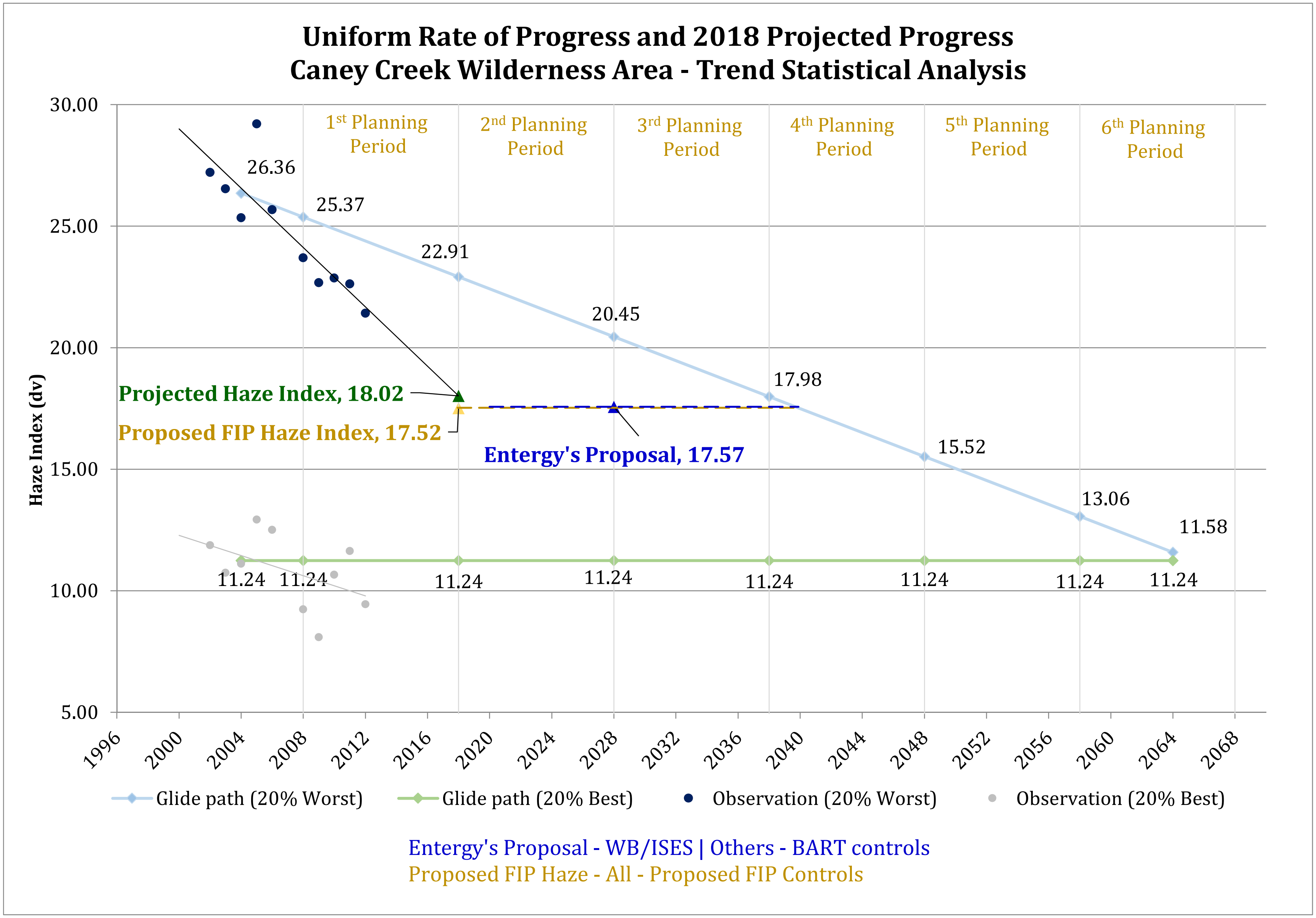


Figure 3-2. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Trend Analysis.

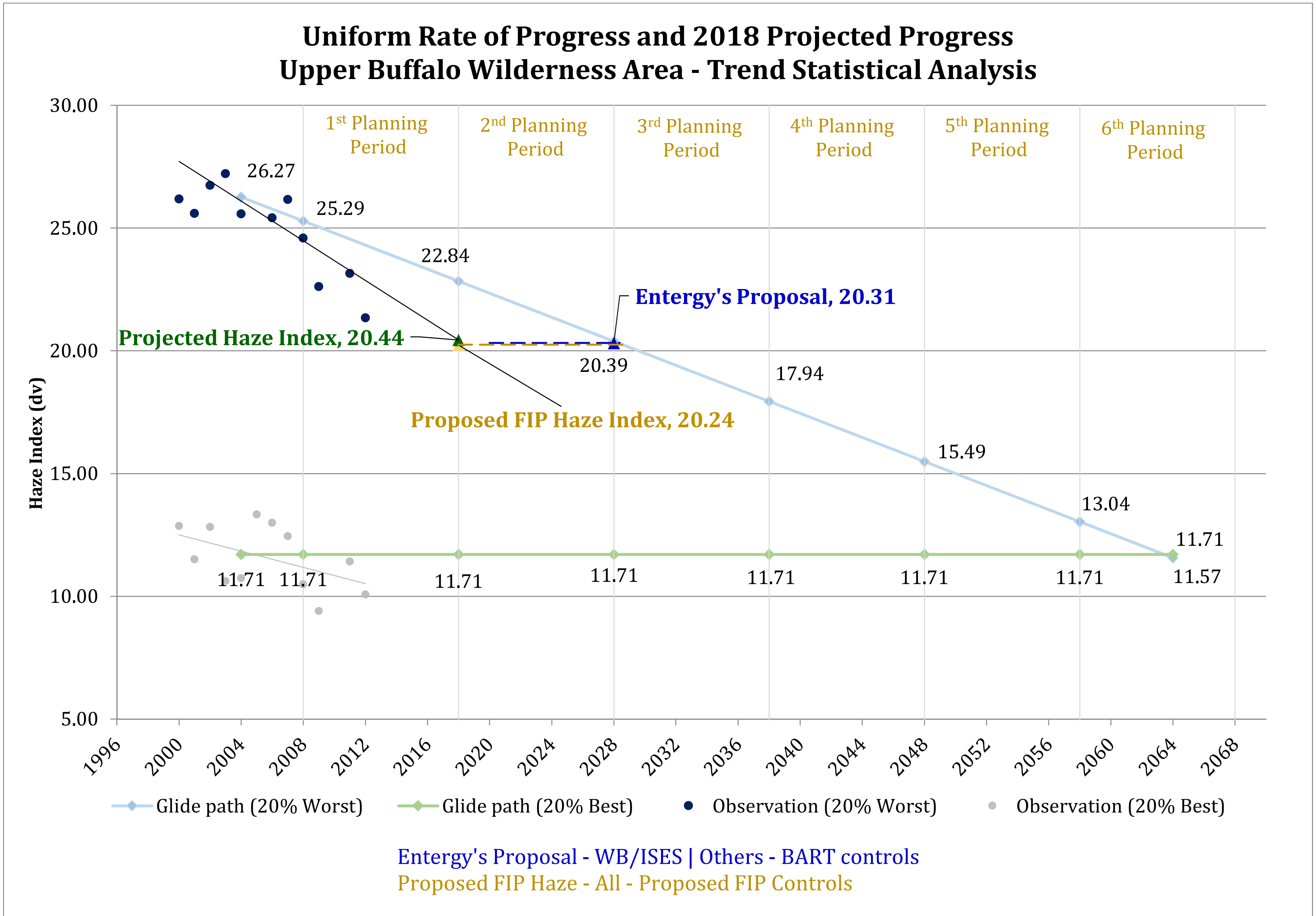
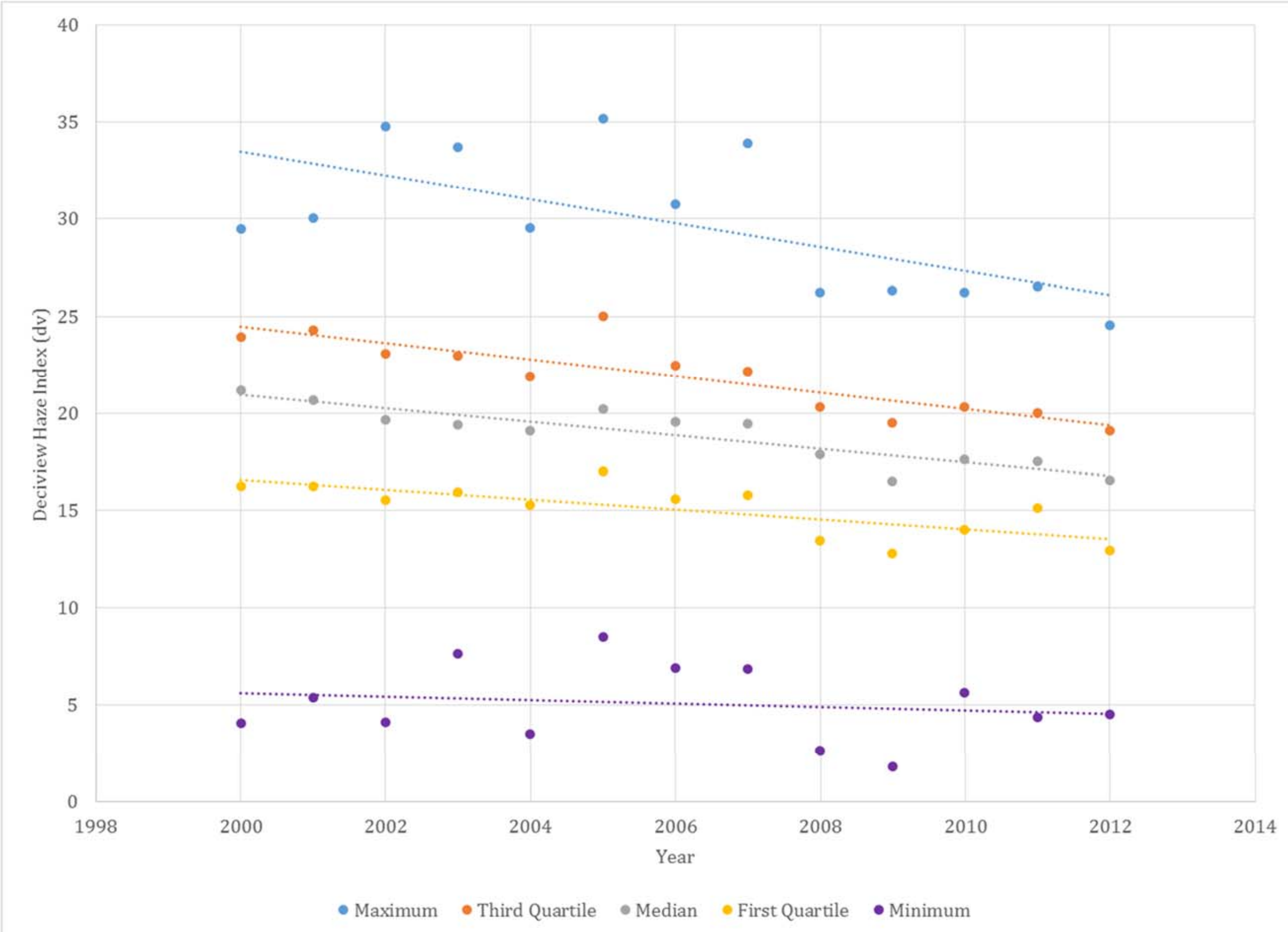


Exhibit D to EAI Comments

Figure 3-3. Observed Trends in Statistical Values for Caney Creek IMPROVE data.



3.2. RANKED STATISTICAL ANALYSIS

The chosen methodology, described as Ranked Statistical Analysis, begins with the chronological organization of the IMPROVE data from every year, as displayed in Table 3-1 as an example. It was determined that a month of data is incomplete for a year if less than nine (9) days of data points are available (eight days for February) for that month. This completion criteria corresponds to approximately overall 90% completeness. Table 3-2 presents the resulting completeness determinations of each month and year for Caney Creek. If a given month has less than nine out of thirteen years of complete data, that month is discounted from the calculations and is not considered in the future projections. As shown in Table 3-2, April only had eight years of complete data for Caney Creek; therefore, April was not considered in the projections. Once the completeness determination was completed, the haze index values for each complete month and year were then ranked so that the values for each month from year to year were aligned in descending order. Table 3-3 presents the ranked observations for Caney Creek for the complete years of January data as an example. These ranked monthly values were used to predict the daily haze index values for each month of the year 2018. Using this set of predicted 2018 values, the 2018 average of the 20% worst days for visibility was calculated to be **20.07** dv for Caney Creek and **20.91** dv for Upper Buffalo. Figures 3-4 and 3-5 display these predicted 2018 values in relation to the URP curves for each Class I Area. Also displayed are the estimated proposed FIP haze index and the haze index based on Entergy's proposed controls.

The haze index values predicted using the Ranked Statistical Analysis are consistent with the downward trend from the observed values and are more conservative than the Trend Analysis. The Trend Analysis relies on the sampling data generated from average worst 20% days IMPROVE data and therefore, the sampling data is limited to only one (1) value per year. This limited size of sampling can induce some bias in the statistical analysis. However, the statistical samples in the Ranked Statistical Analysis, unlike the Trend Analysis, includes at least nine (9) values per month or a minimum of 108 data points for each complete year. The sample data used for the Ranked Trend Analysis included at least 8 complete years or a minimum of 860 data points. The use of this large data sample in the Ranked Statistical Analysis makes this analysis more robust and un-biased in predicting the projected trends. The use of a larger sample point ranked on a monthly basis also preserves the temporal and diurnal patterns in the observed data. By predicting monthly future values, these diurnal and temporal pattern are sustained in the statistical analysis and therefore, reduce the bias due to missing values.

Based on statistical analysis completed, the Ranked Statistical Analysis is more appropriate for determining the downward trend in the haze index based on IMPROVE observed data. When comparing the ranked versus trend analyses, the trend analysis would suggest the programs external to the Regional Haze rule will have a more profound effect on the glide path which will approach the natural background in 2028 and 2042 for Caney Creek and Upper Buffalo, respectively. When looking at the more conservative Ranked Statistical Analysis, the URP will be approached after 2038/2044 for Caney Creek and Upper Buffalo, respectively, but well before the 2064 deadline. Under either approach, analysis of the data trends show that the rate of visibility improvement is outpacing the URP graphs at both Caney Creek and Upper Buffalo.

Table 3-1. Chronological Deciview Haze Index Values Observed in January at the Caney Creek Wilderness Area

Julian Day	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
1	--	--	--	--	14.59	--	--	--	10.24	18.60	--	--	11.70
2	--	--	21.27	--	--	--	--	--	--	--	20.47	--	--
3	--	--	--	19.27	--	--	--	18.54	--	--	--	14.72	--
4	--	--	--	--	13.18	11.69	--	--	--	22.85	--	--	14.80
5	--	--	17.81	--	--	--	6.88	--	--	--	17.32	--	--
6	--	--	--	20.09	--	--	--	23.10	--	--	--	12.71	--
7	--	--	--	--	15.61	10.71	--	--	--	10.80	--	--	18.88
8	--	--	18.18	--	--	--	13.96	--	--	--	14.95	--	--
9	--	--	--	20.33	--	--	--	6.86	--	--	--	12.89	--
10	--	--	--	--	29.56	14.03	--	--	--	26.11	--	--	12.66
11	--	--	14.41	--	--	--	13.61	--	--	--	18.43	--	--
12	--	--	--	15.61	--	--	--	13.10	--	--	--	20.13	--
13	--	--	--	--	26.26	17.13	--	--	--	15.40	--	--	6.80
14	--	--	10.42	--	--	--	7.68	--	--	--	19.31	--	--
15	--	--	--	27.57	--	--	--	--	--	--	--	25.25	--
16	--	--	--	--	19.61	24.99	--	--	--	14.47	--	--	14.97
17	--	--	21.57	--	--	--	17.86	--	--	--	18.75	--	--
18	--	--	--	15.35	--	--	--	--	--	--	--	19.63	--
19	--	22.79	--	--	19.40	--	--	--	--	19.58	--	--	--
20	--	--	--	--	--	--	18.74	--	--	--	18.14	--	--
21	--	--	--	21.74	--	--	--	--	--	--	--	12.33	--
22	--	21.70	--	--	24.23	20.17	--	--	--	21.15	--	--	18.07
23	--	--	15.85	--	--	--	13.47	--	--	--	13.43	--	--
24	--	--	--	17.45	--	--	--	16.37	--	--	--	21.59	--
25	--	--	--	--	11.67	21.57	--	--	15.07	21.52	--	--	4.52
26	--	--	14.01	--	--	--	9.72	--	--	--	7.38	--	--
27	--	--	--	25.98	--	--	--	19.94	--	--	--	17.15	--
28	--	22.76	--	--	14.65	19.52	--	--	18.43	20.24	--	--	10.71
29	--	--	20.39	--	--	--	12.82	--	--	--	11.21	--	--
30	--	--	--	17.81	--	--	--	15.78	--	--	--	20.67	--
31	--	13.34	--	--	19.07	17.61	--	--	10.74	8.28	--	--	19.91

Table 3-2. Determination of Monthly and Yearly Data Completeness for the Caney Creek Wilderness Area

Month	Total Number Days	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Number of Complete Years
January	31	No	No	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes	Yes	Yes	9
February	28	No	No	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	9
March	31	No	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	11
April	30	No	No	Yes	Yes	Yes	Yes	Yes	No	No	No	Yes	Yes	Yes	8
May	31	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	12
June	30	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	11
July	31	No	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	10
August	32	No	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	9
September	30	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	Yes	11
October	30	Yes	No	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	No	Yes	10
November	30	Yes	No	Yes	Yes	Yes	Yes	No	No	Yes	No	Yes	Yes	Yes	9
December	31	No	No	Yes	Yes	Yes	No	Yes	No	Yes	Yes	Yes	Yes	Yes	9

Table 3-3. Ranked Deciview Haze Index Values for the Caney Creek Wilderness Area in January

	2002	2003	2004	2005	2006	2009	2010	2011	2012	Number of Days with Data
1	21.57	27.57	29.56	24.99	18.74	26.11	20.47	25.25	18.88	9
2	21.27	25.98	26.26	21.57	17.86	22.85	19.31	21.59	18.07	9
3	20.39	21.74	24.23	20.17	13.96	21.52	18.75	20.13	14.97	9
4	18.18	20.33	19.61	19.52	13.61	21.15	18.43	19.63	14.80	9
5	17.81	20.09	19.40	17.61	13.47	19.58	18.14	17.15	12.66	9
6	15.85	19.27	15.61	17.13	12.82	18.60	17.32	14.72	11.70	9
7	14.41	17.45	14.59	14.03	9.72	15.40	14.95	12.89	10.71	9
8	14.01	15.61	13.18	11.69	7.68	14.47	13.43	12.71	6.80	9
9	10.42	15.35	11.67	10.71	6.88	10.80	7.38	12.33	4.52	9
10	--	--	--	--	--	--	--	--	--	0
11	--	--	--	--	--	--	--	--	--	0

Figure 3-4. Caney Creek Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Ranked Statistical Analysis

