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Revised Draft Final Report

EMISSIONS CONTROL PROJECT

Plants Evaluated:

Independence
White Bluff

REDACTED

for

Entergy

Houston, Texas

by

Washington Group International
Integrated Engineering, Construction, and Management Solutions

Project No. 27447-012

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Table of Contents

Section **Page No.**

EXECUTIVE SUMMARY ES-1

INTRODUCTION 1

2 STUDY APPROACH AND METHODOLOGY 3
- 2.1 STUDY BASIS 3
- 2.2 FGD, NOX AND HG CONTROL PROCESS SELECTION 4
- 2.3 CONCEPTUAL ENGINEERING 4
- 2.4 EMISSIONS CONTROL TECHNOLOGY EVALUATIONS 5
- 2.5 FINAL REPORT PREPARATION 5

3 DESIGN BASIS AND ECONOMIC CRITERIA 6
- 3.1 UNIT DESCRIPTIONS 6
- 3.2 DESIGN OBJECTIVES 6
- 3.3 GENERAL PLANT DESIGN INFORMATION 6
- 3.4 SO_2, NOX AND HG CONTROL ALTERNATIVES/DESIGN CRITERIA 12
- 3.5 TECHNOLOGY DESCRIPTIONS 12
- 3.6 ECONOMIC AND PERFORMANCE CRITERIA 61

4 PRELIMINARY EMISSIONS CONTROL PROCESS SCREENING 65
- 4.1 CONTROL TECHNOLOGIES SELECTED BY ENTERGY 65
- 4.2 REVIEW OF TECHNOLOGY SELECTION 69

5 SYSTEM MODIFICATIONS BY PLANT AND UNIT 76
- 5.1 FAN MODIFICATIONS 76
- 5.2 STRUCTURAL ENGINEERING ASSESSMENT 76
- 5.3 EQUIPMENT REMOVAL AND RELOCATION 76
- 5.4 ELECTRICAL SYSTEM TIE-INS 77
- 5.5 INSTRUMENTATION AND CONTROLS MODIFICATIONS 77
- 5.6 BOILER AND EXISTING FLUE GAS PATH IMPACTS 77
- 5.7 IMPACT ON EXISTING PLANT OPERATIONS 77

6 CONSTRUCTIBILITY ISSUES FOR EACH SITE 81

7 EMISSIONS CONTROL SYSTEM ECONOMIC ANALYSES 94
- 7.1 CAPITAL COST BASIS FOR CONTROL EQUIPMENT 94
- 7.2 OPERATING AND MAINTENANCE COST BASIS 95
- 7.3 EQUIPMENT SPARING PHILOSOPHY 96
- 7.4 RESULTS OF ECONOMIC ANALYSIS 96
- 7.5 SENSITIVITY ANALYES AND ALTERNATE SCENARIOS 99

APPENDICES 102

A	Control Technology Listing	A-1
B	Estimate Basis	B-1
C	Site Datasheets from Entergy	C-1
D	Cost Estimate Summary Sheets from IECCOST	D-1
E	Levelized and Operating Cost Breakdowns for Each Unit	E-1