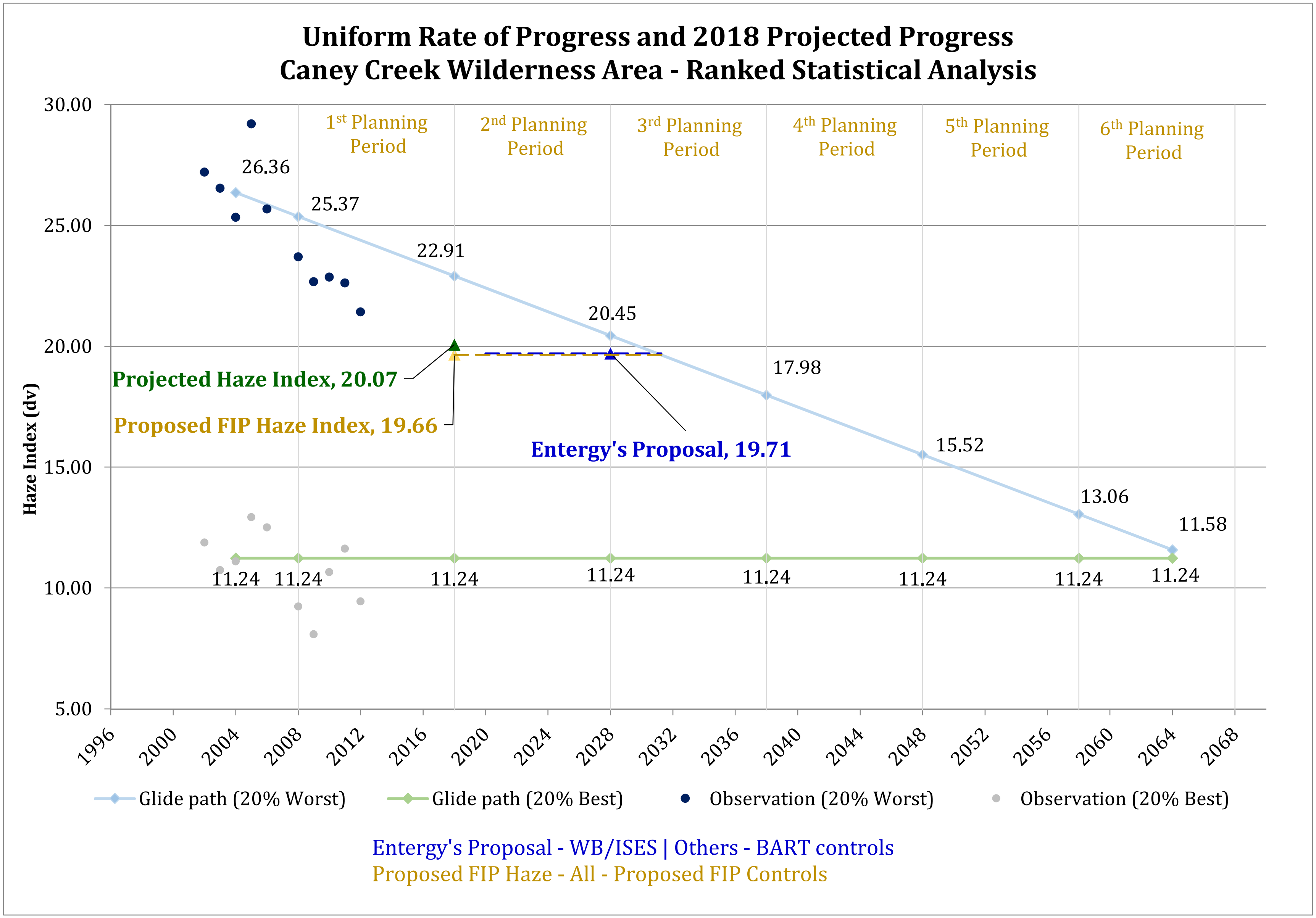
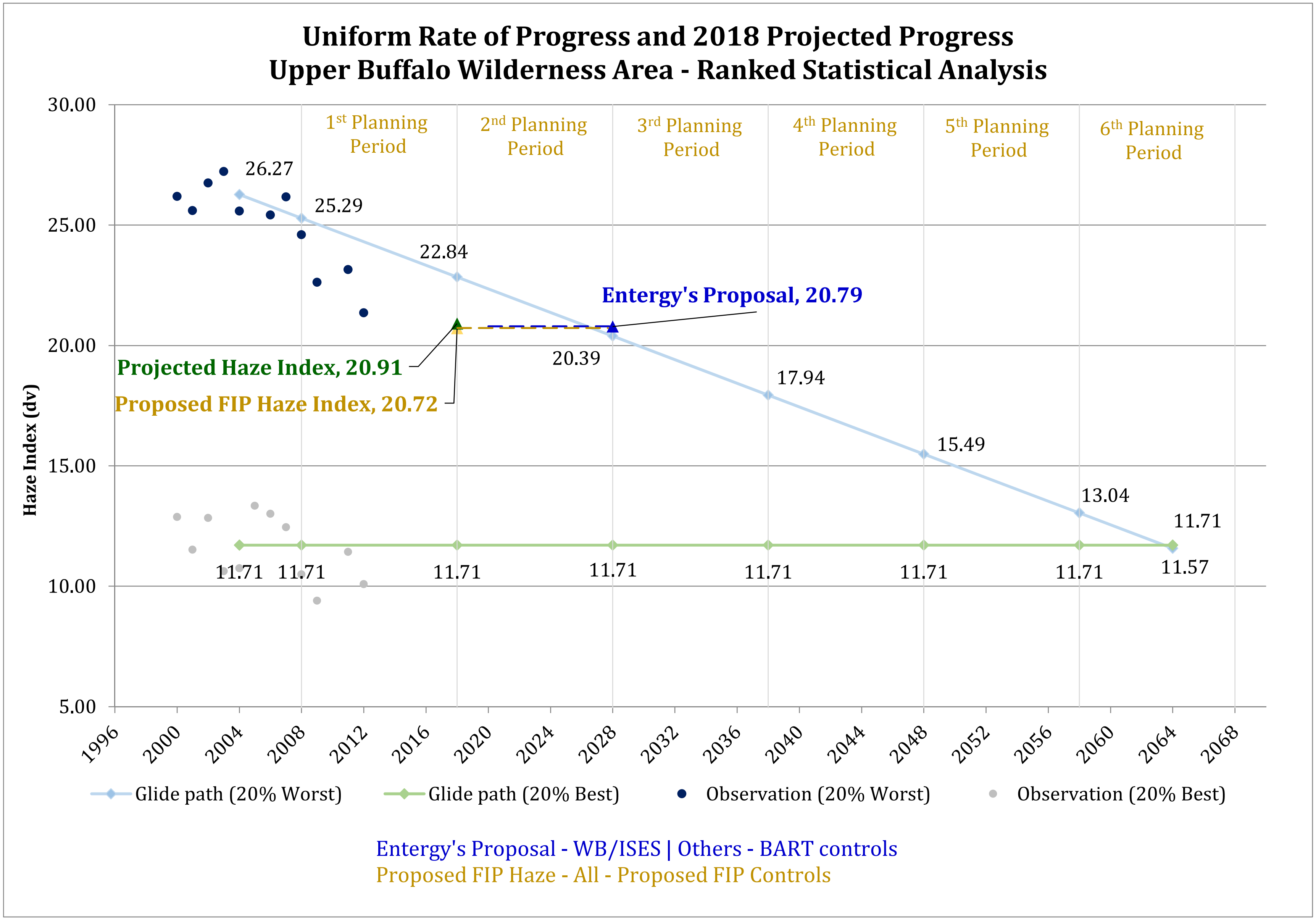


Figure 3-5. Upper Buffalo Wilderness Area Uniform Rate of Progress curve and 2018 Projected Progress with Ranked Statistical Analysis



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Just-Noticeable Differences in Atmospheric Haze

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ABSTRACT

This article examines the only available experimental data taken in the natural environment on the ability of an observer to perceive small, incremental changes in the colorfulness of objects seen through atmospheric haze and estimates an appropriate just-noticeable difference (JND) from these data. This experimentally determined threshold of perception is compared to changes in the deciview scale. Based on these experimental results, the deciview scale is found to not be uniform over a wide range of visibility conditions, as has been previously claimed. In addition, a 1-deciview change never produces a perceptible change in haze, as defined by a 95% probability of producing a measurable change in the colorfulness of an object seen through the haze.

INTRODUCTION

Section 169A of the Clean Air Act sets a national goal of protecting visibility in national parks and other pristine areas. Under regulations promulgated in 1980, the U.S. Environmental Protection Agency (EPA) has taken specific regulatory action to protect visibility in the Grand Canyon National Park by reducing emissions of sulfur dioxide from the Navajo Electric Generating Station near the eastern end of the Grand Canyon and from the Mohave Power Plant at the western end. However, current concerns about visibility degradation stem from regional haze that is difficult or impossible to attribute to individual sources of air pollution. This issue is addressed by regional haze regulations that set a goal of making reasonable progress toward improving regional visibility in five-year increments, leading to the attainment of "natural conditions" by 2064.[1] Progress is to be measured by an innovative visibility metric for regulatory purposes known as the deciview,[2] used instead of visual range or other visibility metrics because it "expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions."[1] One goal of this article is to assess this and other claims about the deciview scale in light of actual measurements of the perception of haziness. Since the deciview scale is meant to quantify small, just-noticeable differences (JNDs) in visibility, a review of the basic concepts of thresholds and JNDs is given.

IMPLICATIONS

Current regulations use the deciview to quantify a perceptible change in regional haze. Based on the results of this article, changes in atmospheric extinction required to meet regional haze regulations calculated using deciviews would probably be too small, sometimes much too small. In addition, these regulations require that progress be assessed over five-year intervals. In this way, the burden of reducing emissions is spread evenly over many years. However, since deciviews are not uniform in perception, it may be that the actual improvement in visibility will not be uniform.

Perceptual Threshold Concepts

For all the senses, thresholds are necessary—otherwise we would be constantly distracted by small, inconsequential changes in the environment. A background of random noise, some from the environment and some produced inside our own sensory organs, would make it next to impossible to form a stable view of the world. Our vision would be like the grainy, speckled images produced by night vision cameras. On a more basic scientific level, the study of thresholds of the senses has led to a deeper understanding of sensory physiology and how our vision and other senses function. For this reason, virtually all studies of thresholds of vision have been carried out under controlled laboratory conditions.

Since laboratory conditions seldom mimic the natural environment, thresholds so determined are generally not useful in predicting perception in the complex natural world. As an example of the drastic effect that experimental conditions can have on perception, consider an experiment to determine the ability of an observer to perceive the difference in the length of two strings—or to put it another way, to determine the threshold for perception of the difference in the length of two strings, or the JND. If the two strings are widely separated when presented to the observer, the threshold will be much greater than if the two strings are presented side by side. The visual equivalent of this is the use of a split image to determine the ability to distinguish color. If two colors are seen as two halves of a disk, the JND is very small, but if one

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color is presented as a full disk, followed a few seconds later by the other color, the JND will be much larger. The topic of the background on which the colors are seen is also important (e.g., if it is black or a complex scene). In general, many conditions influence thresholds; for this reason, the results of laboratory experiments should be applied with great caution to the natural environment. Thus, this article will report and analyze data taken in a unique experiment in the natural environment with a goal of determining a JND in atmospheric haze.

In the above discussion, the terms "threshold" and "JND" have been freely used, but not defined. The naïve definition of a threshold or JND is clear: It is the smallest amount, or change in, a physical stimulus that is detectable. Ideally, a 1-JND change in a stimulus such as contrast or color would always result in the observer seeing a change, and anything less would not. Of course, the senses do not work in this simple on-off manner. In actuality, as the change in the physical stimulus increases, the probability that the observer will detect the change increases as well. Thus, thresholds and JNDs have always been defined by a probability of detection. Furthermore, the sensitivity of people's senses varies from person to person and during a person's life. Even if each person had a single, idealized threshold, the response of the general population would be best described by a probability of detection.

Repeated matching by the method of adjustments is one of the oldest methods of determining a JND. Falmagne[3] described this and other methods to quantify perception. Briefly, the observer is shown a target color and a variable test color and is asked to adjust the test color until it matches the target. Taking random starting points, the matching procedure is repeated as often as is practical. Since the observer has judged the matching color to be the same as the target color, the variability in the matches is a measure of a JND around the target. The standard deviation of the matches is one measure of this variability that is often used; another is the difference between the 75th and the 25th percentile of the match distribution. The method of adjustments has been replaced in laboratory studies by methods that give less control to the observer and more to the researcher and therefore improve the reproducibility of the results (unfortunately, these methods are impractical for field studies). However, JNDs are still defined by some measure related to the probability of detection. The final determination of the value of a JND or threshold is really dependent on how the measurements are made and how the data are interpreted. For the experimental data used in this article, the method of adjustments was used and a JND related to the standard deviation of repeated matches was defined.

Atmospheric Visibility Concepts

In the classical theory of atmospheric visibility, the threshold of contrast perception, that is, the threshold for perception of a large, dark object on the horizon, is assumed to be 2%.[4] This number is somewhat arbitrary. The Federal Aviation Administration (FAA) has taken the more conservative value of 5.5% as a contrast threshold for the definition of visual range, presumably because approaching aircraft seen from a cockpit are usually neither large nor dark. The common formula for visual range, using the 2% threshold, is

$$V_R = \frac{-\ln(0.02)}{b_{ext}} = \frac{3.9}{b_{ext}} \qquad (1)$$

where b_{ext} is the extinction coefficient of the atmosphere, which is assumed to be homogeneous. The extinction coefficient in the denominator of the formula can be thought of as the fraction of light that is lost as it traverses 1 m of air. For completely clear air, b_{ext} has a value of about 10×10^{-6} m^{-1} or 10 Mm^{-1}, or a visual range of about 390 km. More typically, particles in the air usually increase the extinction coefficient to 150–300 Mm^{-1} or more. Typical visual ranges are about 10 km in the eastern United States and 50 km or more in the western United States. Closely related to b_{ext} and visual range is the more general concept of optical depth. For a target at a distance x, this is defined as xb_{ext}. It is dimensionless; if b_{ext} is held constant it represents distance, and if the distance is constant, it represents changes in b_{ext}. From eq 1, the visual range corresponds to an optical depth of 3.9, and a distance of about one quarter of the visual range is equivalent to an optical depth of 1.

Despite lacking a firm psychophysical or experimental basis, the visual range defined by the 2% threshold has stood the test of time. However, while visual range has proven to be a good surrogate for atmospheric visibility for the aviation community, it is of limited value in addressing the concerns of the air quality community. Unlike aviation, where poor visibility is of greatest interest, the air quality community is primarily concerned with relatively small changes in good visibility. Pitchford and Malm[2] have proposed the deciview as a visibility indicator more suited to air quality regulations. If the extinction coefficient is given in Mm^{-1}, then deciview is defined as

$$v = 10\ln(b_{ext}/10) \qquad (2)$$

Current regional haze visibility regulations state that:

(1) A 1-deciview change in haziness is a small, but noticeable, change in haziness under most circumstances when viewing scenes in Class I areas.

(2) Deciview units are uniform in perception over a wide range of visibility conditions; that is, a 1-deciview change is just perceptible regardless of the visibility conditions.[1]

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The next section describes a color matching experiment in the Great Smoky Mountains National Park. The results of this experiment are used to estimate a just-noticeable change in haze based on color perception. The validity of the claims for deciviews will be evaluated by comparison to experimental estimates of JNDs.

EXPERIMENTAL DATA

During summer 1995, a group of researchers from universities, government agencies, and private companies conducted the SouthEast Aerosol and Visibility Study (SEAVS) in the Great Smoky Mountains National Park. The SEAVS focused largely on aerosol composition,[5,6] airborne particle size distribution,[7,8] and the role of water in the aerosol.[9-11] However, the SEAVS had a number of other aspects, including a study of the perception of color through atmospheric haze.[12] The methods and primary results of the color perception study are described below.

The perceived colors of natural targets were quantified by color matching using a specially constructed visual colorimeter.[13] An observer looked at some scene element, such as a barn or green field, with one eye. The observer looked with the other eye in the visual colorimeter at a color spot, which the observer adjusted to match the color of the target. The perceived color was recorded as the amount of red, green, and blue light in the color match. At the same time, the spectrum of the light coming from the target was measured by a telespectroradiometer. A color appearance model was applied to produce measures of the perceived color as recorded by the visual colorimeter and as calculated from the spectrum.[14]

Of most interest here are the hue and colorfulness. The hue is what most people call the color—red, green, blue, yellow, and so on. It is quantified as a mixture of pure red, green, blue, or yellow lights. The colorfulness is the degree to which the hue is expressed; it is similar to the concept of saturation. A deep red color would have a colorfulness of about 100, while a colorfulness of 10 or less is almost achromatic (i.e., white or gray).

Two observers (Mahadev and Urquito) made color matches of a set of natural targets during the SEAVS. These observers were both males in their 20s with normal color vision. Each had received extensive training in color matching using the visual colorimeter. The scattering coefficient of the atmosphere was measured by a nearby nephelometer; particle absorption was small and its contribution to the extinction coefficient ignored. The full details of the experiment are found in Mahadev.[15]

The perception study found that viewing through a semitransparent atmosphere affected the perception of hue and colorfulness in a highly nonlinear way. The eye appeared to split the light coming from the target into two parts, the haze and the target. The result was that as the haze increased, the hue of the target as seen by the observer remained constant. However, because the increasing haze scattered more light into the sight path, the hue calculated from the spectrum became bluer. To the observer, the main effect of haze was to decrease the perceived colorfulness. Furthermore, the decrease in colorfulness seemed to be exponential with optical depth (optical depth is the dimensionless product of the extinction coefficient and distance):

$$M(\tau) = M_0 \exp(-\tau) \tag{3}$$

where $M(\tau)$ is the colorfulness of the object at optical depth τ and M_0 is the colorfulness at zero optical depth (i.e., no haze). M_0 is also known as the inherent colorfulness. The colorfulness of the horizon was assumed to be small enough to be taken as zero—the horizon was perceived to be white. This result implies that a JND in colorfulness can be taken to be a JND in haze.

JND in Colorfulness

Estimates of JNDs in colorfulness were based on sets of repeated color matches made during periods when the observing conditions (cloud cover, haze level, and lighting) were judged to be constant or nearly so. Observer Urquito made six sets of repeated matches.[15] Figure 1 is a plot of all the repeated observations of the colorfulness of the red barn roof made by this observer versus optical depth. The exponential fit given by eq 1 is fairly good ($R^2 = 0.68$). The error bars in the figure are twice the standard deviation given in Table 1. They show that one set

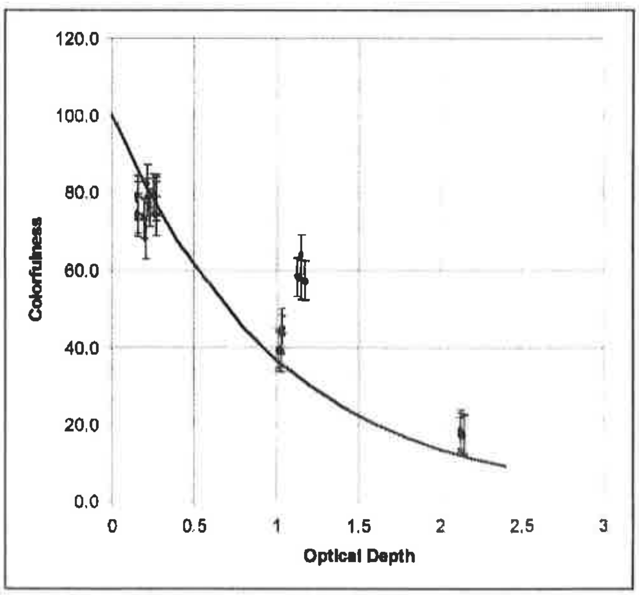

Figure 1. Colorfulness vs. optical depth for observer Urquito for repeated observations of the red barn roof. The line is an exponential fit as in eq 1, and the error bars are two times the standard deviation given in Table 2.

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Table 1. Repeated measurements of the red barn roof by observer Mahadev.

Date	Time	Scattering Coefficient $(Mm)^{-1}$	Visual Range (km)	Colorfulness Spectra	Colorfulness Perceived	Spectra Hue % Red	Spectra Hue % Blue	Perceived Hue % Red	Perceived Hue % Blue
7/29/95	10:20 a.m.	37	105.7	38.0	42.2	53	47	97	3
7/29/95	10:46 a.m.	39	100.3	38.9	45.6	40	60	92	8
7/29/95	10:54 a.m.	39	100.3	39.9	45.4	38	62	99	1
7/29/95	11:03 a.m.	42	93.1	35.6	46.3	52	48	92	8
7/29/95	11:12 a.m.	42	93.1	37.5	44.9	53	47	93	7
7/25/95	11:49 a.m.	65	60.2	31.2	41.1	50	50	88	12
7/25/95	12:01 p.m.	65	60.2	30.8	45.1	42	58	84	16
7/25/95	12:12 p.m.	65	60.2	30.4	44.1	53	47	91	9
7/25/95	12:19 p.m.	65	60.2	29.4	43.0	54	46	91	9
7/25/95	12:24 p.m.	65	60.2	29.2	48.4	47	53	93	7
8/11/95	9:46 a.m.	157	24.9	37.6	29.2	19	81	97	3
8/11/95	9:57 a.m.	157	24.9	37.2	28.8	22	78	98	2
8/11/95	10:07 a.m.	157	24.9	37.5	29.2	23	77	98	2
8/11/95	10:16 a.m.	161	24.3	36.3	34.9	24	76	98	2
8/11/95	10:21 a.m.	161	24.3	36.7	29.5	23	77	98	2
8/14/95	10:12 a.m.	311	12.6	44.4	18.2	9	91	91	9
8/14/95	10:18 a.m.	312	12.5	44.0	18.4	8	92	97	3
8/14/95	10:30 a.m.	313	12.5	44.8	17.6	7	93	95	5
8/14/95	10:34 a.m.	313	12.5	44.7	18.1	7	93	94	6
8/14/95	10:38 a.m.	313	12.5	44.3	18.3	8	92	94	6
8/18/95	11:00 a.m.	595	6.6	35.3	9.7	2	98	81	19
8/18/95	10:46 a.m.	616	6.4	35.4	6.8	2	98	98	2
8/18/95	10:50 a.m.	616	6.4	35.2	9.4	2	98	91	9
8/18/95	10:53 a.m.	616	6.4	35.0	7.3	2	98	99	1
8/18/95	10:57 a.m.	616	6.4	35.7	10.0	2	98	97	3

of repeated measurements had colorfulness values that deviated much more than 2 sigma from the exponential line. However, the spread of these values about the mean was about the same as other observations for the same optical depth. This shows that the variability in the colorfulness numbers is not affected by systematic observer bias in the average colorfulness, and that the variability will be used to define the JND. The observations of the same target by the other observer are discussed in detail below.

Table 1 gives the results of five sets of repeated matches by observer Mahadev for the roof of a red barn about 3.5 km distant. Table 1 is sorted by the extinction coefficient so that one can easily see that the perceived hue did not change with increasing haze, but that the hue derived from the spectrum changed from red to blue. Colorfulness had the opposite behavior; the perceived values decreased with increasing haze and the values from the spectrum stayed about the same. Two-way analysis of variance was applied to estimate the random error in the sets of repeated measurements in Table 1. This analysis was repeated for both observers' matches of five additional natural targets. The results are given in Table 2. The standard deviation for both observers was 2.05, as calculated from the average of the variances. Although viewing conditions were chosen to be constant, some of this variability was due to small changes in atmospheric conditions.

Based on these results, one can define the JND in colorfulness in many ways. One appropriate definition for this application is based on the following thought experiment. An observer matches a target with the visual colorimeter and determines the colorfulness to be C_1. The extinction coefficient of the atmosphere is decreased, so the colorfulness of the target is increased by an amount ΔC. The observer matches the target again to get the new colorfulness C_2. A JND is defined as the value of ΔC that gives a 95% probability that $C_2 - C_1 > 0$. Assume that C_1 and C_2 are normal random variables with standard deviation s and means C_0 and $C_0 + \Delta C$, respectively (statistical analysis of the SEAVS color matching data confirms that this is a good assumption). Then $C_2 - C_1$ is a normal random variable with mean ΔC and standard deviation $2^{1/2}\sigma$. The value of ΔC needed to ensure a 95% probability that $C_1 - C_2 > 0$ is given by $2^{1/2}\sigma F(0.95)$, where $F(0.95)$ is the inverse of the cumulative standard normal distribution and is equal to 1.645. Thus, the colorfulness JND is taken to be $2^{1/2}\sigma F(0.95) = 2.326\sigma$. From Table 2, using the data for both observers gives $\sigma = 2.05$, and a 1 colorfulness JND is 4.8. This value of σ includes the effects of small random variations in natural illumination, which should be included for this application because they are inevitably present, but makes the value of a colorfulness JND a bit larger than it would be otherwise.

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Table 2. Standard deviations of colorfulness for repeated matches of natural targets.

Target	Observer M	Observer U	Distance (km)
White silo	0.91	1.33	3.54
Red roof	1.93	2.41	3.54
Near green meadow	2.93	2.15	3.86
Green hills	2.15	3.46	5.15
Far green meadow	1.45	1.64	10.46
Horizon sky	1.53	1.19	
Average	1.92	2.17	
Number of observations	55	60	

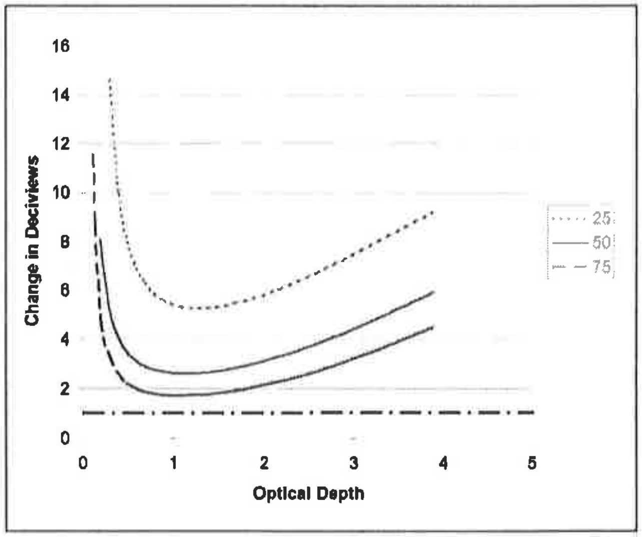

Figure 2. Change in deciviews needed to produce a just-noticeable increase in colorfulness for objects with an inherent colorfulness of 25, 50, and 75. The horizontal dashed dotted line represents what would be expected if a 1-deciview change were actually a uniform measure of haze perception.

Deciviews and Colorfulness JNDs

Relationships between colorfulness, deciviews, and optical depth are derived below; these will be applied to test the validity of the properties of deciviews given in the regional haze regulations.

From eqs 2 and 3, an expression for deciviews v as a function of colorfulness M is derived:

$$v = 10\ln\left(-\frac{1}{10x}\ln\left(\frac{M}{M_0}\right)\right) \quad (4)$$

For a given optical depth and inherent colorfulness, the equations above were used to calculate the change in deciviews needed to give a 1-JND increase in colorfulness, using 4.8 as a JND. Figure 2 is a plot of the results as a function of optical depth for objects with three levels of inherent colorfulness. These levels of inherent colorfulness represent a reasonable range for natural targets.[12] As might be expected, more colorful objects are more sensitive to changes in atmospheric haze. Perhaps unexpectedly, the figure shows that landscape features at a distance corresponding to an optical depth of 1–2 are the most sensitive to changes in extinction as measured by deciviews. This range corresponds to one quarter to one half of the visual range. Landscape features outside this range are much less sensitive to changes in haze. If the deciview scale were perceptually uniform, as claimed in the regional haze rules, then the lines in the figure would be horizontal, or at least approximately so. However, the change in deciviews needed to produce a 1-JND change in colorfulness varied a great deal with optical depth and inherent colorfulness. The figure also shows that a 1-JND change in colorfulness always requires more than a 1-deciview change, sometimes much more.

DISCUSSION AND CONCLUSIONS

Regional atmospheric haze affects visibility by producing a visible haze layer that limits the visual range, reduces contrast, and deceases the colorfulness of objects seen though the haze. Of these three effects of haze, the decrease in colorfulness may be the most important and sensitive visual cue. Visual range is not often useful for judging the effects of small changes in extinction. For example, a change in visual range from 50 to 60 km will not be noticed if the most distant landscape feature is at 25 km. The effect of haze on contrast is a better candidate as an indicator of change in haze; however, perceived contrast, like perceived hue, is affected in a nonlinear fashion by the semitransparent nature of haze and is not a sensitive indicator of changes in atmospheric haze.[16] Experimental data have shown that colorfulness is a sensitive measure of changes in haze, so this article has used it to define just-noticeable changes in atmospheric haze.

A just-noticeable decrease in atmospheric haze is defined as a decrease in extinction that would produce a 95% probability of a measurable increase in colorfulness of an object seen through the haze. From the experimental evidence from the two young male observers, a JND in colorfulness was 4.8. For the population in general, this number is certainly too low, since all visual functions decline with age. Thus, the conclusions below about the deciview scale based on this number are understated for the general population.

Analysis of the experimental data showed that for a JND in atmospheric haze as defined above:

(1) The deciview scale is not uniform in perception over a wide range of visibility conditions. In fact, the change in deciviews needed to be noticeable

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varies greatly depending on the optical distance of the landscape feature and its inherent colorfulness.

(2) A 1-deciview change is never noticeable.

What are the implications of these results for measuring progress toward reducing regional haze using the deciview metric? This is difficult to judge because the current proposals are very complex, using particulate measurements and relative humidity to estimate the extinction coefficient and average deciviews for the 20% most-impaired and 20% least-impaired days. The goal is to show no change on the least-impaired days and improvement on the most-impaired days, leading to natural conditions by 2064.[17]

The results of this article highlight a possible flaw in this regulatory scheme based on the deciview metric. An unstated assumption is that the nature of the scenic vista can be ignored—that is, a given deciview change will affect the perception of all landscape features in all scenes in the same way. Figure 2 shows that this is approximately true only if all the important landscape features have nearly the same inherent colorfulness and are at distances that correspond to an optical depth of between 1 and 2, or about one quarter to one half of the visual range. In this limited case, the deciview is indeed a uniform metric. However, most scenic vistas do not fit these restrictions and, by Figure 2, will require greater decreases in extinction as measured by deciviews to show a perceptible change. The result is that the emission reductions required by the proposed regulatory analysis are likely to produce much smaller improvements in perceived effects of regional haze than expected. The EPA guidance documents provide an example of an eastern scenic vista with a baseline of 27 deciviews and natural conditions of 11.[17] The decrease in extinction to reach natural conditions by 2064 is 0.35 deciview/yr, or 1.75 deciviews in five years. This five-year reduction should, according to the regulations, result in a noticeable change in regional haze. However, the results herein predict that there would very likely be no noticeable difference in any actual scenic vista in the region as a result of the required emission reductions.

Regional haze rules also call for a uniform rate of improvement in visibility (measured in deciviews) that is needed to go from current conditions to natural conditions by 2064. Since the deciview scale is not uniform in perception over a wide range of visibility conditions, this requirement is also flawed and will not result in uniform improvement in perceived visibility.

ACKNOWLEDGMENTS

The funding for this project was provided by the Electric Power Research Institute under Contract EP-P5419/C2683. The author would like to thank Dr. Naresh Kumar for his support and discussions leading to this work, and Drs. Shudeish Mahadev and Santiago Urquito for their careful and diligent work as the observers in the field study.

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Exhibit E to EAI Comments

FOSTER WHEELER NORTH AMERICA CORP
53 Frontage Road,
Hampton, NJ 08827-9000, USA

TANGENTIAL LOW NOx (TLN3) SYSTEM

FOR

ENTERGY
WHITE BLUFF UNITS 1& 2

Proposal No. 65-130582-00 Rev. 0
October 13, 2011

PROPIETARY AND CONFIDENTIAL INFORMATION

This proposal and the information, design and material contained and/or illustrated herein (hereinafter "proprietary and confidential" material), are the property of FOSTER WHEELER NORTH AMERICA CORP, (FWNAC) and is submitted, lent and furnished to you in the strict confidence with the expressed understanding that you shall not use said proprietary material for any purpose other than for the evaluation of this proposal or reproduce, copy, lend, dispose of, or disclose said proprietary material to anyone outside receipt organization. By receiving said proprietary material you agree not to use the same in any way injurious to the interest of FOSTER WHEELER NORTH AMERICA CORP, and agree to return to same upon request.

3.3 Foster Wheeler's Tangential Low NOx (TLN) Systems

3.3.1 Design Philosophy

Foster Wheeler North America Corp's (FWNAC) Tangential Low NOx (TLN) Combustion Systems provide industrial and utility boiler owners with an alternative solution to their NOx compliance needs. Our philosophy is to provide our clients with the highest value low NOx system.

- Our systems are designed to maximize NOx reduction efficiency while minimizing the impact on combustion performance or unit operation. An extensive support team of experienced technical and project specialists backs our commitment.

- We focus on designing systems that minimize changes to the furnace and / or the boiler house. This reduces installation time and costs for the owner.

- We believe each TLN application should complement the unit's operational capabilities as well as the range of current and future fuels.

- We believe that each TLN system should provide years of reliable service. All T-fired windbox components are manufactured in either our own facilities or per our specifications by high quality suppliers.

- A team of experienced and qualified tangential firing engineers, project managers, service engineers and suppliers supports each project. Our goal is to make each of your TLN retrofits your most favorable project.

Our system technology is supported by a continuous commitment to improve performance and reliability. For example our on-line real-time, ECT coal flow distribution, velocity and particle size monitoring technology combined with our CADM system allows fuel and air to be more balanced for lower CO and higher combustion efficiency.

Currently there are numerous tangentially coal fired utility units equipped with Foster Wheeler's TLN systems (see Experience List in Appendix). Fuels being fired range from lignite and PRB through low and higher sulfur eastern bituminous coals. NOx reductions exceeding 70 percent and NOx levels below 0.10 lb/MBtu are being achieved.

3.3.2 FWNAC's TLN Systems

Foster Wheeler's Tangential Low NOx (TLN) firing systems are based on the application of secondary air staging technology commonly referred to as "overfire air". Both in-windbox and separated secondary air-staging arrangements are applied depending on current windbox configurations and the desired level of NOx reduction. Staging of secondary combustion air has been well documented throughout the international boiler industry to be the single most effective technique for reducing NOx emissions from tangentially fired boilers. By redirecting a portion of the combustion air above the upper fuel elevation, fuel nitrogen conversion and thermal NOx production is reduced. Control of this staging process through proper nozzle and damper design is critical in order to maximize combustion efficiency and component longevity. Depending on the unit configuration and required NOx reductions, Foster Wheeler can offer several high value options. These include the TLN1, TLN2 and TLN3 arrangements, which are shown below in **Figure 3.**

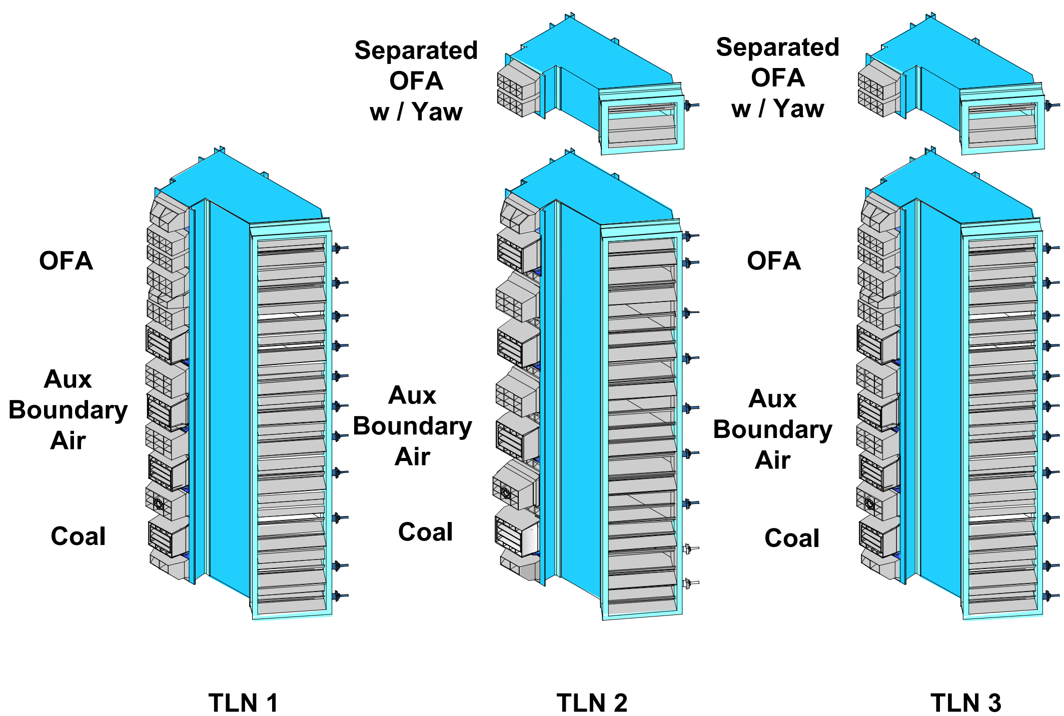

Figure 3 - FWNAC Tangential Low NOx (TLN) Configurations

Foster Wheeler's **TLN2** system consists of adding a single level of separated overfire air above the main firing zone to provide the required vertical air staging effect. Due to increased spacing from the upper coal elevation, separated overfire arrangements provide significantly higher NOx reduction efficiencies as compared with "in-windbox" arrangements. Nozzle tips and/or air flow control dampers in the main windboxes are often resized or modified as part of such retrofits. Foster Wheeler's proprietary computer-modeling program is used to ensure that proper airflow distribution control and air/coal mixing is maintained throughout the unit load range with the new SOFA addition.

The **TLN3** system consists of adding a single level of separated overfire air to units that already have an in-windbox OFA. Other applications of the TLN3 arrangements are units where interferences do not permit placement of an adequate single overfire air windbox level. Nozzle tips and air flow control dampers in the main windboxes are often upgraded or modified in accordance with computer modeling results or to meet specific unit or fuel requirements. These modifications ensure that proper airflow distribution control and air/coal mixing is maintained. Both the TLN2 and TLN3 have demonstrated up to 75% NOx reduction.

3.3.3 Combustion Computational Fluid Dynamics - Option

Foster Wheeler is offering a Computational Fluid Dynamics (CFD) study of furnace thermodynamics to validate boiler performance before and after installation of the SOFA system. CFD analysis is an inherently man-hour intensive process because the ability of the CFD model to provide accurate predictions is predicated on the accuracy of the model and thus requires that each existing system (boiler) be manually detailed in the program prior to use. CFD can therefore be a somewhat expensive undertaking.

FWNAC feels obligated to inform Entergy that the results of CFD modeling have never altered the design, predictions or guarantees associated with a TLN retrofit and can therefore be somewhat of an extraneous exercise unless applied to validate a specific, unique design feature. In other words, should Entergy find the cost/benefit associated with use of CFD to be less than satisfactory, solace should be found in the fact that it will only service to confirm the design being offered.

Should Entergy desire to proceed with use of Foster Wheeler's Combustion CFD program, on both White Bluff units, the model will extend from the burner fronts up through the leading edge of the first bank of the finishing superheater.

Vital to any OFA design is full penetration of the air jets into the furnace gas stream to insure turbulent mixing with the bulk of the rising flue gases. This is accomplished by choosing appropriate nozzle velocities and sizes. Foster Wheeler has studied jet

4 DESCRIPTION OF PROPOSED FWNAC TLN3 SYSTEM

4.1 Proposed TLN3 System for White Bluff Units 1 and 2

Based on Entergy's requirements and FWNAC's evaluation of the current unit operation, FWNAC is proposing our TLN3 system. This system will consist of the following specific components and features.

The proposed FWNAC modifications to Entergy's White Bluff Units 1 and 2 are shown on FWNAC proposal drawings attached in the Appendix.

a) A SINGLE level of new separated SOFA windboxes will be provided as part of the FWNAC TLN3 system. This would consist of eight (8) new SOFA windboxes. To minimize physical changes to the boiler house, the new Overfire Air windboxes would be installed in the front and rear walls above the existing windboxes. The SOFA windboxes would be designed to supply the appropriate amount of combustion air as Overfire Air. Each new windbox will be provided along with new water wall panels and the necessary connecting ductwork, hangers, expansion joints and steel modifications to interface with the secondary air ducts. Each windbox will be fitted with nozzle tips, turning vanes, access doors, air control dampers with actuators (Kinetrol 147-130-1900 Fail Open Spring return Actuator with Siemens PS2 Single Acting Smart Positioner) and static pressure taps to provide total Overfire Air control. Manual "set and forget" horizontal yaw and vertical tilt capability would be provided in the SOFA to help control CO as well as back end gas temperature and oxygen profiles. The yaw linkage, manual tilt gearbox and damper drives will be accessible from the sides of each windbox.

   A CFD air flow model will be developed that includes the secondary air ducts, SOFA ducts, windboxes and burners to ensure balanced air flow.

b) Platform, railing, sootblowers, and sootblower piping may need to be modified where required to accommodate the addition of the separated over fire air system.

c) New FW Double Shroud (DS) type nozzle tips and associated linkage hardware will be supplied. These will be 100% compatible with the existing coal nozzle and tilt linkage. The new nozzle tip, which includes a patented (US Patent No. 6,260,491) cooling feature, will also be reconfigured to further help stage more air to the SOFA compartments to provide additional NOx reduction benefits.

d) The 23¼ inch high upper CCOFA compartment will be modified with a crotch cooling plate on the top and a restrictor plate on the bottom to reduce the outlet height to 19 ¼ inches. A new, one piece FWNAC DS style nozzle tip will be provided. This tip will be the same tip as the lower CCOFA and bottom air tips. This interchangeability will reduce stocking and maintenance costs.

e) The 23¼ inch high lower CCOFA compartment will be fitted with restrictor plates and a new DS style nozzle tip exactly like the upper CCOFA nozzle tip.

f) The fuel piping to the refuse compartment is currently blanked off, with no future plans for firing this compartment. As a top end air, this 24 inch high compartment will be fitted with restrictor plates and a new DS style nozzle tip exactly like the CCOFA nozzles.

g) The outlet flow area of each 27¼ inch high auxiliary air compartment will be reduced with restrictor plates for velocity compensation. Each compartment will be fitted with one (1) new, one piece FWNAC DS style type boundary air auxiliary nozzle tip. The nozzle tip is designed to provide the necessary velocity, air flow distribution and direction control to benefit NOx emissions and fireball shaping while maximizing combustion efficiency.

h) The 27¼ inch high oil warm-up compartment will also be reduced with restrictor plates for velocity compensation and modified with a similar tip, with the center of the tip to accommodate the existing oil gun. However, due to the presence of the oil warm-up gun, this tip will not yaw.

i) The existing bottom end air compartments will be fitted with new, one piece reduced free area nozzle tips. These tips will be interchangeable with the CCOFA tips.

j) As an integral part of the TLN3 system, the Lower Furnace Stoichiometry Control (LFSC) system will be provided. These systems help reduce the dark lower furnace hopper conditions typically associated with deep-staged combustion systems. It is comprised of a single air nozzle tip with external manual tilt installed in the bottom end air compartment. This will be used to direct combustion air into the lower furnace hopper area, further controlling lower furnace smoky conditions, slagging and CO formation that might occur during ultra low NOx deep staged operation.

k) All coal, auxiliary air and CCOFA windbox compartments will be modified with FWNAC's damper venturi plates to improve air flow distribution control over a larger load range.

7 PERFORMANCE GUARANTEES & CONDITIONS

7.1 Performance Guarantees

The following Performance Guarantees contained within this section 7.1 are the **exclusive performance guarantees** offered by FWNAC relating to the equipment supplied by FWNAC. Any graphs, stated performance values, predictions or discussions in other sections of the proposal or in the specification fill-in sheets shall not be construed as performance guarantees.