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ETR_00000672

Table Listing

		Page #
ES-1	Cost Estimates for the Emissions Control Equipment at Independence Unit 1	ES-2
ES-2	Cost Estimates for the Emissions Control Equipment at Independence Unit 2	ES-3
ES-3	Cost Estimates for the Emissions Control Equipment at White Bluff Unit 1	ES-3
ES-4	Cost Estimates for the Emissions Control Equipment at White Bluff Unit 2	ES-4
ES-5	Cost Estimates for the Emissions Control Equipment at REDACTED	ES-4
ES-6	Economic Comparison of Combined Hg and SO_2 Control Systems	ES-8
ES-7	Additional CO_2 Emissions When Operating an LSFO FGD System	ES-9
ES-8	Low Sulfur Coal-fired Plants Using Wet FGD Systems	ES-10
1-1	Retrofit Impacts on Existing Balance-of-Plant Systems/Structures	2
3-1	Entergy Site Data Summary	7
3-2	Entergy Design Fuel Analyses	8
3-3	Entergy Coal-Fired Generating Unit Descriptions	9
3-4	Unit Operating Conditions for Design Basis	10
3-5	Control System Future Design Parameters	11
3-6	Selected Control Technology Operating Parameters	14
3-7	NOx Control Technology Limitations	53
3-8	TOXECON Design Criteria	55
3-9	Economic/Site Factors for Generating Stations	62
3-10	Operating Cost Criteria for Generating Stations	63
3-11	Emissions Allowances for Entergy Coal-fired Units	64
4-1	Operating Characteristics – Total for Each Plant Operating at 85% Average Load	66
4-2	Emissions Control Technology Limitations and Performance	69
4-3	Control Technology Design Criteria	70
4-4	'Desirable' Screening Analysis Summary for FGD Control Processes	73
4-5	'Desirable' Screening Analysis Summary for NOx Control Processes	74
4-6	'Desirable' Screening Analysis Summary for Mercury Control Processes	75
7-1	Cost Estimates for Emissions Control Equipment at Independence Unit 1	96
7-2	Cost Estimates for Emissions Control Equipment at Independence Unit 2	97
7-3	Cost Estimates for Emissions Control Equipment at White Bluff Unit 1	97
7-4	Cost Estimates for Emissions Control Equipment at White Bluff Unit 2	98
7-5	Cost Estimates for Emissions Control Equipment at REDACTED	98
7-6	LSD and FF Cost Breakdown for All Entergy Coal-fired Units	99
7-7	FGD Cost Estimates Without SO_2 Allowance Credits	100

Figure Listing

		Page #
3-1	LSFO Process Flow Diagram	16
3-2	Lime Spray Drying Process Flow Diagram	22
3-3	Circulating Fluid Bed Process Flow Diagram	28
3-4	Gas Path For SCR	31
3-5	Mobotec Flow Diagram	37
3-6	Process Flow Diagram for the TOXECON 1 System	56
3-7	TOXECON 2 Flow Diagram	56
3-8	TOXECON 1.5/COHPAC II Diagram	57
3-9	Coal Drying System Process Flow Diagram	60
3-10	Conceptual Design of Coal Dryer System	60
3-11	Photograph of the Pilot Dryer at the Coal Creek Plant	61
6-1	Ground Location for Carbon Injection Equipment and COHPAC at White Bluff	81
6-2	Potential Location for SCR Equipment at Independence	84

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ETR_00000673

6-3 Potential Location for FGD Equipment at White Bluff 85
6-4 Location of Lime or Limestone Preparation Area and Waste Dewatering at WB 85
6-5 Potential Locations of TOXECON and SCR at REDACTED 86
6-6 Ground Location for Carbon Injection Equipment and COHPAC at Independence 90
6-7 Potential Location for SCR Equipment at White Bluff 91
6-8 Potential Location for FGD Equipment at Independence 92
6-9 Potential Location of FGD Equipment at REDACTED 92
6-10 Potential Locations of Lime or Limestone Prep. Area & Waste Dewatering at IN 93
6-11 Potential Locations of Lime or Limestone Prep. Area & Waste Dewatering at NEL 93
7-1 Levelized Cost Sensitivity to Changes in SO_2 Removal Efficiency 101
7-2 Levelized Cost Sensitivity to Changes in Unit Size – Using Independence Data 101

ABBREVIATIONS AND ACRONYMS

Plant Designations
IN1 = Independence Station Unit 1
IN2 = Independence Station Unit 2
WB1 = White Bluff Station Unit 1
WB2 = White Bluff Station Unit 2
REDACTED

General:

ACI – Activated Carbon Injection
acf – Actual Cubic Feet
acfm – Actual Cubic Feet per Minute
AFUDC – Allowance for Funds Used During Construction
ANSI – American National Standards Institute
ASFO – Ammonium Sulfate with Forced Oxidation
ASTM – American Society for Testing and Materials
CFB – Circulating Fluid Bed
COHPAC – Compact Hybrid Particulate Collector
dscf – Dry Standard Cubic Foot
Entergy – Entergy Corporation
EPA – Environmental Protection Agency
EPRI – Electric Power Research Institute
ESP – Electrostatic Precipitator
F – Fahrenheit
FF – Fabric Filter
FGD – Flue Gas Desulfurization
HHV – Higher Heating Value
kWh –kilowatt-hour
LNB – Low NOx Burner
LSD – Lime Spray Dryer
LSFO – Limestone with Forced Oxidation
M – 1000
MCR – Maximum Continuous Rating
MMBtu – Million British Thermal Units
MW – Megawatt
NEC – National Electrical Code
NFPA – National Fire Protection Assoc
NOx – Nitrogen Oxides
OFA – Over Fire Air
PJFF – Pulse Jet Fabric Filter
SCR – Selective Catalytic Reduction
SNCR – Selective Non-catalytic Reduction
TCR – Total Capital Requirement
TPC – Total Plant Cost
tph – Tons per Hour
UBC – Uniform Building Code
w.g. – Water Gauge