- Three (3) one hour tests will be conducted for NOx, CO, LOI, main steam temperature and reheat steam temperature at MCR. Three (3) one hour tests will also be conducted for main and reheat steam temperatures at Guarantee Point Load and Control Load. The guarantees will be considered met if the average of each guarantee value over the three (3) test periods meets the guarantee values offered below by FWNAC.

  A thirty (30) day rolling average test will also be conducted for NOx and CO emissions. This test may be conducted for 45 day period to allow for selection of the data for the 30 day period. Only data to be included will be that while the unit is operating between Control Load and MCR. Data will be excluded while the unit is at upset condition.

- All performance conditions, test methods, and referenced fuels/ranges of fuels as defined in Section 7.2 of this proposal are considered a prerequisite for the guarantees. All sampling must ensure that a representative average of the flue gas emissions and fly ash sample is taken.

7.1.1 NOx Emissions

<u>MCR (6,023 klb/hr main steam flow)</u>

- **NOx will average less than or equal to 0.12 lb/MBtu for the average of three (3) one hour tests**

<u>Control Load (3,000 klb/hr main steam flow) to MCR (6,023 klb/hr main steam flow)</u>

- **NOx will average less than or equal to 0.14 lb/MBtu over a 30 day period**

7.1.2 Carbon Monoxide (CO)

MCR (6,023 klb/hr main steam flow)

- **CO will average less than or equal to 0.15 lb/MBtu (185 ppm measured at 3.0% O2 dry) for the average of three (3) one hour tests**

Control Load (3,000 klb/hr main steam flow) to MCR (6,023 klb/hr main steam flow)

- **CO will average less than or equal to 0.15 lb/MBtu (185 ppm measured at 3.0% O2 dry) over a 30 day period**

7.1.3 Fly Ash LOI

MCR (6,023 klb/hr main steam flow)

- **Fly ash LOI will average less than or equal to 1.0% for the average of three (3) one hour tests**

7.1.4 Superheat (SH) Steam Temperatures

MCR (6,023 klb/hr main steam flow)

- **980 ±10°F** for the average of three (3) one hour tests

Guarantee Point (5,400 klb/hr main steam flow)

- **980 ±10°F** for the average of three (3) one hour tests

Control Load (3,000 klb/hr main steam flow)

- **980 ±10°F** for the average of three (3) one hour tests

7.1.5 Reheat (RH) Steam Temperatures

MCR (6,023 klb/hr main steam flow)

- **1000 ±10°F** for the average of three (3) one hour tests

Guarantee Point (5,400 klb/hr main steam flow)

July 30, 2015
Ref: Tangential Low NOx

Michael P. Fallon, P.E.
Entergy – Boiler Process Owner
White Bluff & Lake Catherine

Dear Mike;

Tangential low NOx systems that use separated overfire air are designed to provide significant reductions in NOx across the control range of the boiler, which is normally from 50 to 100 percent of steam flow. These systems work in the control range because the heat input across this range is sufficient to safely redirect a substantial portion of combustion air through the overfire air registers. When this is done combustion zone airflow is sub stoichiometric and oxygen there is reduced to the point where much of the elemental nitrogen in the fuel and combustion air can pass through the boiler without oxidizing.

Overfire air cannot be fully utilized for NOx abatement below the control range because net heat input is not sufficient to allow the combustion zone in the furnace to safely run in a sub stoichiometric condition. When a boiler runs below the control range NOx concentrations can be elevated above the levels achievable at higher loads, even though the tons of NOx emitted is less due to the reduced amount of fuel and air.

I hope this memo answers your question.

Steve deMello
Project Manager
Amec Foster Wheeler North America Corp.
53 Frontage Road, PO Box 9000
Hampton, NJ 08827-9000

EVALUATION OF THE CALPUFF MODELING SYSTEM MARGIN OF ERROR FOR A BART ANALYSIS

Entergy Arkansas, Inc. > Lake Catherine Plant

Prepared By:

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August 4, 2015

Project 154401.0074

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Exhibit H to EAI Comments

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1. EXECUTIVE SUMMARY

On April 8, 2015, the United States Environmental Protection Agency (EPA) published the Arkansas Regional Haze Federal Implementation Plan (FIP) to address regional haze and visibility transport requirements for the State of Arkansas. As part of the FIP, EPA proposed nitrogen oxide (NO_X) controls for the Entergy Arkansas, Inc. (Entergy) Lake Catherine Plant Unit 4, which is subject to Best Available Retrofit Technology (BART).[1] In order to justify the visibility improvement as a result of installation of the proposed controls, EPA relied on the CALPUFF dispersion modeling system (CALPUFF) without assessing the reliability of the model to predict small changes in visibility.

Entergy completed a quantitative analysis to evaluate the margin of error in the CALPUFF analysis for Lake Catherine Unit 4 and determined the visibility improvements relied upon in the proposed Arkansas FIP are within the model's margin of error. Specifically, the incremental visibility improvements predicted by CALPUFF at the Caney Creek Wilderness Area (Caney Creek) and Upper Buffalo Wilderness Area (Upper Buffalo) Class I areas are within the margins of error calculated for each Class I area. Moreover, the visibility improvement values are within the *lowest* margin of error for both Class I areas. Because of this, EPA cannot *reasonably anticipate* visibility benefits from the proposed controls for Lake Catherine Unit 4. *See National Parks Conservation Ass'n v. EPA*, 788 F.3d 1134, 1146–47 (9th Cir. 2015) ("Montana Case") (holding that EPA must offer a reasoned explanation of its conclusion that a visibility improvement could be reasonably anticipated when the improvement is within CALPUFF's margin of error).

This report is organized as follows: Section 2 provides background on the Lake Catherine Plant and EPA's proposed BART requirements, Section 3 outlines the methodology used in the Lake Catherine analysis, Section 4 summarizes the results of the analysis, and Section 5 presents several case studies comparing modeled values to monitored values.

---

[1] Proposed Arkansas Regional Haze FIP, 80 Fed. Reg. 18,943 (Apr. 8, 2015).

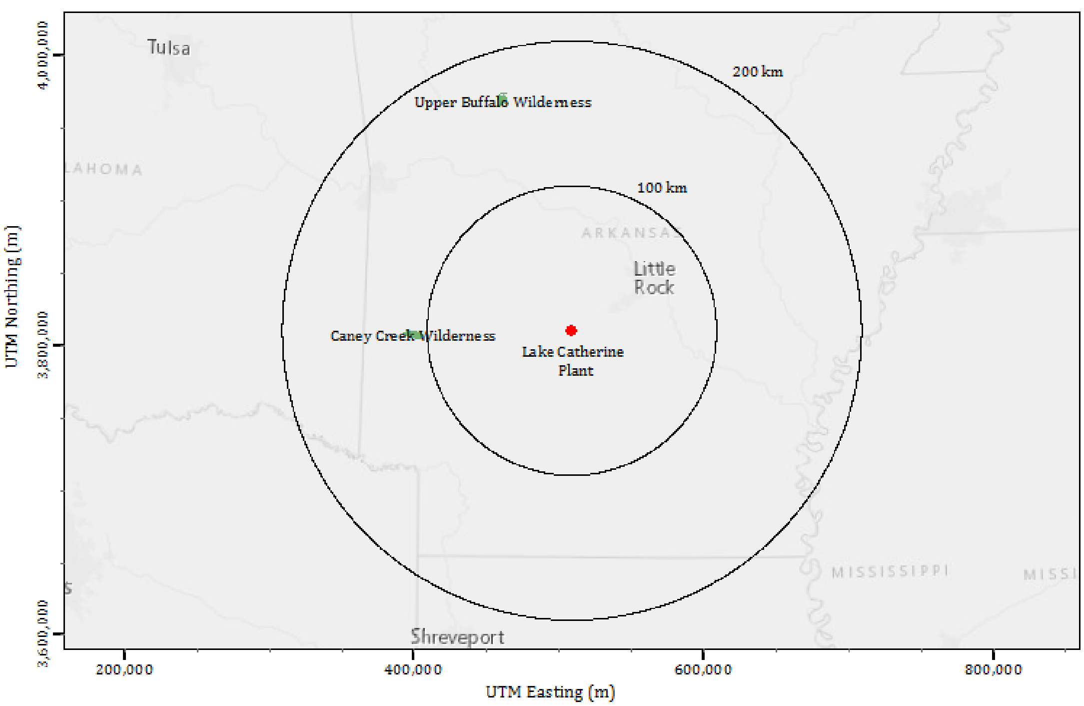
Entergy owns and operates the Lake Catherine Plant located at 141 W. County Line Road in Malvern, Arkansas. The Lake Catherine Plant operates one emission unit – Unit 4 – that is an affected source under the BART provisions of the EPA's Regional Haze Rule, which is codified in Title 40 of the Code of Federal Regulations (40 CFR) Part 51. Unit 4 is a tangentially-fired boiler with a nominal heat input rate of 5,850 Million British thermal units per hour (MMBtu/hr) and a nominal net power rating of 558 megawatts (MW). The boiler is permitted to fire natural gas and No. 6 fuel oil; however, the unit has not fired fuel oil since the 2001-2003 baseline period and Entergy does not plan to burn fuel oil in the unit in the foreseeable future.

On April 18, 2015, EPA proposed a FIP to address requirements related to regional haze for those portions of the Arkansas State Implementation Plan (SIP) that were disapproved on March 12, 2012.[2] The FIP includes NO_X BART requirements for Lake Catherine Unit 4.

2.1. CLASS I AREAS

Per the FIP, there are two (2) Class I areas in Arkansas that are impacted by Unit 4 at the Lake Catherine Plant: Caney Creek and Upper Buffalo. Caney Creek is approximately 100 km west and Upper Buffalo is approximately 160 km north of the Lake Catherine Plant. The locations of the Class I areas with respect to the Lake Catherine Plant are shown in Figure 2-1 below. Table 2-1 summarizes the baseline visibility impairment attributable to Unit 4 at each of these Class I areas as determined by CALPUFF.[3]

Figure 2-1. Location of Lake Catherine Plant with Respect to Arkansas Class I Areas



[2] FR Vol. 80, No. 84, May 1, 2015.

[3] Ibid.

Table 2-1. Baseline Visibility Impairment

Emission Unit		Caney Creek	Upper Buffalo
Unit 4	Maximum (Δdv)[1]	3.480	2.044
	98^{th} Percentile(Δdv)[1]	1.371	0.489

1. Values shown are for natural gas combustion.

2.2. PROPOSED BART FOR THE LAKE CATHERINE PLANT

The proposed NO_X BART for Lake Catherine Unit 4 is summarized below.

2.2.1. NO_X BART

In the proposed FIP, EPA determined that NO_X BART for Unit 4 for the natural gas scenario is an emission limit of 0.22 pounds per MMBtu (lb/MMBtu) on a 30 boiler-operating-day rolling averaging basis, based on the installation and operation of Burners out of Service (BOOS).[4] The projected visibility improvement at Caney Creek and Upper Buffalo based on CALPUFF modeling is shown in Table 2-2 below.

Table 2-2. Projected Visibility Improvement

Emission Unit	Pollutant	Caney Creek (Δdv)	Upper Buffalo (Δdv)
Unit 4	NO_X	0.596	0.248

[4] Per the FIP, "BOOS is a staged combustion technique in which fuel is introduced through operational burners in the lower furnace zone to create fuel-rich conditions, while not introducing fuel to other burners."

In completing the BART five factor analysis for Lake Catherine Unit 4, EPA relied on the visibility improvement as predicted by CALPUFF without assessing the ability of the model to accurately predict small changes in visibility. In order to assess the magnitude of visibility that could reasonably be anticipated for the Lake Catherine case, Trinity conducted a margin of error analysis similar to the one completed for the Colstrip Generating Station ("Colstrip Station") by TRC Environmental Corporation (TRC) that was the basis for PPL Montana's comments on the CALPUFF model in the Montana Case.[5] The following sections outline the methodology that was used to complete this analysis for the Lake Catherine Plant. This study is necessary due to the dissimilarities in the geographical and meteorological conditions between the Lake Catherine Plant and the Colstrip Station at issue in the Montana Case.

3.1. MODEL SELECTION

The BART Guidelines recommend using the CALPUFF Modeling System to determine the visibility impairment attributable to a BART-eligible source. This analysis was completed using CALPUFF Version 5.84, POSTUTIL Version 1.52, and CALPOST Version 6.221, the model versions utilized in the Arkansas BART analyses. Entergy used refined meteorological data consistent with the meteorological data used for other BART sources in Arkansas. On July 26, 2012, the Arkansas Department of Environmental Quality (ADEQ) updated its original (June 7, 2006) protocol including CALPUFF modeling components and the background concentrations in CALPOST. The CALMET data and parameters are based on the modeling protocol that was first submitted on January 23, 2008 on behalf of Oklahoma Gas & Electric and upon which all recent BART analysis in Arkansas have been based. This protocol summarizes modeling methods and procedures that were followed to predict visibility impairment for several BART-eligible sources located in Oklahoma as part of the BART analyses for these sources.

3.2. MODELED SCENARIOS

As part of this analysis Entergy modeled the following three scenarios:

1. ALL BART: Includes all sources subject to BART modeled using Pre-BART representations;
2. Pre-BART: Includes only the Lake Catherine Plant BART eligible source modeled based on its current permit representations; and
3. Post-BART: Includes only the Lake Catherine Plant BART eligible source modeled using the Post-BART emission rate and stack parameters.

3.3. BACKGROUND VALUES

The primary objective of this analysis was to compare the model predicted data to monitored data at each Class I area to identify the modeling margin of error in predicting visibility compared to observed values. BART modeling using CALPUFF is conducted to determine the impact of a facility on a Class I area without consideration of emissions/impacts from other sources. This type of analysis uses only natural background

[5] *See* "Accuracy of Visibility Protocol Modeling in BART Evaluations" prepared by Gale F. Hoffnagle, TRC Environmental Corporation, June 15, 2012. PPL Montana relied on this analysis in its comments alleging that the incremental visibility improvement predicted by EPA at Colstrip Station were within CALPUFF's margin of error. *See* PPL Montana, LLC's Comments on Proposed Regional Haze Federal Implementation Plan for the State of Montana at 8–11, Docket ID EPA-R08-OAR-2011-0851-0211 (2012).

conditions, referred to by EPA as a "clean background" analysis. As such, comparing model predicted output directly from the CALPUFF Modeling System to monitoring data does not represent a like-kind comparison as it is missing contribution from other sources. In order to obtain an estimate of the impact of other emission sources (i.e., point, non-point, mobile, biogenic, etc.), Entergy obtained a background value from CAMx modeling completed for the Central Regional Air Planning Association (CENRAP) by ENVIRON using the CENRAP PM Source Apportionment Technology (PSAT) Tool.[6] The CENRAP's CAMx analysis was completed for actual emissions from 2002; therefore, the background value from 2002 was added to the CALPUFF predicted impacts for all modeling scenarios and compared to 2002 IMPROVE data for Caney Creek and Upper Buffalo.

3.4. MODELED VERSUS MEASURED STATISTICS AND MARGIN OF ERROR

Entergy calculated the average difference between modeled values obtained using the CALPUFF Modeling System (including the CENRAP background) and IMPROVE monitored values for Caney Creek and Upper Buffalo for each of the three (3) modeling scenarios described previously. Unlike BART analyses where the 98th percentile values are compared to the dv impact level, Entergy utilized the regional haze design value format of average worst 20% days for this analysis. Since the CENRAP background value is from the 2002 calendar year, this comparison was only completed for 2002. Specifically the following comparisons were made:

> Modeled vs Measured 20% Worst Days: The worst 20% days based on IMPROVE measurements were selected for each Class I area and compared with the CALPUFF results from the corresponding days.

> Measured vs. Modeled 20% Worst Days: The worst 20% days based on CALPUFF modeling results were selected considering only days when IMPROVE measurements were taken. Modeled values were then compared to the IMPROVE measurements from the corresponding days.

> Measured and Modeled 20% Worst Days: The worst 20% days based on IMPROVE measurements were selected and compared with the worst 20% days based on CALPUFF modeling results disregarding temporal correlation.

Entergy used these average differences to determine the lowest overall margin of error for each Class I area. Entergy also examined how the modeled visibility impacts from the Lake Catherine Pre-BART scenario, excluding background, compared with the IMPROVE measurements at Caney Creek and Upper Buffalo. This provides an indication of the magnitude of the contribution from Lake Catherine Unit 4 to the total visibility impairment reflected in the IMPROVE measurements.

[6] See the CENRAP TSD and the August 27, 2007 CENRAP PSAT tool - CENRAP_PSAT_Tool_ENVIRON_Aug27_2007.mdb

The following sections summarize the results of the analyses completed for the Lake Catherine Plant.

4.1. MODELED VERSUS MEASURED STATISTICS AND MARGIN OF ERROR

Table 4-1 below summarizes the average difference between the modeled versus measured 20% worst days (20% worst-days based on measured values), measured versus modeled 20% worst days (20% worst-days selected based on modeled values), and modeled and measured 20% worst days (comparison of values from 20% worst modeled days and 20% worst measured days not temporally paired). Consistent with the study assessing CALPUFF modeling for the Colstrip Station, CALPUFF consistently over predicts when compared to IMPROVE observations.

Table 4-1. Summary of Modeled Versus Measured Statistics

Model Scenario	Modeled vs. Measured Statistics	CACR (Mm-1)	CACR (dv)	UPBU (Mm-1)	UPBU (dv)
All BART Sources	Modeled vs. Measured 20% Worst Days Average Difference	28.69	1.40	22.18	1.09
	Measured vs. Modeled 20% Worst Days Average Difference	45.64	6.47	51.65	6.09
	Modeled & Measured 20% Worst Days Average Difference	25.52	1.16	20.09	0.93
Lake Catherine Pre-BART	Modeled vs. Measured 20% Worst Days Average Difference	28.60	1.39	21.98	1.07
	Measured vs. Modeled 20% Worst Days Average Difference	41.79	5.89	64.46	7.86
	Modeled & Measured 20% Worst Days Average Difference	27.88	1.34	21.50	1.04
Lake Catherine Post-BART	Modeled vs. Measured 20% Worst Days Average Difference	28.81	1.40	22.01	1.07
	Measured vs. Modeled 20% Worst Days Average Difference	41.25	5.85	66.86	8.24
	Modeled & Measured 20% Worst Days Average Difference	28.42	1.38	21.74	1.05
	Average	**32.95**	**2.92**	**34.72**	**3.16**
	Maximum	**45.64**	**6.47**	**66.86**	**8.24**
	Minimum	**25.52**	**1.16**	**20.09**	**0.93**

The lowest calculated margin of error at Upper Buffalo is 0.93 dv. A larger margin of error, 1.16 dv, was calculated for Caney Creek. As shown in Table 4-2 below, the CALPUFF predicted visibility improvement at Caney Creek and Upper Buffalo obtained from the Arkansas FIP is within the margin of error calculated for each Class I area. Moreover, the predicted visibility improvement is within the lowest margin of error of 0.93 dv regardless of the Class I area. This analysis suggests that the formulation associated with CALPUFF forces the model to predict a value for a given scenario regardless of the accuracy of the value. Moreover, the model predicted number at these lower ranges may not necessarily result in the actual visibility improvement, as the numbers can very well be within the uncertainty in the prediction.

According to the BART guidance, use of 98th percentile or 8th highest value of model prediction is used to reduce the effect of uncertainty in the CALPUFF models. The Lake Catherine analysis uses the worst 20% days or 24 high values to determine the margin of error, thus providing additional data points for the analysis rather than just one data point (i.e., 98th percentile). The use of worst 20% days is consistent with the calculations associated with the reasonable progress goals. Use of the 98th percentile does not address the real issue, that the CALPUFF model is predicting visibility improvements for Lake Catherine that fall within the model's margin of error for this case, thus the projected visibility improvements cannot be *reasonably anticipated* as is required by the Clean Air Act. As stated in the Montana Case, "The issue is not the *perceptibility* of the proposed improvements, but the model's ability to anticipate improvements at a level allegedly within its margin of error, whether perceptible or not to the human eye."[7] EPA has failed to address how CALPUFF can be used as the basis for BART determinations when the predicted visibility improvements in many cases are lower than the calculated margin of error. Due to the uncertainty in the model's ability to predict small visibility improvements, the visibility benefits anticipated from the AR FIP proposed controls on Lake Catherine Unit 4 cannot be *reasonably anticipated*.

Table 4-2. Projected Visibility Improvement from Lake Catherine Margin of Error

Emission Units	Baseline Visibility Impact (dv)	Visibility Improvement from Baseline (Δdv)	Calculated Margin of Error (dv)
Lake Catherine Unit 4			
Caney Creek Wilderness Area	1.371	0.596	1.16
Upper Buffalo Wilderness Area	0.532	0.248	0.93

[1] Data obtained from the proposed AR FIP (FR Vol. 80, No. 67) - https://federalregister.gov/a/2015-06726

[7] Montana Case, at 1147.

4.1.1. Caney Creek Measured Versus Modeled Comparisons

The following plots show comparisons of the CALPUFF predicted impacts from Lake Catherine Unit 4, Pre-BART control, to the IMPROVE measurements from 2002 at Caney Creek.