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EXECUTIVE SUMMARY

This report presents the results of the Emissions Control Evaluation Study completed by Washington Group International for Entergy Corporation (Entergy). The report evaluates the control technologies that were selected by Entergy for potential retrofit onto the White Bluff Units 1 & 2, Independence Units 1 & 2 and REDACTED Some additional processes were included in the analysis based on their ~~potential to~~ be cost competitive alternatives. The technologies evaluated for each unit are summarized below:

- TOXECON 1, 1.5 and 2 for mercury control
- Limestone with Forced Oxidation (LSFO) for SO_2 Control
- Lime Spray Dryer (LSD) with PJFF for SO_2 control
- Circulating Fluid Bed (CFB) with PJFF for SO_2 control
- Selective Catalytic Reduction (SCR) for NOx control
- Selective Non-Catalytic Reduction (SNCR) for NOx control
- Mobotec Rotating Overfire Air for NOx control
- Low NOx Burners with Overfire Air (LNB/OFA) for NOx control
- Great River Energy Coal Drying Process

Washington Group estimated the capital and operating costs for the retrofit of each of these technologies (results provided in Section 7 and estimate backup material can be found in Appendix D). In addition, balance-of-plant impacts are discussed in Section 5 and the constructibility issues for these retrofits are discussed in Section 6.

The cost estimates for this study were based on a series of Design and Economic Criteria summarized in Section 3 of this report. The majority of this data was obtained directly from Entergy (see datasheets in Appendix C). Where the information was not readily available, Washington Group assumed utility industry average values in the estimating process. These industry averages were extracted from various Electric Power Research Institute publications.

Section 4 provides a discussion of the results and methodology for the selection of the various emissions control technologies. Entergy initially stated that they wanted to focus on commercially available systems, and a series of criteria were used to develop a qualitative assessment of each option to identify those technologies that might best meet the needs of Entergy at each site.

The retrofit of these emissions control systems will impact other plant systems:

- Fan upgrade requirements
- Structural support and site geotechnical conditions
- Demolition/relocation of existing structures and underground interferences will be addressed in the detailed design
- Power supply connection to the existing plant electrical system
- Tie-ins to other utilities (water, steam, waste handling, etc.)
- Instrumentation and control tie-ins to the existing plant control system
- Air preheater upgrade requirements to handle the new operating conditions

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ETR_00000675

- Impact on existing plant operations

Results of the economic analyses are provided in Section 7. The intent of the cost estimating effort was to provide Entergy with capital and operating costs that they could use to determine the expected cost impact for each modification under consideration. For mercury removal, the activated carbon injection (ACI) system is the only technology that has undergone sufficient full-scale field installation and testing to be considered ready for commercial installations. At least one company is currently offering process guarantees for ACI systems. For this analysis, three types of TOXECON designs have been considered:

- TOXECON 1 = ACI with COHPAC baghouse operating downstream
- TOXECON 1.5 = ACI upstream of a baghouse conversion in the last field of the existing ESP
- TOXECON 2 = ACI occurs between fields in the existing ESP with no baghouse.

The cost estimates developed for this study are summarized in the following Table ES-1 through ES-5 on a unit-by-unit basis. Cost estimates for the retrofit of the control equipment on a plant basis are provided in Appendix D. Breakdowns of the levelized and first-year operating costs are also provided at the end of Appendix D, showing the contribution of the various fixed and variable operating cost components. Cost estimates that do not consider the credit for excess emissions allowances can be found in Section 7.5 of this report, along with cost sensitivity analyses versus various design and operating parameters.

Table ES-1. Cost Estimates for Emissions Control Equipment at Independence Unit 1

Process	Capital Cost (million $)	Capital Cost ($/kW)	Levelized Cost* ($/ton or lb. removed)
FGD Systems			
LSFO	$79	$94	$500/ton SO_2
Lime Spray Dryer (with PJFF)	$124	$148	$800/ton SO_2
Circulating Fluid Bed (with PJFF)	$107	$128	$700/ton SO_2
NOx Control System			
SCR	$78	$94	$2,300/ton NOx
SNCR	$8.6	$10	$900/ton NOx
Mobotec	$14.6	$17	$1,100/ton NOx
LNB with OFA	$21	$25	$600/ton NOx
Hg Control Systems			
TOXECON 1	$36.4	$44	$36,000/lb Hg
TOXECON 1.5	$34.9	$42	$74,000/lb Hg
TOXECON 2	$10.6	$13	$61,000/lb Hg

*Levelized costs include a credit for the SO_2 allowances generated. IN1 = 16,910/year for LSFO and 16,160/year for dry scrubbing systems starting in 2008. Sold for $500/allowance.

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ETR_00000676

Table ES-2. Cost Estimates for Emissions Control Equipment at Independence Unit 2

Process	Capital Cost (million $)	Capital Cost ($/kW)	Levelized Cost ($/ton or lb. removed)
FGD Systems			
LSFO	$81	$96	$510/ton SO_2
Lime Spray Dryer (with PJFF)	$127	$151	$810/ton SO_2
Circulating Fluid Bed (with PJFF)	$110	$130	$710/ton SO_2
NOx Control System			
SCR	$78	$92	$2,000/ton NOx
SNCR	$8.7	$10	$800/ton NOx
Mobotec	$14.6	$17	$960/ton NOx
LNB with OFA	$21	$25	$520/ton NOx
Hg Control Systems			
TOXECON 1	$38	$45	$37,000/lb Hg
TOXECON 1.5	$36	$42	$77,000/lb Hg
TOXECON 2	$11	$13	$63,000/lb Hg

*Levelized costs include a credit for the SO_2 allowances generated. IN2 = 17,150/year for LSFO and 16,400/year for dry scrubbing systems starting in 2008. Sold for $500/allowance.

Table ES-3. Cost Estimates for Emissions Control Equipment at White Bluff Unit 1

Process	Capital Cost (million $)	Capital Cost ($/kW)	Levelized Cost* ($/ton or lb. removed)
FGD Systems			
LSFO	$78	$95	$420/ton SO_2
Lime Spray Dryer (with PJFF)	$123	$151	$740/ton SO_2
Circulating Fluid Bed (with PJFF)	$106	$131	$640/ton SO_2
NOx Control System			
SCR	$77	$94	$1,300/ton NOx
SNCR	$8.7	$11	$590/ton NOx
Mobotec	$14.4	$18	$610/ton NOx
LNB with OFA	$20.5	$25	$340/ton NOx
Hg Control Systems			
TOXECON 1	$36.5	$45	$27,000/lb Hg
TOXECON 1.5	$34.4	$42	$55,000/lb Hg
TOXECON 2	$10.6	$13	$45,000/lb Hg

*Levelized costs include a credit for the SO_2 allowances generated. WB1 = 19,750/year for LSFO and 19,030/year for dry scrubbing systems starting in 2008. Sold for $500/allowance.

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Table ES-4. Cost Estimates for Emissions Control Equipment at White Bluff Unit 2

Process	Capital Cost (million $)	Capital Cost ($/kW)	Levelized Cost ($/ton or lb. removed)
FGD Systems			
LSFO	$78	$92	$350/ton SO_2
Lime Spray Dryer (with PJFF)	$124	$147	$670/ton SO_2
Circulating Fluid Bed (with PJFF)	$107	$127	$560/ton SO_2
NOx Control System			
SCR	$77	$91	$1300/ton NOx
SNCR	$8.8	$10	$590/ton NOx
Mobotec	$14.6	$17	$620/ton NOx
LNB with OFA	$21	$25	$340/ton NOx
Hg Control Systems			
TOXECON 1	$37	$44	$27,000/lb Hg
TOXECON 1.5	$35	$42	$55,000/lb Hg
TOXECON 2	$11	$13	$45,000/lb Hg

*Levelized costs include a credit for the SO_2 allowances generated. WB2 = 22,690/year for LSFO and 21,960/year for dry scrubbing systems starting in 2008. Sold for $500/allowance.