Figure 4-1. Measured vs. Modeled Total Extinction on 20% Worst Measured Days at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART

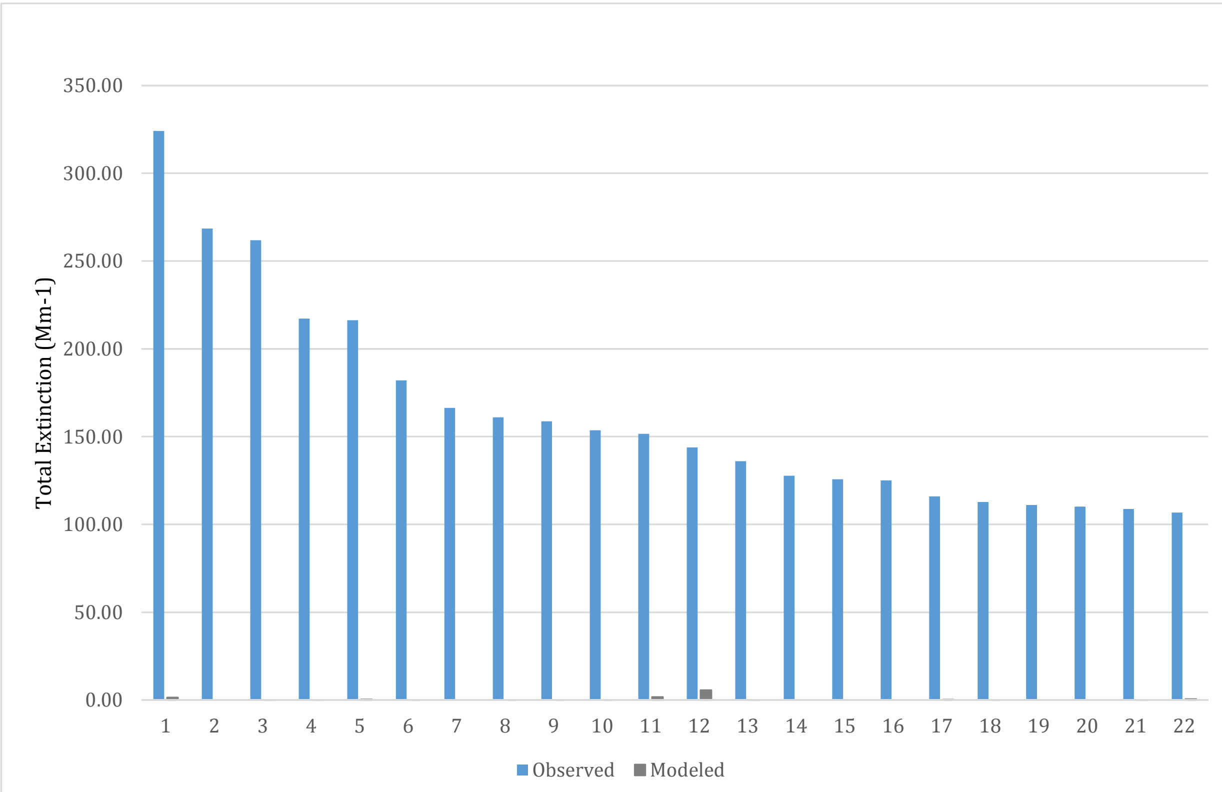


Figure 4-2. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART

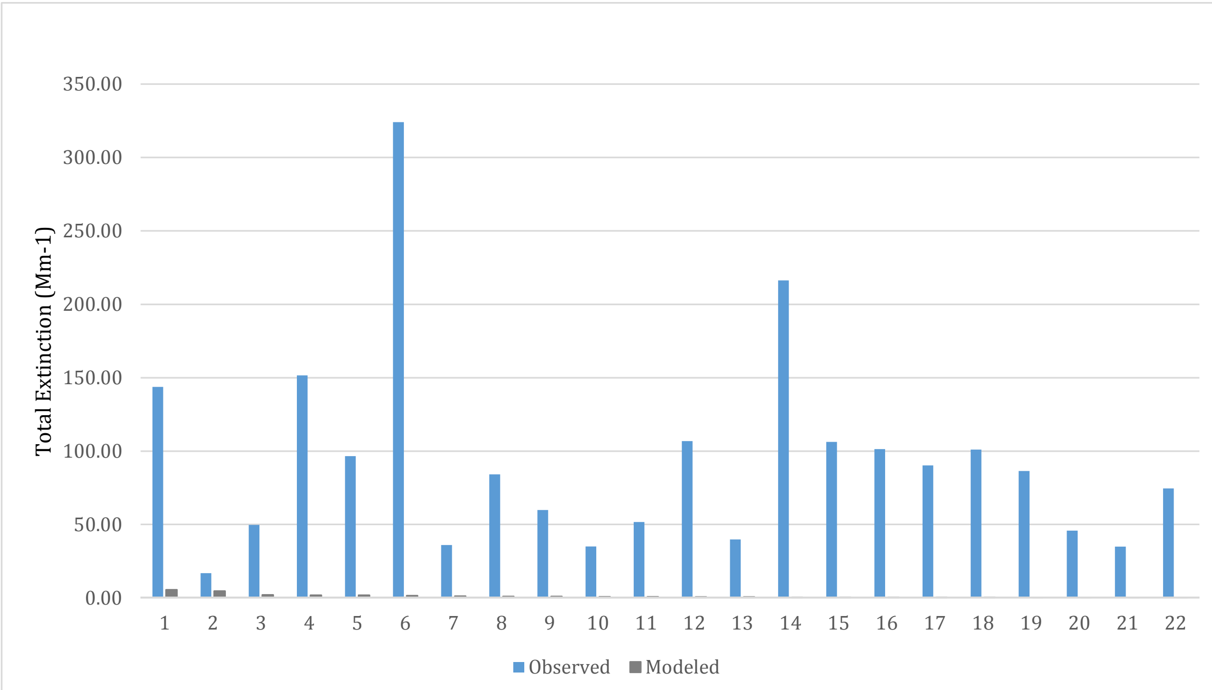
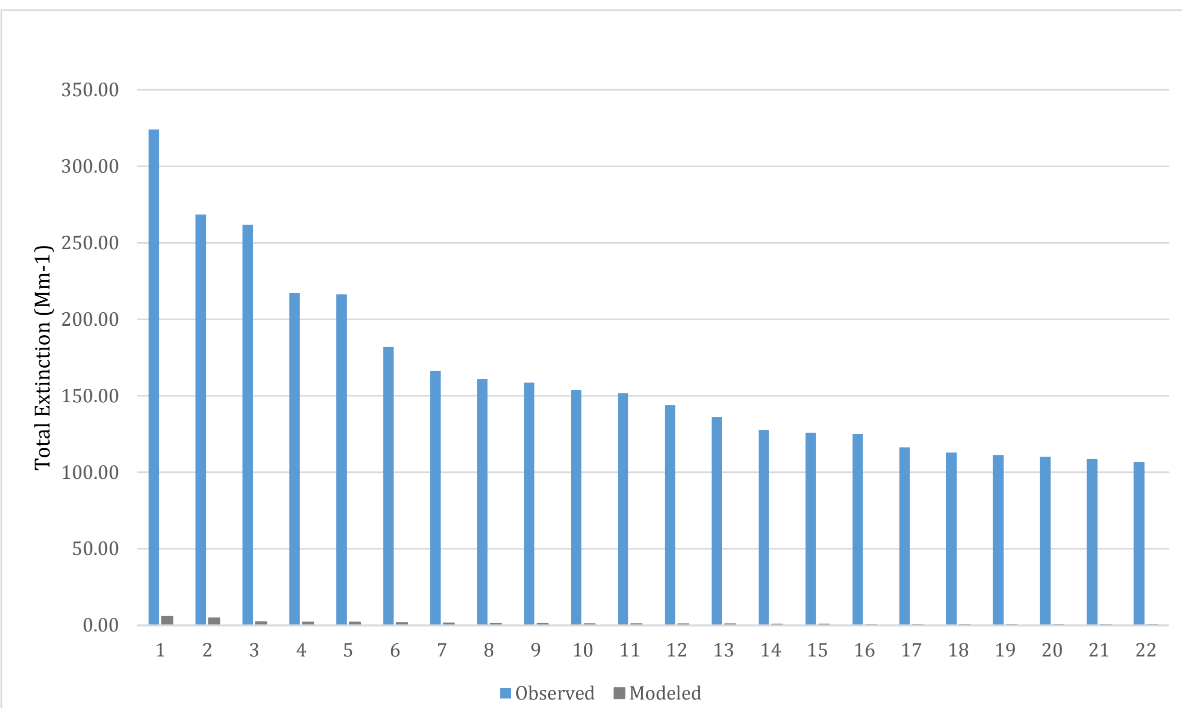


Figure 4-3. Measured and Modeled 20% Worst Days Total Extinction at Caney Creek Wilderness Area in 2002 – Lake Catherine Pre-BART



As demonstrated by the plots above, the Pre-BART impact from Lake Catherine Unit 4 is inconsequential when compared with the IMPROVE measurements, which capture the impact of all sources, including Lake Catherine, on the Class I area. This indicates that the contribution from the Lake Catherine Plant to overall visibility impairment at Caney Creek is negligible.

4.1.2. Upper Buffalo Measured Versus Modeled Comparisons

The following plots show comparisons of the CALPUFF predicted impacts from Lake Catherine Unit 4, Pre-BART control, to the IMPROVE measurements from 2002 for Upper Buffalo.

Figure 4-4. Measured vs. Modeled Total Extinction on 20% Worst Measured Days at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART

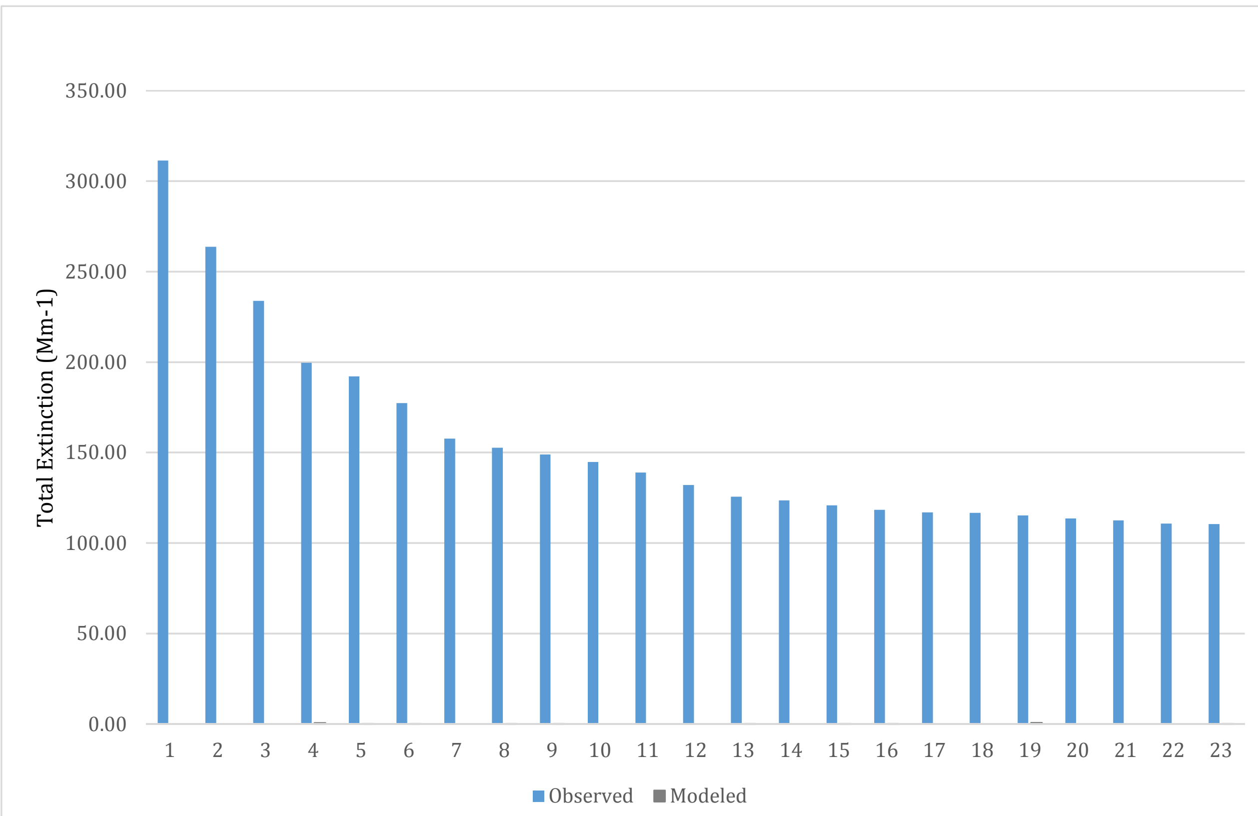


Figure 4-5. Measured vs. Modeled Total Extinction on 20% Worst Modeled Days at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART

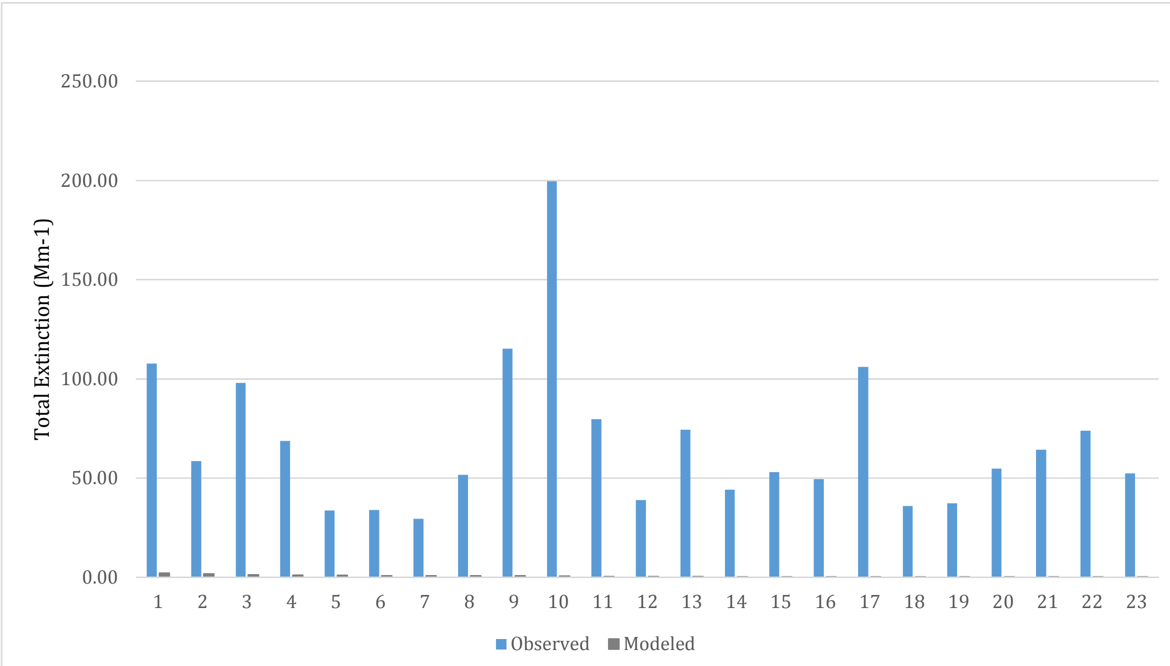
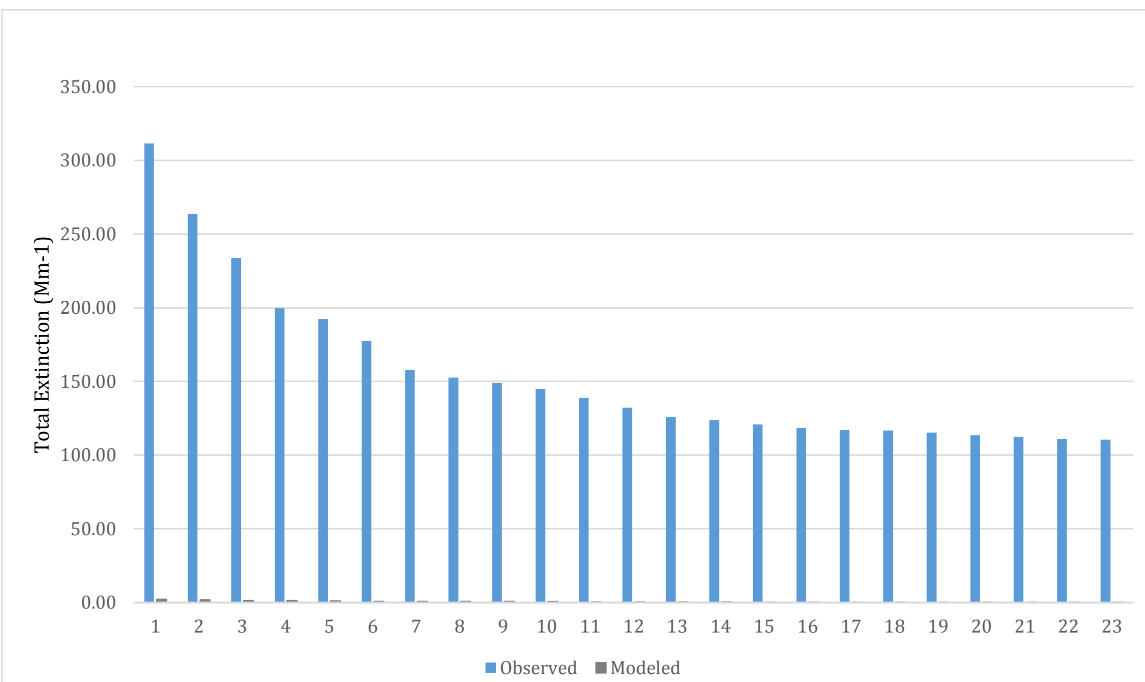


Figure 4-6. Measured and Modeled 20% Worst Days Total Extinction at Upper Buffalo Wilderness Area in 2002 – Lake Catherine Pre-BART



As was the case for Caney Creek, the Pre-BART impact from Lake Catherine Unit 4 is inconsequential when compared with the IMPROVE measurements, which capture the impact of all sources, including Lake Catherine. Thus, the contribution from the Lake Catherine Plant to visibility impairment at Upper Buffalo is negligible.

In June of 2012, TRC wrote a paper entitled *Accuracy of Visibility Protocol Modeling in BART Evaluations*.[8] This paper discussed several case studies comparing modeled values from CALPUFF to measured values from the IMPROVE monitoring network. PPL Montana relied on this study in its successful challenge to the Montana FIP, for its argument that EPA failed to explain why it could reasonably anticipate a visibility improvement when the improvement was within CALPUFF's margin of error.[9,10] An overview of several case studies comparing CALPUFF modeled to measured values, including the study relied upon in the Montana Case, are provided below for reference.

The CALPUFF version approved by EPA for use in BART analyses is Version 5.84, which was released on June 23, 2007.[11] Comparisons of modeled to monitored values demonstrate a significant improvement in model performance.

5.1. MOHAVE GENERATING STATION

CALPUFF modeling completed for the Mohave Generating Station (Mohave Station) showed that the 1,590 megawatt (Mw) coal-fired power plant was causing visibility impacts of 2.31 dv at the Grand Canyon National Park. The plant was permanently shut down in 2005. A review of monitored visibility at IMPROVE stations as close as 90 km to the plant showed no change in either nitrate concentrations or visibility impacts subsequent to the closure of the plant. The measured visibility impairment at the Grand Canyon National Park during the three years prior to (2003-2005) and subsequent to the permanent shutdown (2006-2008) of the Mohave Station were analyzed.[12] Based on a review of data from three (3) IMPROVE monitoring sites, summarized in Table 5-1 below, the changes in visibility were not statistically significant.

Table 5-1. Mohave Visibility Impairment – Before and After

IMPROVE Monitor	2003-2005 (dv)	2006-2008 (dv)	Difference (dv)
Meadview	8.24	8.23	0
Indian Gardens	8.92	8.86	0.1
Hance Camp	6.54	6.61	-0.14

While the actual change at the nearest monitor between pre- and post-shutdown of the Mohave Station, Meadview, was zero dv, the CALPUFF results indicated that visibility impairment caused by the Mohave Station

[8] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[9] Montana Case, at 1146–47.

[10] 42 U.S.C. 7491(g)(2).

[11] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012. Although numerous updates have been released since that time, EPA still relies on an outdated version of the model despite the fact that considerable advancements have been made. Newer versions of CALPUFF include more complex chemistry which allows for more accurate representation of sulfate and nitrate formation by considering ozone chemistry, organic aerosol formation, inorganic gas particle equilibrium, and aqueous phase transformation.

[12] Jonathan Terhorst and Mark Berkman, *Effect of Coal-fired Power Generation on Visibility in a Nearby National Park*, Atmospheric Environment 44, 2010.

was twice the level detectable by the human eye.[13] The maximum CALPUFF predicted visibility impairment was 3.94 dv over 3 years, with a 98th percentile visibility impairment of 2.31 dv from the Mohave Station. Based on the IMPROVE monitoring data, CALPUFF highly overestimated the visibility impairment attributable to the Mohave Station. In reality, the Mohave Station had essentially no impact on the visibility impairment at the Grand Canyon National Park as documented by the change in monitoring values pre- and post-shutdown.