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Mercury Control - The results of the mercury control analysis indicate that any of the carbon injection systems will be relatively expensive to install and operate at each plant in the Entergy system. The cost of control is likely to range from $27,000/pound of Hg collected at White Bluff Unit 1 to $77,000/lb. Hg at Independence Unit 1. The injection point for the TOXECON 1 activated carbon will require between 0.3 and 1 second of gas contact to complete the Hg absorption. Therefore, the specific location is not critical at this point in the conceptual design of these systems. Adequate injection locations should be available for all units. If lime spray dryer FGD systems were used, then the ACI injection location has to be upstream of the spray dryer vessels to maintain Hg removal performance. It should also be noted that including a fabric filter (FF) would provide additional gas/solid contact time, making the selection of the injection location relatively flexible in the final detailed design, and potentially reducing the activated carbon injection rate compared to units without fabric filters.

NOx Control System Retrofits – The retrofit installation of NOx control systems onto any of the Entergy coal-fired boilers will require consideration of many of the same construction issues that have faced every SCR, SNCR, or LNB/OFA retrofit. The impacts of these installations are discussed in the process description sections provided in Section 3.

NOx control at each of the Entergy units could use any of the systems evaluated in this study depending upon the future emission regulations that are applicable to the various Entergy plants. Each technology has its own performance limitations. SCR has demonstrated the capability to achieve the highest emission rate reductions of any system currently applied on coal-fired utility boilers. The existing plant layout at each site provides sufficient space close to the rear of the boiler in the areas next to the air heaters, upstream of the ESPs. It has been assumed that anhydrous ammonia can be used at all plants to supply the needs of the NOx control equipment. If permitting issues were identified in the future, then the anhydrous supply system could be replaced with aqueous ammonia or urea system to produce ammonia as needed at that site.

SO_2 Control - The costs for SO_2 control indicate that the dry scrubbing technologies are likely to have a higher capital investment and higher levelized control cost than the wet limestone FGD technology. This is due primarily to the fact that the analysis assumed that new FFs would be installed downstream of the dry scrubbing vessels to collect the FGD reaction products and improve SO_2 removal efficiency. Entergy is planning to fire low sulfur coal throughout the remaining plant life of all three plants.

The control options considered for SO_2 control at the Entergy coal-fired units included both wet and dry scrubbing alternatives. The following differences can be identified between wet and dry FGD system performance:

- Removal Efficiency - Wet systems can typically achieve slightly higher removal efficiencies than dry scrubbing, and the reagent costs are typically lower due to the cost differential between limestone and lime.

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- Reagent Feed Rates - To achieve high removal efficiencies in a dry scrubbing system, the lime feed rate must be higher than the limestone feed rate for a wet system designed to achieve similar performance.
- Flue Gas Outlet Temperature – The flue gas exiting a wet scrubber will be saturated with water vapor, and exit the absorber vessel at the gas saturation temperature that is typically around 127°F. A dry scrubbing system will operate at a pre-established approach to the saturation temperature, typically set at 30-35°F above the saturation temperature. This temperature differential is necessary in a dry scrubbing system to ensure that the solids exiting the reactor vessel are dry. Closer approach temperatures will allow the spray dryer system to achieve higher SO_2 removal efficiencies, but this comes with higher potential for solids dropout in the vessel and downstream ductwork, and for negative impacts on the particulate collection equipment downstream. If the system was operating at a 15-20 degree approach, and a system upset occurred, then wet solids could enter the baghouse and damage the fabric.
- Stack Plume – The lower temperature of the wet FGD system stack gases can result in a heavy steam plume at the stack exit during all ambient conditions. This plume will also have less buoyancy than higher temperature stack gases, resulting in the tendency to fold downward as it exits the stack. Some facilities have tried to reheat the flue gas after it exits the wet FGD system, and thereby maintain dry stack conditions. But these reheat systems are typically very expensive to operate and have a significant negative affect on the plant heat rate. Most wet FGD systems that have been installed since 1990 are designed to operate in a wet stack mode. Even those that installed gas reheat have disconnected these systems to both improve heat rate and to eliminate a system that typically requires significant maintenance attention.
- Sulfur Trioxide Removal – The dry FGD systems will remove most of the SO_3 produced during the combustion of coal. This operating trait is more important to those facilities that are burning medium to high sulfur coals. In these high sulfur cases, the wet scrubbers will only remove 10-50% of the inlet SO_3, and the SO_3 remaining in the flue gas can result in high stack opacity exiting the stack (acid mist plume). This issue should not be significant for any of the Entergy units that will be firing low sulfur, subbituminous coals.
- Aluminum Fluoride Blinding – Wet limestone systems can be subject to a chemical deactivation of their limestone feed if the upstream particulate collector fails to perform. In a scenario where the particulate collector experiences a major failure, then the fly ash entering the wet scrubber will end up in the scrubbing slurry (wet scrubbers typically collect 80-90% of the solids that enter them). Many ashes contain significant amounts of aluminum, and most coals contain sufficient fluoride to allow aluminum fluoride complexes to form. These compounds can coat the surface of the limestone particles and make them inactive for neutralization of sulfurous acids. Dry scrubbing systems are not subject to this deactivation chemistry.
- Impact on the Existing Particulate Collectors – The wet FGD systems will be installed downstream of the existing ESPs, so they will have no impact on this