5.2. CRAIG STATION

The Craig Station is located approximately 90 km west of the Mt. Zirkel Wilderness Area (Mt. Zirkel) in northwestern Colorado. A study was completed during the development of the Colorado Regional Haze SIP to compare CALPUFF predicted impacts for the Craig Station to IMPROVE data at Mt. Zirkel.[14] Modeled impacts for the Craig Station on the highest 25 days were compared against IMPROVE data, which includes impacts from all other sources (e.g., other point sources, area sources, mobile sources, etc.). The results showed that the modeled impacts from the Craig Station exceeded the monitored values on 14 out of 19 days, and in some instances by a significant amount. Given that the IMPROVE data reflects the cumulative impact of all sources, both within Colorado and outside of the state, the magnitude of the CALPUFF model over-prediction is severe. Although there is another large power plant located between the Craig Station and Mt. Zirkel, the modeled impacts from the Craig Station alone were larger than the monitored values for all sources combined, which further highlights the degree of over prediction. The modeled values were on average ten times the IMPROVE monitored values (i.e., 9.56 Mm^{-1}).[15]

5.3. NORTH DAKOTA SIP

In the development of the North Dakota Regional Haze SIP, the North Dakota Department of Health (NDDH) relied on photochemical modeling conducted by the Western Regional Air Partnership (WRAP) to determine the impact of sources located outside of the state, as well as non-utility sources in North Dakota.[16] CALPUFF was utilized to determine the impacts of utility sources within the state; however, NDDH utilized alternate options in the CALPUFF model to address known areas of inaccuracy. The specific areas where they deviated from the EPA BART prescribed approach include:

- Consideration of boundary conditions based on CMAQ modeling, rather than ignoring the impact of sources outside of the domain as is done in the EPA approach;
- Puff splitting;
- Diffusion coefficients based on actual measurements of turbulence rather than the 1952 Pasquill-Gifford diffusion confidents required by the EPA approach;
- Meteorological data from the National Center for Environmental Predictions (NCEP) Rapid Update Cycle (RUC) forecast model; and
- Use of hourly average ammonia concentrations instead of an annual average value.

The resulting CALPUFF values were then compared to IMPROVE monitoring data from the South Unit at Theodore Roosevelt National Park, as summarized in Table 5-2 below.[17]

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[13] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[14] Gale Hoffnagle, Evaluation of Craig BART Modeling for Regional Haze Analysis, testimony before the Colorado Air Quality Commission, November 18, 2010.

[15] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[16] North Dakota State Implementation Plan, February 24, 2010.

[17] North Dakota State Implementation Plan, Chapter 8, February 24, 2010.

A review of extinction values showed that the average difference between measured and modeled extinction was 0.37 Mm^{-1} with a standard deviation of 12.6 Mm^{-1}.[18] EPA rejected NDDH's modeling on the basis that it included impacts from other sources rather than evaluating the impairment due to BART sources against the natural background visibility impairment ("dirty" background analysis vs. "clean" background analysis). EPA did not specifically comment on the accuracy of NDDH's CALPUFF modeling. Even with the revisions to the modeling methodology applied by NDDH, the margin of error was still 0.39 dv on average.[19]

Table 5-2. NDDH Measured versus Modeled Nitrate Concentrations

Theodore Roosevelt South Unit	Observed ($\mu g/m^3$)	Predicted ($\mu g/m^3$)
98th Percentile	2.03	2.06
90th Percentile	1.21	1.21
Average of 20% Worst Days	1.42	1.41
Annual Average	0.53	0.53

5.4. COLSTRIP GENERATING STATION

As briefly described above, TRC conducted an analysis of measured versus modeled visibility impacts for the Colstrip Station located in eastern Montana, which is partially owned and operated by PPL Montana, LLC. TRC specifically completed comparisons for the worst 20% measured days and worst 20% modeled days (where a corresponding measurement was available). The study found that CALPUFF significantly over predicted impacts from the Colstrip Station, as impacts from this source alone were frequently higher than the monitored values, which include all sources (e.g., point, area, mobile) as well as the Colstrip Station. Modeled nitrate extinction from the Colstrip Station alone was higher than the monitored values on 11 out of 22 of the worst 20% modeled days at the Theodore Roosevelt IMPROVE monitoring site. At the UL Bend Wilderness Area IMPROVE monitor, modeled nitrate extinction from the Colstrip Station exceeded the monitored values on 11 out of 28 of the worst 20% modeled days. At the North Absaroka IMPROVE site, the impact from the Colstrip Station was over predicted on 9 out of 20 days of the worst 20% modeled days. At the Yellowstone IMPROVE site there are 10 days when the modeled extinction from the Colstrip Station exceeded the monitored values for the worst 20% modeled days.

Based on this analysis, PPL Montana, LLC, the operator and partial owner, challenged EPA's BART analysis for Colstrip Station arguing that EPA could not "reasonably anticipat[e] as required by the [Clean Air Act]" the maximum predicted visibility improvement for Colstrip Units 1 and 2 because the incremental visibility improvement was within the model's margin of error.[20] The U.S. Court of Appeals for the Ninth Circuit concluded that EPA's response that low levels of visibility impairment must be addressed regardless of whether the visibility improvements are perceptible to the human did not resolve how EPA can reasonably anticipate visibility improvements within a model's margin of error.[21] Given the small magnitude of the CALPUFF predicted visibility improvements for Entergy's Lake Catherine Unit 4, Entergy similarly questioned whether EPA can

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[18] These statistics are based on the exclusion of January 26, 2002 which was an outlier.

[19] [19] Gale F. Hoffnagle, Accuracy of Visibility Protocol Modeling in BART Evaluations, TRC Environmental Corporation, June 15, 2012.

[20] Montana Case, at 1146.

[21] *Id*.

reasonably anticipate visibility improvement from additional controls on the Lake Catherine Plant. As such, Trinity utilized a similar methodology to determine the CALPUFF margin of error specifically for the Lake Catherine analysis. Trinity's analysis is summarized in detail within Sections 4 *Modeling Methodology* and 5 *Results* of this report. As documented in the results section, the visibility benefits anticipated from the AR FIP proposed controls on Lake Catherine Unit 4 cannot be *reasonably anticipated* because the visibility improvements are within CALPUFF's margin of error.

6. CONCLUSIONS

Based on the analysis completed for the Entergy Lake Catherine Plant, the minimum calculated margin of error for CALPUFF for the Lake Catherine Plant is 0.93 dv. The CALPUFF predicted visibility improvements associated with EPA's proposed BART for Lake Catherine Unit 4 at Caney Creek and Upper Buffalo fall within this margin of error. As such, the visibility improvements at each of these Class I areas associated with the proposed BART cannot be *reasonably anticipated*, as is required by the Clean Air Act.[22]

[22] 42 U.S.C. 7491(g)(2).

Entergy Arkansas Inc.

Comments on the Proposed Approval and Promulgation of Implementation Plans; Arkansas; Interstate Transport State Implementation Plan to Address Pollution Affecting Visibility

Docket No. EPA-R06-OAR-2008-0633

Submitted on:
August 5, 2015

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

Via:
http://www.regulations.gov

ENTERGY ARKANSAS INC.

COMMENTS ON THE PROPOSED APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS; ARKANSAS; INTERSTATE TRANSPORT STATE IMPLEMENTATION PLAN TO ADDRESS POLLUTION AFFECTING VISIBILITY

EPA-R06-OAR-2008-0633

I. INTRODUCTION

On July 6, 2015, the U.S. Environmental Protection Agency ("EPA" or "Agency") published in the *Federal Register*, at 80 Fed. Reg. 38419, a proposed rule that would disapprove a revision to the State Implementation Plan ("SIP") submitted by the State of Arkansas on September 16, 2009, for the purpose of addressing the requirements of the Clean Air Act ("CAA") regarding interference with other states' programs for visibility protection for the 2006 revised 24-hour fine particulate matter ("$PM_{2.5}$") National Ambient Air Quality Standard ("NAAQS") ("Proposed Rule" or "Proposal"). Section 110(a)(2)(D)(i)(II) of the CAA, which EPA identifies as "Prong 4," requires that SIPs contain provisions to prohibit emissions from within the state from interfering with measures required to be included in the implementation plan for any other state under the visibility protection provisions of Part C of the CAA. EPA has interpreted this "good neighbor" provision as requiring states to include in their SIPs measures to prohibit emissions that would interfere with the reasonable progress goals set to protect Class I areas in other states. 80 Fed. Reg. at 38420. In addition to proposing to disapprove Arkansas' Prong 4 SIP submittal, EPA is proposing that the regional haze Federal Implementation Plan ("FIP") that the Agency proposed on April 8, 2015, *see* 80 Fed. Reg. 18944, remedies the deficiency created by the proposed disapproval of Arkansas' submittal.

Entergy Arkansas Inc. ("EAI" or "Entergy") owns and operates three facilities that EPA would regulate under the regional haze FIP: White Bluff Electric Power Plant ("White Bluff"); Independence Steam Electric Station ("Independence"); and Lake Catherine Plant ("Lake Catherine"). As proposed, the regional haze FIP would impose Best Available Retrofit Technology ("BART") emission limits on White Bluff Units 1 and 2, the Auxiliary Boiler at White Bluff, and Unit 4 at Lake Catherine, as well as reasonable progress emission limits on Units 1 and 2 at Independence. As a result, EPA's proposal that the proposed regional haze FIP would satisfy Arkansas' Prong 4 obligation directly and significantly impacts Entergy.

In these comments, Entergy discusses its legal concerns with the Proposed Rule. Entergy appreciates EPA's consideration of these comments.

II. COMMENTS

A. Arkansas' SIP Satisfied Prong 4, Rendering Reliance on EPA's Proposed Regional Haze FIP Unnecessary.

EPA argues that Arkansas' SIP submittal fails to satisfy Prong 4 for two reasons. First, although Arkansas indicated in its SIP submittal that it complies with the Prong 4 requirement, it did not explain how it meets the requirement. 80 Fed. Reg. at 38421. Second, in 2012, EPA partially disapproved the SIP revision submitted by Arkansas in 2008 to address the regional haze requirements, including disapproving a large portion of Arkansas' BART determinations. *See* 77 Fed. Reg. 14604 (Mar. 12, 2012). As a result, EPA contends, the corresponding emission reductions from Arkansas sources upon which other states had relied in their regional haze SIPs would not take place. *Id.* EPA therefore proposes that its proposed regional haze FIP is necessary to address the requirement regarding interference with other states' programs for visibility protection for the 2006 $PM_{2.5}$ NAAQS. *Id.* at 38422.

Contrary to EPA's position, the Arkansas SIP submittal satisfies Prong 4, rendering the regional haze FIP unnecessary to address interference with other states' visibility SIPs. First, the SIP submittal does explain how it complies with Prong 4 by specifically identifying the state regulations that ensure emissions from Arkansas sources will not interfere with other states' regional haze SIPs. Second, while EPA has issued guidance documents stating that Prong 4 may be satisfied through the promulgation of a regional haze SIP, this is not the *only* way in which a state may meet its obligation. *See* Guidance for State Implementation Plan Submissions to Meet Current Outstanding Obligations Under Section 110(a)(2)(D)(i) for the 8-hour Ozone and $PM_{2.5}$ National Ambient Air Quality Standards, at 9-10 (Aug. 15, 2006).[1] Indeed, EPA itself has acknowledged states may satisfy Prong 4 by something other than an EPA-approved regional haze SIP. 76 Fed. Reg. 8326, 8328 (Feb. 14, 2011) (Proposed Approval and Promulgation of State Implementation Plans; State of Colorado; Interstate Transport of Pollution Revisions for the 1997 8-Hour Ozone and 1997 $PM_{2.5}$ NAAQS: "Interference With Visibility" Requirement).

In its SIP submittal, Arkansas indicated that Prong 4 was satisfied by (1) the EPA-approved Arkansas Pollution Control and Ecology Commission's Regulation 19, Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Chapter 14; (2) A.C.A. § 8-4-311(a)(2), which authorizes ADEQ to advise, consult, and cooperate with other agencies of the state, political subdivisions, industries, other states, the federal government, and with affected groups to control or abate air pollution and to prevent new air pollution; and (3) A.C.A. § 8-4-311(a)(8), which authorizes ADEQ to represent the state in all matters pertaining to the plans,

[1] Guidance issued after submittal of the Arkansas' SIP revision on September 16, 2009, similarly indicates that a regional haze SIP is not the exclusive way in which a state may demonstrate compliance with Prong 4. *See* Guidance on SIP Elements Required Under Sections 110(a)(1) and (2) for the 2006 24-Hour Fine Particle National Ambient Air Quality Standards, at 5-6 (Sep. 25, 2009); Guidance on Infrastructure State Implementation Plan Elements Under Clean Air Act Sections 110(a)(1) and 110(a)(2), at 34 (Sep. 13, 2013) ("A state air agency may elect to satisfy prong 4 by providing, as an alternative to relying on its regional haze SIP alone, a demonstration in its infrastructure SIP submission that emissions within its jurisdiction do not interfere with other air agencies' plans to protect visibility.") ("2013 Guidance").

procedures, or negotiations for interstate compacts in relation to air pollution control. Prong 4 SIP Submittal Attachment at 2.[2] This was sufficient to comply with Prong 4, because it identifies the regulatory mechanisms through which Arkansas works with other states to ensure that its emissions do not interfere with visibility efforts. Arkansas emissions cause and contribute to visibility impairment primarily in two Class I areas in Missouri, Hercules Glades Wilderness Area and Mingo National Wildlife Refuge, and potentially other Class I areas in Oklahoma, Kentucky, Illinois and Louisiana. Proposed Approval Regional Haze Interstate Transport SIP, 76 Fed. Reg. 64,186, 64,193, 64,215 (Oct. 17, 2011); Final Approval Regional Haze Interstate Transport SIP, 77 Fed. Reg. 14604, 14623 (Mar. 12, 2012). Of these states, only Missouri relied upon anticipated BART controls from sources in Arkansas when developing its regional haze SIP. *See* Missouri Regional Haze SIP, at 45 (June 25, 2009).[3] Subsequent to EPA's partial disapproval of the Arkansas BART limits, Missouri released a 5-Year Progress Report demonstrating that Mingo and Hercules Glades are on track to meet the 2018 visibility goals. Missouri Regional Haze Plan: 5-Year Progress Report, at 4, 17 (Aug. 29, 2014).[4] Missouri concluded that this progress was the result of emissions reductions at Missouri sources and that further reductions are not necessary. *Id.* at 1, 4, 17. Thus, Missouri has determined that no additional measures are needed in Arkansas to prevent Arkansas sources from interfering with Missouri's reasonable progress efforts.

B. EPA's Proposal to Rely on its Proposed FIP Is Premature and Violates the Notice and Comment Requirement.

EPA proposes to find that the requirements of Prong 4 will be satisfied by the combination of the emission control measures in the proposed regional haze FIP, and the already approved portions of the Arkansas regional haze SIP. 80 Fed. Reg. at 38422. It is inappropriate for EPA to propose such a finding when the Agency has not yet finalized its regional haze FIP. As EPA recognizes, the Agency cannot finalize this proposal unless and until it finalizes its action on the regional haze FIP. *See id*. Depending upon the comments submitted to EPA on the proposed FIP, the final regional haze FIP could be substantially different from the proposal. For example, Entergy intends to submit comments on the proposed regional haze FIP objecting to the proposed BART limits for White Bluff and the proposed reasonable progress limits for Independence. Entergy also has identified numerous legal and technical deficiencies in the proposed FIP, which will be discussed in detail in Entergy's comments on the proposed FIP.

It is impossible to know, during the comment period on this rulemaking, whether the final FIP will rectify these problems. Because significant changes could be made to the final FIP, because these changes are unforeseeable, and because Entergy has significant concerns that the final FIP may be legally and technically deficient, it is unreasonable to request public comment on a proposal that the final FIP will satisfy Prong 4. This is a clear violation of EPA's obligation under the Administrative Procedure Act to provide adequate notice and opportunity to comment on a proposed rule. 5 U.S.C. § 553. EPA should defer requesting public comment on this issue until after the Arkansas regional haze FIP has been finalized.

[2] Docket ID EPA-R06-OAR-2008-0633-0006.
[3] http://dnr.mo.gov/env/apcp/reghaze/moreghaze-09rev.pdf.
[4] http://dnr.mo.gov/env/apcp/reghaze/complete-RegionalHaze-5-yr-Rpt-submittal.pdf.

III. CONCLUSION

Entergy appreciates the opportunity to comment on the Proposed Rule. For the reasons explained in these comments, Entergy strongly urges EPA to approve the Arkansas Prong 4 SIP submittal. In the alternative, Entergy requests that EPA defer issuing a final rule until after (1) the final regional haze FIP for Arkansas has been issued, and (2) EPA has reopened the comment period for this Proposal to allow interested parties to comment on EPA's proposal that the final Arkansas regional haze FIP satisfies Arkansas' Prong 4 requirements.

Respectfully submitted,

Kelly M. McQueen
Assistant General Counsel – Environmental (Lead)
Entergy Services, Inc.

These are late comments that were submitted to us outside of the comment period for our proposed rulemaking. These comments are not considered as part of the Administrative Record for our Arkansas Regional Haze and Interstate Visibility Transport FIP rulemaking EPA-R06-OAR-2015-0189.

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August 8, 2016

Mr. Guy Donaldson
Chief, Air Planning Section (6PD-L)
U.S. Environmental Protection Agency
Region 6
1445 Ross Avenue, Suite 700
Dallas, TX 75202-2733

Re: Request for EPA to Consider and Amend Administrative Record Regarding Material New Information for the Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas, Docket No. EPA-R06-OAR-2015-0189

Dear Mr. Donaldson:

Entergy Arkansas Inc. ("EAI") respectfully requests that the U.S. Environmental Protection Agency ("EPA") incorporate into the above docket the attached Supplemental Comments and supporting information regarding EPA's analysis of the best available retrofit technology ("BART") requirements in the final Regional Haze and Interstate Visibility Transport Federal Implementation Plan ("FIP") for Arkansas ("Supplemental Comments"). Although the comment period on the proposed rule has closed, EPA has the authority and discretion to consider the attached Supplemental Comments and supporting information. The material submitted corrects one of the fundamental bases of EAI's October 2013 *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* ("October 2013 Five Factor Analysis"). This information is thus crucial to ensuring that EPA has the most accurate, complete, and timely information, and EAI respectfully requests that EPA consider this information and include it as part of the record.

The Supplemental Comments provide critically important information that (1) became available after the comment period closed, and (2) goes to core issues in the rulemaking.

Specifically, the comments provide information on current operations and emissions at the White Bluff Steam Electric Station ("White Bluff"), as well as future projected operations at White Bluff, which necessitate corrections to EAI's October 2013 Five Factor Analysis. Since the date of EAI's Comments on the proposed FIP, dated August 7, 2015 ("EAI Comments"), due largely to market conditions, including lower natural gas prices and dispatch of the White Bluff units through the Midcontinent Independent System Operator ("MISO"), and EAI's ongoing long range resource planning, EAI's assumed remaining useful life ("RUL") of the two coal-fired units at White Bluff has changed.[1]

The Supplemental Comments demonstrate that, based on the adjustment to the RULs, in addition to other changes described in the Supplemental Comments and Exhibit 1 (*Update to the Revised BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2*), the sulfur dioxide ("SO_2") control technology proposed as BART for White Bluff is economically infeasible/unjustifiable. EAI now projects the RULs to be four and five years from the proposed date of compliance with the FIP, with one unit ceasing coal fired operation at the end of 2025 and the other unit at the end of 2026.

Additionally, Exhibit 2 of the Supplemental Comments includes an evaluation of the most recent monitoring ("IMPROVE") data for the two Arkansas Class I areas, Caney Creek Wilderness Area ("Caney Creek") and Upper Buffalo Wilderness Area ("Upper Buffalo). This evaluation shows that visibility impairment continues to decline and trend downward at a steeper slope than the uniform rate of progress ("URP") glidepaths for both Class I areas in Arkansas. Additionally, the updated IMPROVE data further confirm that both Caney Creek and Upper Buffalo already have surpassed the reasonable progress goals ("RPGs") that EPA has proposed for these Class I areas. Accordingly, reasonable progress controls during the first planning period are not necessary to achieve the proposed RPGs.

All of the information presented in EAI's Supplemental Comments is relevant and material to EPA's decision making, and must be considered by EPA and be part of the record to ensure full and reasoned decision making based on all pertinent and current facts. Thank you for considering these Supplemental Comments, and we will be happy to answer any follow up questions.

Sincerely,

Kelly M. McQueen
Assistant General Counsel – Environmental (Lead)
Entergy Services, Inc.

[1] The RULs discussed in this letter and the Supplemental Comments are based on an assumption that the FIP will be finalized this year and require SO_2 controls to be installed within five years. *See* EAI Comments at 6.

Attachments:

Supplemental Comments of Entergy Arkansas, Inc., including:

- Exhibit 1 – *Update to the Revised BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2*, Trinity Consultants (Aug. 8, 2016)

- Exhibit 2 – *Assessment of Recent Class I Area IMPROVE Monitoring Data*, Trinity Consultants, (Aug. 8, 2016)

cc: Becky Keogh, Director, Arkansas Department of Environmental Quality

Entergy Arkansas Inc.

Supplemental Comments

On the Proposed Regional Haze and Interstate Visibility Transport

Federal Implementation Plan for Arkansas

Docket No. EPA-R06-OAR-2015-0189

Submitted on:
August 8, 2016

To:
U.S. Environmental Protection Agency
1445 Ross Avenue, Suite 700
Dallas, Texas 75202-2733

I. INTRODUCTION

During the comment period on the proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas ("Proposed FIP"),[2] Entergy Arkansas Inc. ("EAI") submitted comments addressing the proposed sulfur dioxide ("SO_2") and nitrogen oxide ("NOx") best available retrofit technology ("BART") requirements for the two coal-fired units at the White Bluff Steam Electric Station ("White Bluff").[3] Specifically, for SO_2 BART, EAI submitted comments proposing to end coal-fired usage at the two White Bluff units by the end of 2027 for one unit and by the end of 2028 for the other unit, which limited their remaining useful lives for the purposes of calculating the cost effectiveness of the proposed SO_2 BART control technology. For NOx BART, EAI proposed a compound pound per hour/pound per million btu limitation for the White Bluff units in the event that EPA did not finalize a determination that meeting the Cross State Air Pollution Rule ("CSAPR") in Arkansas was more effective than source-specific NOx BART. EAI proposed a pound per hour limitation due to concerns that the White Bluff units would not be able to meet EPA's proposed NOx BART limit of 0.15 lb NOx/mmBtu at loads of less than 50 percent of capacity. Finally, EAI submitted IMPROVE data demonstrating that visibility is improving at a greater rate than the glidepaths for the two Arkansas Class I areas and that, as a result, reasonable progress controls on Arkansas sources are unnecessary during the first regional haze planning period.

Since the close of the comment period, new information has become available that revises EAI's assumptions for the proposed SO_2 and NOx BART requirements for the White Bluff units. Due to recent market conditions, which EAI expects will continue for the foreseeable future, the White Bluff coal-fired units have been dispatched less and are operating at lower annual average capacity factors. As a result and consistent with EAI's long-range plans, EAI now anticipates that it will cease combusting coal at the White Bluff units by the end of 2026[4], which further limits their remaining useful lives than EAI proposed in its Comments and definitively demonstrates that the cost of SO_2 control technology at White Bluff is not cost effective. Accordingly, EAI requests EPA to determine SO_2 BART for each of the White Bluff coal-fired units to be either a 30-boiler operating day emission rate of 0.06 lb SO_2/mmBtu based on the installation of the previously proposed SO_2 controls or the cessation of operation of the coal-fired units by the end of 2026 as an alternative to the installation of the costly controls, as described more fully below. In addition, EAI has refined its proposed NOx BART emission rate limitation to ensure that the White Bluff units will be able to meet the limitations at lower capacity factors. Finally, more recent Interagency Monitoring of Protected Visual Environments ("IMPROVE") data further support EAI's Comments that reasonable progress controls are unnecessary for visibility improvement at Arkansas' two Class I areas during the first planning

[2] 80 Fed. Reg. 18,944 (Apr. 8, 2015).

[3] *See* Entergy Arkansas Inc. Comments on the Proposed Regional Haze and Interstate Visibility Transport Federal Implementation Plan for Arkansas (Aug. 7, 2015); Docket No. EPA-R06-OAR-2015-0189-0166 ("EAI Comments"). These Supplemental Comments do not waive any argument or issue raised in EAI's Comments.

[4] As outlined in EAI's recent Integrated Resource Plan and consistent with its long-term strategy to diversify its fuel portfolio, this timeline – as opposed to EPA's proposed FIP requirements - would better allow EAI time to replace the units' capacity and develop other supply options including renewables and energy efficiency while continuing to provide reliable service at the lowest cost possible.

period. The recent IMPROVE data show that visibility in both Class I areas in Arkansas, Caney Creek Wilderness Area ("Caney Creek") and Upper Buffalo Wilderness Area ("Upper Buffalo), is already better than both the uniform rate of progress ("URP") goals for the first planning period and the reasonable progress goals ("RPGs") that EPA proposed for the two Class I areas.

EAI's Supplemental Comments and recommended SO_2 and NOx BART determinations address issues on which EPA requested comment during the comment period and support the comments that EAI previously submitted to EPA.[5] Accordingly, it is appropriate that EPA consider these Supplemental Comments before finalizing the Arkansas Regional Haze FIP.

II. COMMENTS

A. Corrections to the October 2013 White Bluff Five Factor Analysis

At the time EAI submitted its Comments on the Proposed FIP, EAI proposed that it would cease burning coal at the two coal-fired units at White Bluff in 2027 and 2028.[6] This changed the calculation of the costs of installing and operating SO_2 control technology on the units due to their limited remaining useful life ("RUL") of six to seven years and demonstrated that EPA's proposed SO2 BART was not feasible.[7] Since that time, there have been notable changes in the market conditions affecting dispatch of the White Bluff units. Specifically, natural gas prices have dropped sharply and are anticipated to continue to remain low.[8] The decline in natural gas prices, coupled with the White Bluff units' dispatch through the Midcontinent Independent System Operator ("MISO"), have significantly decreased the units' annual average capacity factors as compared to their prior historical annual average capacity factors. Figures 1 & 2 below illustrate this change in operation of the units.

[5] *See* EAI Comments at Sections III. A, C and E.

[6] *Id*. at 5.

[7] The RULs are based on an assumption that the FIP will be finalized this year and require controls to be installed within five years. *See id*. at 6.

[8] *See Annual Energy Outlook 2016 Early Release: Annotated Summary of Two Cases*, U.S. Energy Information Administration, at 50 (May 17, 2016), available at https://www.eia.gov/forecasts/aeo/er/pdf/0383er(2016).pdf.

Figure 1. White Bluff Unit 1 Heat Input (MMBtu/yr, 12-month Rolling Values)

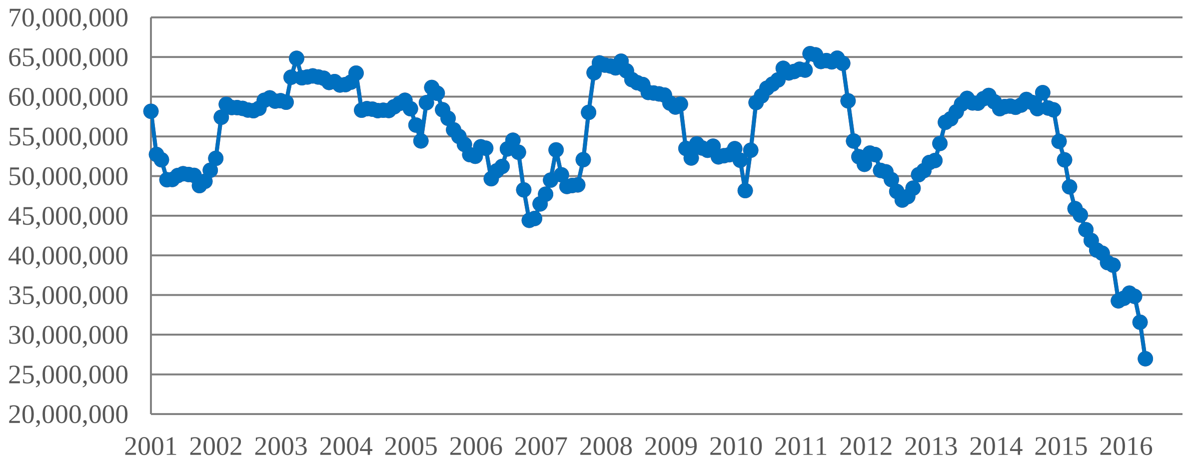
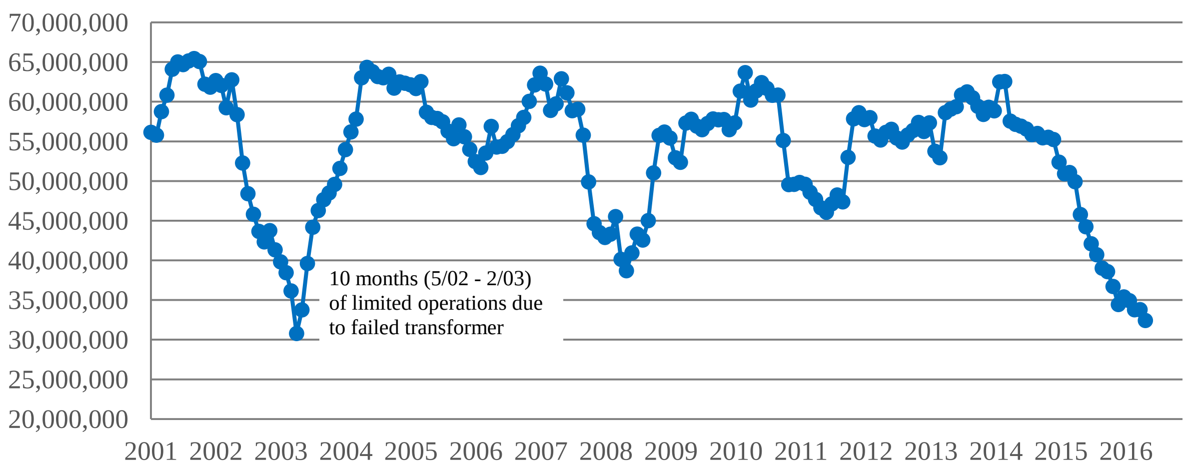


Figure 2. White Bluff Unit 2 Heat Input (MMBtu/yr, 12-month Rolling Values)



Due to the changes in market conditions at White Bluff resulting from the lower natural gas prices and lower dispatch of the White Bluff coal-fired units through MISO and consistent with EAI's ongoing resource planning, EAI has revised its analysis of the continued operation of the White Bluff units and projects that the units will cease combusting coal by the end of 2025 and the end of 2026.[9] This necessitates a change to the amortization period for SO_2 controls, since the units are not anticipated to continue operating beyond 2026. EAI further projects that one of the White Bluff units will operate at a capacity factor of 50 percent or less during 2025.

The limited RULs for the two White Bluff units, coupled with the 50 percent capacity factor operating constraint on one unit in 2025 (hereafter both are referred to as "operation restrictions"), necessitate corrections to EAI's October 2013 *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* ("October 2013 Five Factor Analysis"). Specifically, as

[9] At this time, EAI is unable to make a final determination as to which unit will cease operation first.

discussed further in the attached report prepared by Trinity Consultants, *Update to the BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2* (Aug. 8, 2016) (Exhibit 1 to these Supplemental Comments), when the operation restrictions are taken into account for the two White Bluff units, the costs of installing the proposed SO_2 BART control technology, spray dryer absorber ("SDA") technology, is unjustifiable at White Bluff. Based on the detailed cost analysis prepared in 2015 by Sargent & Lundy,[10] the cost effectiveness of SDA would range from approximately $10,400 to $11,800 per ton.[11] Even using EPA's cost projections, which EAI believes ignores significant cost elements of such a project,[12] the costs are in excess of $5,000 per ton.[13] These are unacceptably high cost effectiveness values and cannot be considered BART for the White Bluff units.

Given their short RULs of four or five years, as demonstrated in Exhibit 1, the proposed SO_2 BART controls for the White Bluff units are not cost effective. As a result, SO_2 BART for the units should be *no additional controls*.[14] EAI requests that the final Arkansas regional haze FIP explicitly provide EAI with the option for SO_2 BART of either an emission limitation of 0.06 lb SO_2/mmBtu on a 30-boiler operating day average, or a binding requirement that (1) one unit will cease coal fired operation by the end of 2025 and the other unit by the end of 2026, and (2) one unit will be limited to a capacity factor of no greater than 50 percent in 2025.

B. NOx BART Limit for White Bluff

If EPA does not provide that compliance with CSAPR satisfies the NOx BART requirements for Arkansas' electric generating units,[15] EAI's Comments proposed that the White Bluff units meet a rolling 30-boiler operating day average NOx limit of 1,342.5 lb NOx/hr, based on the installation of low NOx burners and separated overfire air for all periods of operation and, additionally, a rolling 30-boiler operating day average NOx emission rate of 0.15 lb NOx/mmBtu for unit operation at 50-100 percent of capacity.[16] EAI proposed the pound per hour limit due to concerns that the vendor Entergy selected to supply the NOx control technology would only guarantee EPA's proposed NOx BART rate of 0.15 lb NOx/mmBtu for loads of 50 percent of capacity or greater.[17] Given the updated capacity factor information for the White Bluff units as discussed above in Section II.A, EAI has even greater concerns that the units will be unable to meet EPA's proposed 30-boiler operating day average NOx BART limit of 0.15 lb NOx/mmBtu for significant periods of time.

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[10] Exhibit B to EAI Comments.

[11] Exhibit 1 at 1-2.

[12] *See* EAI Comments at 8-11.

[13] Exhibit 1 at 3.

[14] EAI continues to propose that, as an interim SO_2 reduction measure, the White Bluff units would take a limit on their permitted SO_2 emission rates of 0.6 lb SO_2/mmBtu on a rolling 30-day average basis beginning three years from the effective date of the final FIP through ceasing operation. This is a 50 percent reduction from their current permitted limits. EAI Comments at 13.

[15] *Id.*

[16] *Id*. at 13-14; 51-52.

[17] *Id*. at 13, n. 16; 51.

EAI continues to request that, if EPA rejects a determination that CSAPR equals BART for Arkansas, EPA should adopt a pound per hour limitation for the White Bluff units when they are operating at a low capacity factor. EAI has refined its analysis of the proposed NOx limitation, however, and now proposes the following limits as NOx BART for each of the White Bluff units:

i. For unit operation at 0-49.9 percent of capacity, a limit of 1,305 lb NOx/hr, based on a 30-boiler operating day rolling average and

ii. For unit operation at 50-100 percent of capacity, a limit of 0.15 lb NOx/mmBtu based on a 30-boiler operating day rolling average to include only those hours for which the unit was dispatched at 50 percent or greater of maximum capacity.

EAI believes the revised rate of 1,305 lb NOx/hr is achievable and appropriate as NOx BART for the White Bluff units for periods when the White Bluff units are operating at a low capacity factor.

C. Most Recent IMPROVE Data

In the EAI Comments, EAI presented IMPROVE monitoring data showing that the haze index has been consistently below the uniform rate of progress ("URP") in both Caney Creek and Upper Buffalo.[18] As a result, reasonable progress controls for the first planning period are unnecessary.[19] This conclusion is bolstered by more recent IMPROVE monitoring data that has become available subsequent to the close of the comment period. As discussed further in Trinity's Report, *Assessment of Recent Class I Area IMPROVE Monitoring Data*, Trinity Consultants, (Aug. 8, 2016) (Exhibit 2 to these Supplemental Comments), the IMPROVE data for January 2014 through September 2015 show that visibility continues to improve by a greater amount than the URPs in Caney Creek and Upper Buffalo.[20]

In addition, the recent IMPROVE data further confirm that visibility in the two Arkansas Class I areas is already better than the RPGs that EPA proposed for the areas. EPA proposed to set the RPG for the 20 percent worst days at 22.27 deciviews ("dv") for Caney Creek and at 22.33 dv for Upper Buffalo.[21] The recent IMPROVE data for both Class I areas demonstrate that the areas already are exceeding the proposed RPGs, as well as Arkansas' RPGs and that visibility impairment is continuing to trend downward.[22]

Given that Caney Creek and Upper Buffalo already have surpassed the URP goals, Arkansas' RPGs, and EPA's proposed RPGs for the first planning period, reasonable progress

[18] *Id*. at 20-23.

[19] *See generally*, *id*. at 17-43 (discussion of why reasonable progress controls are unnecessary at the Independence Steam Electric Station during the first planning period).

[20] Exhibit 2 at 1-3.

[21] 80 Fed. Reg. at 18,997.

[22] Exhibit 2 at 3.

controls during the first planning period are *not necessary* to ensure reasonable progress towards the natural visibility goal. *See* 42 U.S.C. § 7491(b)(2) (requiring regional haze implementation plans to contain measures "necessary to make reasonable progress toward meeting the national goal").

III. CONCLUSION

The operation restrictions for the White Bluff coal-fired units and attendant cost information provided in these Supplemental Comments and in Exhibit 1 demonstrate that the BART determination for SO_2 for the White Bluff coal-fired units should be no additional controls. For SO_2 BART, the final Arkansas regional haze FIP should provide EAI with the option for the White Bluff coal-fired units of either meeting an emission limitation of 0.06 lb SO_2/mmBtu on a 30-boiler operating day average, or a binding requirement that (1) one unit will cease operation by the end of 2025 and the other unit by the end of 2026, and (2) one unit will be limited to a capacity factor of no greater than 50 percent in 2025.

Further, the most recent IMPROVE data provided in Exhibit 2 demonstrate that visibility already is better in Arkansas' Class I areas than the URP goals, Arkansas' RPGs or EPA's proposed RPGs for the first planning period. As a result, no additional controls are necessary to make reasonable progress towards reducing visibility impairment at the two Arkansas Class I areas for the first planning period.

The information in these Supplemental Comments and attached Exhibits, which was not available during the comment period on the proposed FIP, is current and highly relevant as it goes to three of the issues at the core of the rulemaking–the SO_2 BART determination for White Bluff, the NOx BART limits for White Bluff, and the need for reasonable progress controls during the first planning period. Accordingly, EAI respectfully requests that EPA include these Supplemental Comments and attached Exhibits in the administrative record for the Proposed FIP and incorporate this information into the Agency's analysis of SO_2 and NOx BART for White Bluff and the reasonable progress requirements for the first regional haze planning period.

UPDATE TO THE BART FIVE FACTOR ANALYSIS
FOR WHITE BLUFF STEAM ELECTRIC STATION UNITS 1 AND 2
REDFIELD, ARKANSAS (AFIN 35-00110)

Prepared By:

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Trinity Project No. 163701.0067

August 8, 2016

Update to the BART Five Factor Analysis for White Bluff Steam Electric Station Units 1 and 2

This report contains updated control cost calculations for the SO_2 and NO_X BART Five Factor Analyses for White Bluff Units 1 and 2 (SN-01 and SN-02). The update is necessary to consider new information regarding the remaining useful life ("RUL") of the units,[1] which affects the capital recovery period for the proposed BART controls, i.e., for SO_2 control, Spray Dryer Absorber technology ("SDA"). This new information was not available when the *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* was submitted on October 15, 2013.

EAI anticipates one of the two coal-fired units will cease operating in 2025 and the other unit in 2026. Based on FIP promulgation in 2016 and a five-year compliance timeline, this means that whichever unit ceases operations in 2025 would have an RUL of four (4) years and the other unit would have an RUL of five (5) years. Additionally, one of the units will operate at a capacity factor (CF) of no greater than 50 percent in the year 2025. Together, the RULs and CF limitation are referred to herein as "the operation restrictions".

Updated SO_2 Control Costs

The update to consider the operation restrictions results in average cost effectiveness values for SDA of between approximately \$10,400 and \$11,800 per ton of SO_2 removed depending on which of the two units has an RUL of four years and which has an RUL of five years. This entire range of average cost effectiveness is infeasible as BART.

The updated emissions and cost effectiveness calculations for SDA based on the operation restrictions are presented in Table 1 and Table 2 for Unit 1 and Unit 2, respectively. The emissions information and capital and O&M cost estimates are based on Sargent & Lundy's 2015 report.[2] Using instead the emissions information and capital and O&M cost estimates from EPA's proposed FIP Technical Support Document, Appendix A, the average cost effectiveness estimates for SDA are between approximately \$5,000 and \$5,900 per ton of SO_2 removed. Summaries of these estimates are shown in Tables 3 and 4. Even these unrealistic and artificially low cost values are also economically infeasible.

[1] Remaining useful life is one of five factors to be considered in the BART impact analysis. The other four factors are cost of compliance, energy impacts, non-air quality environmental impacts, and visibility improvement.
[2] Sargent & Lundy LLC, *Entergy Arkansas, Inc. - White Bluff Dry FGD Cost Estimate and Technical Basis*, Report No. SL-012831 (July 2015)(Exhibit B to EAI's Comments on the proposed FIP).