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ETR_00000680

existing equipment operation. However, any LSD retrofit will result in an increase in the particulate loading, and it has been assumed that a new pulsejet FF will be required.

The CFB process vendors will sometimes install their reactor vessels upstream of the existing ESPs and still be able to achieve high SO_2 removal efficiencies. However, this would result in a contaminated fly ash, eliminating any future ash sales and increasing the landfill disposal volume by a factor of 2-3. Therefore, a FF was also included in the CFB system cost estimates. Some spray dryer suppliers (and most CFB vendors) prefer to operate with solids recycle, and others feel that this is not required for some low sulfur coal applications. Recycle can help to reduce the lime feed rate, but this will increases the flue gas grain loading exiting the dry scrubbing reactor. The actual solids grain loading to the new baghouse after the retrofit will depend on the design selected by Entergy.

The other primary impact on the baghouse will be the reduction in the gas temperature entering the new FF. The normal operating temperature for a FF is somewhere between 280-300°F. When operating downstream of a LSD, the inlet gas temperature will drop to approximately 160-170°F, increasing the potential for corrosion on internal surfaces.

Operating a LSD upstream of a FF will require the addition of a layer of insulation, especially around the access doors, to prevent condensation within the FF vessel. The plant will need to confirm the need to keep their existing fly ash separated from the waste solids generated by the LSD. Since all the coal-fired plants at Entergy currently sell significant portions of their fly ash, it was assumed that each plant would require an independent waste solids handling and storage system to support the particulate collector installed downstream of the LSD equipment.

LSD vs. LSFO Cost Comparison - It should be noted that based on the results of this analysis, the wet scrubbing option was found to be more cost effective than a LSD/FF retrofit. The primary reason for this result is the fact that the existing ESPs at the Entergy plants have sufficient collection area to meet current particulate emissions limits, and do not require replacement with a Fabric Filter. As a result, the wet LSFO system cost estimates do not include any allowance for additional particulate control when addressing SO_2 emissions. The addition of a downstream particulate collector to the LSD cost estimate results in costs that are 30-50% higher for the dry system vs. the wet LSFO FGD installations. One assumption that might influence the final comparison is if Hg controls were assumed to be necessary along with SO_2. In that scenario, a PJFF would be required for both cases. The comparison of this wet LSFO with TOXECON 1 vs. a LSD with activated carbon injection and a PJFF can be found in Table ES-6.