Table 1. SDA Cost Effectiveness - White Bluff Unit 1

Baseline Emission Rate (tpy)	15,939	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,675	
Emissions Reduction (tpy) [1]	14,264	13,414
Total Capital Investment ($)	536,185,000	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	158,296,888	130,770,532
Direct Variable and Fixed O&M Costs ($/yr) [2]	10,166,000	9,560,422
Total Annual Costs ($/yr)	168,462,888	140,330,954
Cost Effectiveness ($/ton)	11,810	10,461

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Table 2. SDA Cost Effectiveness - White Bluff Unit 2

Baseline Emission Rate (tpy)	16,034	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,681	
Emissions Reduction (tpy) [1]	14,353	13,490
Total Capital Investment ($)	536,185,000	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	158,296,888	130,770,532
Direct Variable and Fixed O&M Costs ($/yr) [2]	10,166,000	9,555,003
Total Annual Costs ($/yr)	168,462,888	140,325,535
Cost Effectiveness ($/ton)	11,737	10,402

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Table 3. SDA Cost Effectiveness - White Bluff Unit 1 ***Using FIP Information***

Baseline Emission Rate (tpy)	15,816	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,453	
Emissions Reduction (tpy) [1]	14,363	13,534
Total Capital Investment ($)	247,537,295	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	73,079,969	60,372,043
Direct Variable and Fixed O&M Costs ($/yr) [2]	12,029,724	11,335,696
Total Annual Costs ($/yr)	85,109,693	71,707,739
Cost Effectiveness ($/ton)	5,926	5,298

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Table 4. SDA Cost Effectiveness - White Bluff Unit 2 ***Using FIP Information***

Baseline Emission Rate (tpy)	16,697	
Controlled Emission Level (lb/MMBtu)	0.06	
Controlled Emission Rate (tpy)	1,476	
Emissions Reduction (tpy) [1]	15,221	14,266
Total Capital Investment ($)	247,537,295	
Interest Rate (%)	7	
Capital Recovery Period = RUL (Years)	4	5
Capital Recovery Factor (CRF)	0.295	0.244
Annualized Capital Costs ($/yr)	73,079,969	60,372,043
Direct Variable and Fixed O&M Costs ($/yr) [2]	12,029,724	11,275,230
Total Annual Costs ($/yr)	85,109,693	71,647,273
Cost Effectiveness ($/ton)	5,592	5,022

[1] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emissions reduction adjustment.

Updated NO_X Control Costs

Consideration of the operation restrictions results in NO_X control cost effectiveness estimate changes as summarized in Table 5. The proposed BART control technology remains LNB+SOFA as presented in the October 15, 2013 *Revised BART Five Factor Analysis – White Bluff Steam Electric Station* at the emission rates presented in EAI's August 8, 2016, supplemental comments.

Table 5. NOx Controls Cost Effectiveness

	Baseline Emission Rate	Controlled Emission Level	Controlled Emission Rate [1]	NOx Reduced	NOx Reduced for 5-Year RUL [2]	Capital Cost	Annualized Capital Cost, 4-year RUL	Annualized Capital Cost, 5-year RUL	Annual O&M Cost, 4-year RUL	Annual O&M Cost, 5-year RUL [3]	Total Annual Cost	Average Cost Effectiveness	Incremental Cost Effectiveness
	(tpy)	(lb/MMBtu)	(tpy)	(tpy)	(tpy)	($)	($/yr)	($/yr)	($/yr)	($/yr)	($/yr)	($/ton)	($/ton)
SN-01 LNB/SOFA	7,249	0.15	4,145	3,104	2,919	10,461,206	3,088,442	2,551,391	319,887	300,831	2,852,222 - 3,408,329	977 - 1,098	
SN-01 LNB/SOFA/SNCR	7,249	0.13	3,592	3,657	3,439	21,371,325	6,309,416	5,212,267	4,849,000	4,560,150	9,772,417 - 11,158,416	2,842 - 3,051	13,314 - 14,022
SN-01 LNB/SOFA/SCR	7,249	0.055	1,520	5,729	5,388	230,329,138	67,999,638	56,175,134	3,444,000	3,238,844	59,413,978 - 71,443,638	11,027 - 12,470	22,910 - 29,087
SN-02 LNB/SOFA	8,185	0.15	4,060	4,125	3,877	14,488,206	4,277,326	3,533,539	312,838	294,036	3,827,575 - 4,590,164	987 - 1,113	
SN-02 LNB/SOFA/SNCR	8,185	0.13	3,519	4,666	4,386	25,398,325	7,498,300	6,194,415	4,853,000	4,561,325	10,755,740 - 12,351,300	2,452 - 2,647	13,615 - 14,336
SN-02 LNB/SOFA/SCR	8,185	0.055	1,489	6,697	6,294	206,747,898	61,037,793	50,423,889	3,466,000	3,257,686	53,681,575 - 64,503,793	8,529 - 9,632	20,626 - 25,688

[1] The future annual heat input was estimated by multiplying the average hourly heat input from CAMD for 2009-2011 for each boiler by the average number of operating hours for each boiler from 2009-2011.

[2] A 50 % capacity factor (CF) during 2025 is incorporated by subtracting from the 5-year RUL annual-average reduction value an amount equal to the annual-average reduction value scaled from the baseline CF to 50 %.

[2] Annual O&M costs are adjusted, assuming a linear relationship, to reflect the 50 % capacity factor during 2025 using the same method described above for the emission emissions reduction adjustment.

ASSESSMENT OF RECENT CLASS I AREA IMPROVE MONITORING DATA

Prepared By:

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Trinity Project No. 163701.0059

August 8, 2016

Assessment of Recent Class I Area IMPROVE Monitoring Data

Since the August 7, 2015 submittal of Trinity Consultant's *Regional Haze Modeling Assessment Report – Entergy Arkansas, Inc. – Independence Plant* (Trinity's report), measured concentration data for January 2014 through September 2015 from the Interagency Monitoring of Protected Visual Environments ("IMPROVE") network of Class I area monitors has become available. It is prudent to review this data for the two Arkansas Class I areas – Caney Creek ("CACR") and Upper Buffalo ("UPBU") – to determine if the trends identified in Trinity's report continue.

A summary of all available haze index values – from 2002 through 2015 (average of first nine months) – are shown in the following tables. As explained in Trinity's report, the IMPROVE equation is applied to the concentration data to calculate light extinction (Mm^{-1}), and then light extinction is converted to haze index (dv).

Table 1. Haze Indices for Caney Creek

Year	Observed 20% Worst Haze Index (dv)	Observed 20% Best Haze Index (dv)
2002	27.21	11.88
2003	26.54	10.74
2004	25.34	11.11
2005	29.21	12.93
2006	25.68	12.51
2008	23.70	9.24
2009	22.68	8.09
2010	22.94	10.76
2011	22.67	11.71
2012	21.49	9.54
2013	21.35	8.61
2014	20.72	8.52
2015	20.67	8.35

Table 2. Haze Indices for Upper Buffalo

Year	Observed 20% Worst Haze Index (dv)	Observed 20% Best Haze Index (dv)
2002	26.74	12.83
2003	27.22	10.62
2004	25.58	10.74
2005	30.47	13.34
2006	25.42	13.00
2007	26.17	12.45
2008	24.60	10.49
2009	22.62	9.40
2011	23.21	11.51
2012	21.56	10.31
2013	21.25	8.60
2014	20.49	8.13
2015	20.45	7.81

The following figures illustrate how these measured values compare to the Uniform Rate of Progress ("URP") curves for each area. The figures are updates to Figures 3-3 and 3-4 of Trinity's report, and, as such, also show the projected haze index values based on the scenario-specific modeling summarized in Trinity's report.

Figure 1. Caney Creek Observed Haze Index, Uniform Rate of Progress, and Projected Haze Index

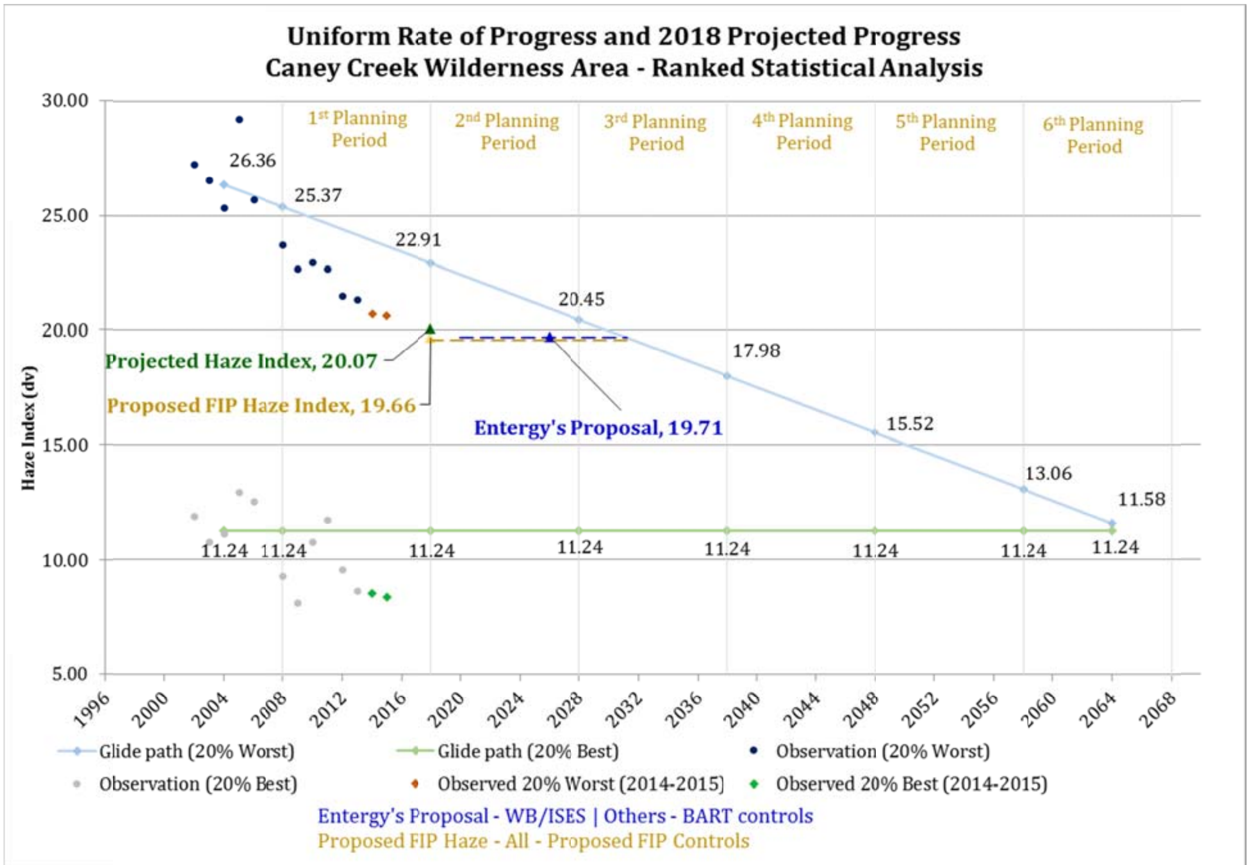
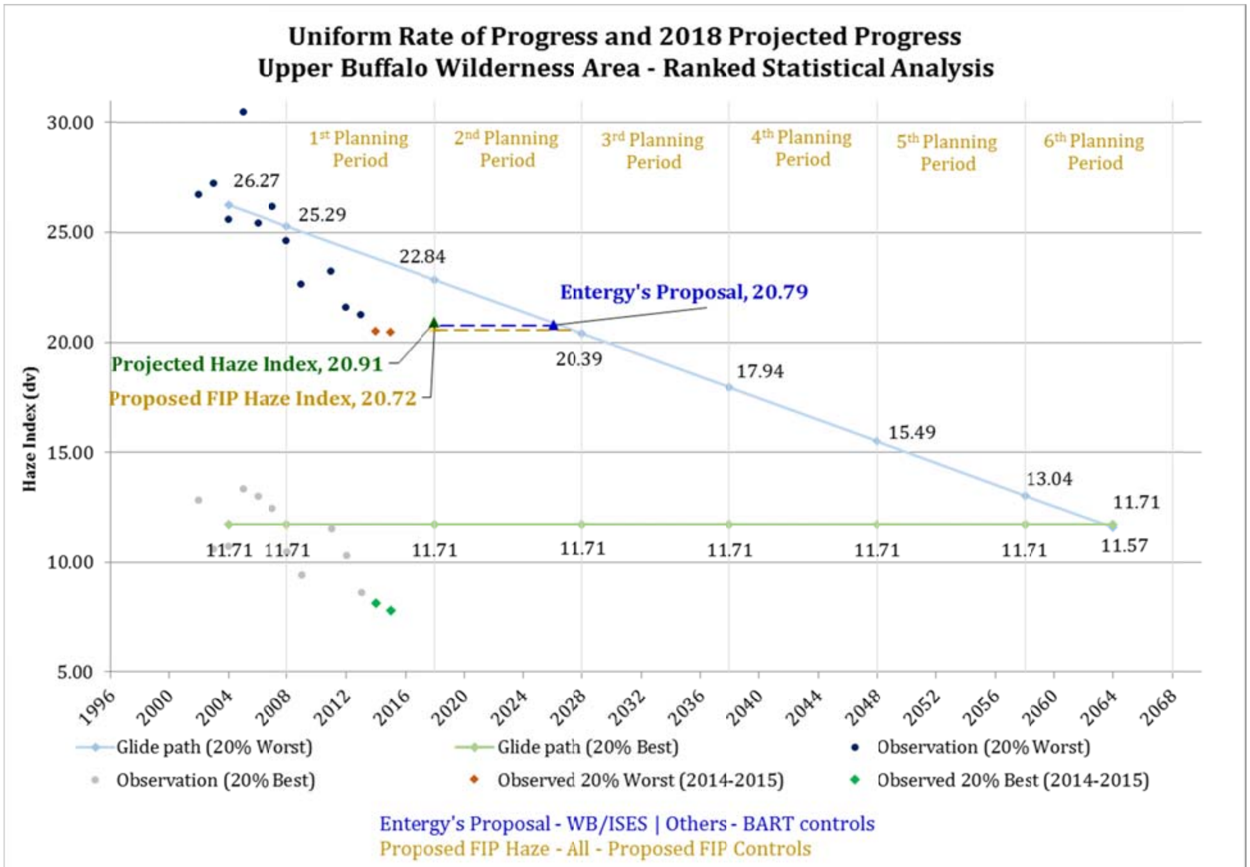


Figure 2. Upper Buffalo Observed Haze Index, Uniform Rate of Progress, and Projected Haze Index



As shown above, the actual visibility impairment at CACR and UPBU have continued to decrease through September 2015. The average 20 percent worst haze indices for CACR decreased from 21.49 dv in 2012 to 20.67 in 2015. Similarly, visibility improved at UPBU, where the average 20 percent worst haze indices decreased from 21.56 dv in 2012 to 20.45 dv in 2015. As shown in the figures and table below, these values are significantly less than (i.e., better than), and ahead of schedule of, the Reasonable Progress Goals (RPGs) proposed by ADEQ[1] of 22.48 dv by 2018 for the 20 percent worst days at CACR and 22.52 dv by 2018 for the 20 percent worst days at UPBU, and those proposed by EPA[2] of 22.27 dv for CACR and 22.33 dv for UPBU.

Table 3. 2018 Reasonable Progress Goals Compared to 2015 Visibility for the 20 % Worst Days

Class I Area	ADEQ-Proposed RPG for 2018 (dv)	EPA-Proposed RPG for 2018 (dv)	Actual Visibility in 2015 (dv)
Caney Creek	22.48	22.27	20.67
Upper Buffalo	22.52	22.33	20.45

[1] Arkansas's 2008 Regional Haze State Implementation Plan (SIP).
[2] April 18, 2015 proposed Arkansas Regional Haze Federal Implementation Plan (FIP).

Figure 3. Caney Creek Observed Haze Index, 20% Worst Days, and Proposed Reasonable Progress Goals

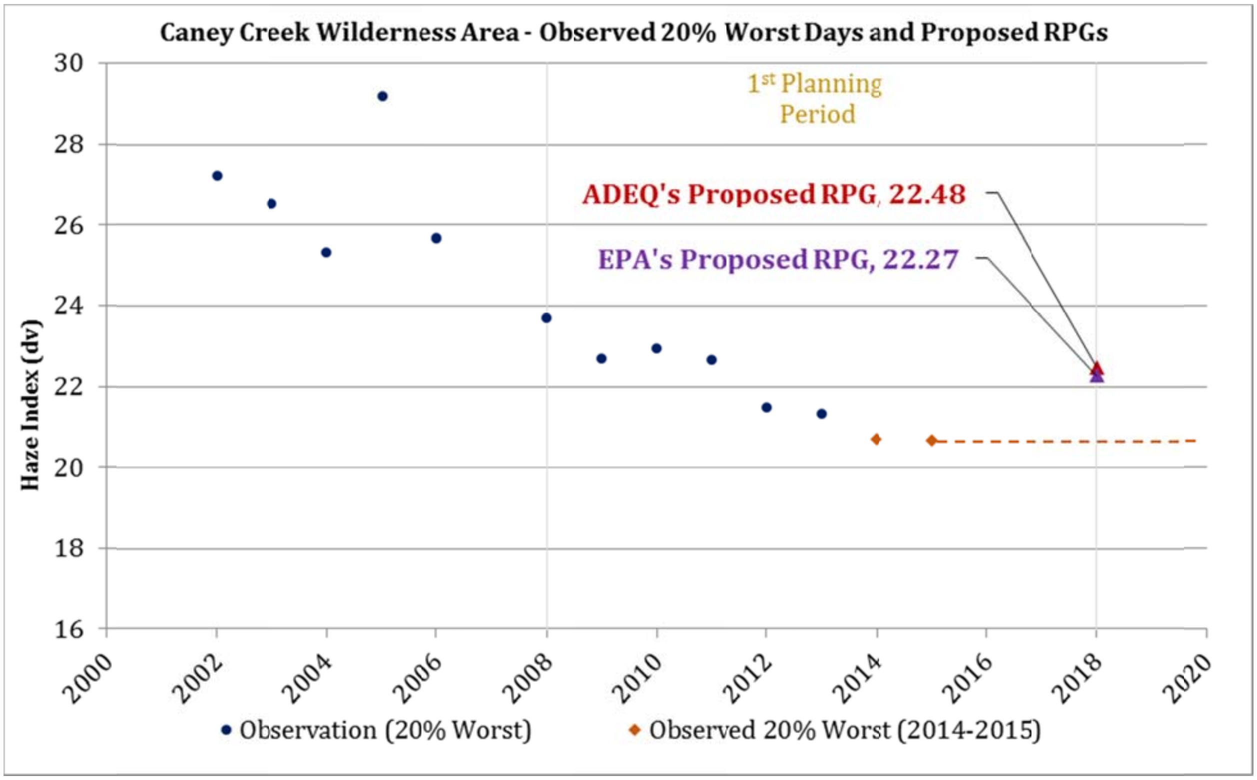


Figure 4. Upper Buffalo Observed Haze Index, 20% Worst Days, and Proposed Reasonable Progress Goals

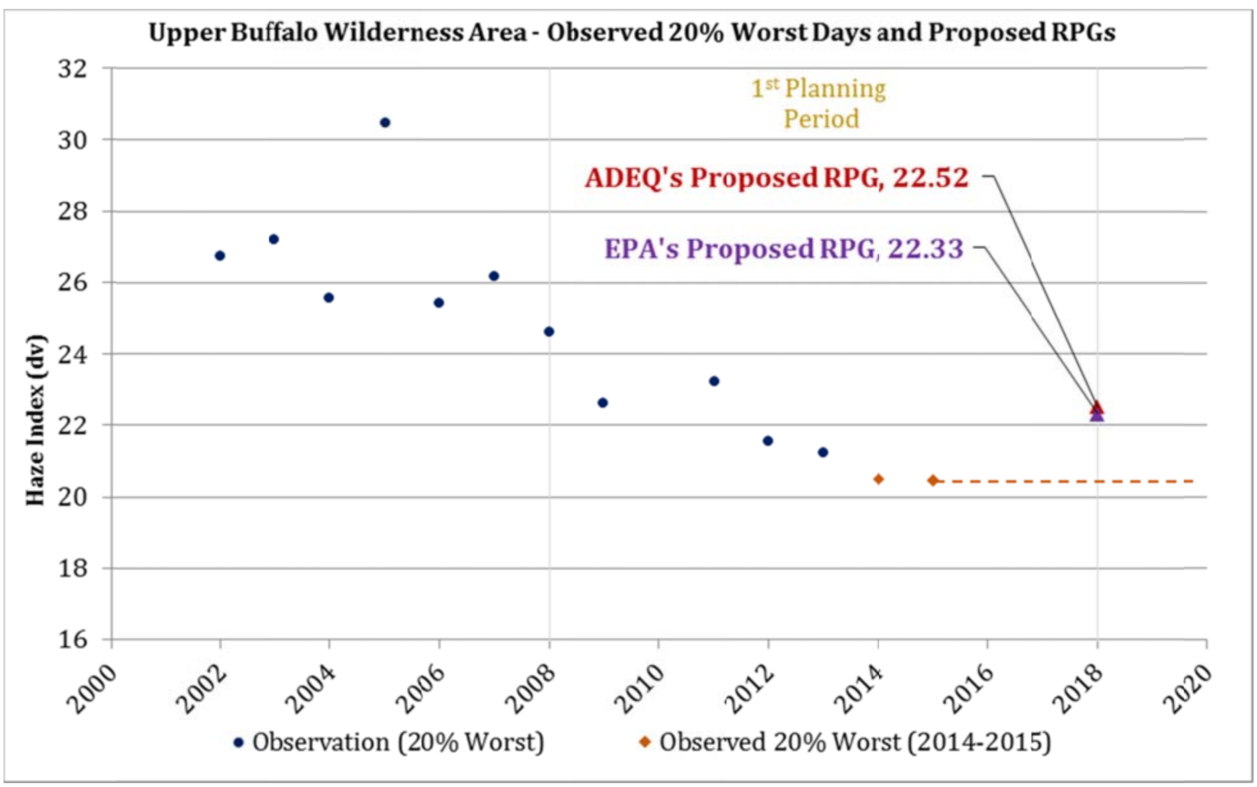


Exhibit 2 to EAI Supplemental Comments