The LSD system was installed on many low sulfur coal-fired installations in the past. However, the number of wet FGD systems installed on low sulfur coal units was at least equal to the number of LSD installations. A listing of previous wet FGD installations on

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ETR_00000681

low sulfur coal-fired units is provided in Table ES-8. This listing includes recent installations and current projects that selected wet LSFO systems over lime spray dryers for low sulfur coal applications. The primary reasons that the LSD/FF system was found to be more expensive than the LSFO FGD retrofit at the Entergy units are the following:

- A PJFF was included in the cost of the LSD because it is required to collect the dry FGD reaction products and unreacted lime mixed with the fly ash. The LSFO system can operate efficiently downstream of the existing cold side ESPs.
- The cost of the lime reagent is much higher than limestone, and the stoichiometric feed rate (moles of CaO/Mole of SO_2 removed) is much higher than the feed rate for an LSFO system (moles of $CaCO_3$/mole of SO_2 removed).
- The size of the units at Independence and White Bluff result in multiple spray dryer vessels versus the use of a single LSFO vessel to handle all the flue gas generated by each unit. The maximum size for a LSD vessel that has been commercially demonstrated is approximately 350 MW, resulting in the need for three spray dryer vessels. LSFO absorber vessels have been installed up to 900 MW in size in the U.S., and at 1100 MW in units installed overseas. Therefore, a single vessel/unit installation is very feasible at White Bluff and Independence. At REDACTED only two LSD vessels would be required due to the smaller size of the unit, and as a result the cost comparison between the LSD/FF and LSFO system is closer. The multi-vessel designs are inherently more expensive due to the increase in complexity of the inlet and outlet ductwork, increased operating complexity, and higher installation costs for the multi-vessel installation.

Table ES-6. Economic Comparison of Combined Hg and SO_2 Control Systems

Process and Unit	Capital Cost (million $)	Capital Cost ($/kW)	Levelized Cost* (million $/year)
Independence 1			
LSFO + TOXECON 1	$115	$138	$24.1
LSD with PJFF and ACI*	$131	$157	$26.4
Independence 2			
LSFO + TOXECON 1	$119	$141	$24.9
LSD with PJFF and ACI*	$135	$160	$27.2
White Bluff 1			
LSFO + TOXECON 1	$114	$140	$21.8
LSD with PJFF and ACI*	$130	$159	$24.3
White Bluff 2			
LSFO + TOXECON 1	$115	$136	$20.5
LSD with PJFF and ACI*	$130	$156	$23

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ETR_00000682

CO_2 Production by FGD Systems – The chemistry of the LSFO FGD technology results in the release of one mole of carbon dioxide for each mole of SO_2 absorbed. This CO_2 is formed by the decomposition of the calcium carbonate molecule ($CaCO_3$) when it reacts with SO_2 to form calcium sulfite ($CaSO_3$). CO_2 makes up approximately 44% of the calcium carbonate (limestone), depending in part on the purity of the limestone. Therefore, for each ton of limestone consumed, 0.44 tons of carbon dioxide will be released. For the case of Independence operating at full load with an 85% capacity factor, this would result in the release of an additional 35,000 tons of CO_2 as the flue gas passes through the scrubber due to the decomposition of limestone during the SO_2 absorption reaction. Table ES-7 provides a summary of the expected emission rates for CO_2 due to the limestone decomposition, along with the projected annual cost of these emissions assuming a $7/ton emission allowance value in December 2004 dollars. The cost of theses allowances has been projected by Entergy to increase over time, reaching more than $14/ton in 2010, rising to more than $31/ton in 2020, and then retreating back to around $12/ton in 2027.

The LSD technology does not release CO_2 during the reaction of lime with SO_2. However, the production of lime is completed by heating limestone to 2000-2400°F to drive off the CO_2 in a kiln. One mole of CO_2 is released for each mole of limestone consumed in the kiln. In addition, heat must be added to the kiln to cause the decomposition of the calcium carbonate. The fuel burned in the kiln (3-6 million Btu/ton of lime produced) releases additional amounts of CO_2 into the atmosphere. The lime kilns also consume additional power in their drive motors that is approximately equal to 4 kW/ton of lime produced. Therefore, more CO_2 is released into the atmosphere for every mole of lime consumed than would be released in the LSFO scrubber when using limestone directly for SO_2 removal. The release point is just moved to the lime production plant.

Table ES-7. Additional CO_2 Emissions When Operating an LSFO FGD System (@100% load)

Unit	CO_2 Increase (tons/hour @ 100% Load)	Annual Allowance Value ($/year @ $7/ton)
Independence 1	2.35	$144,000
Independence 2	2.35	$144,000
White Bluff 1	2.12	$130,000
White Bluff 2	2.16	$132,000

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ETR_00000683

Table ES-8. Low Sulfur Coal-fired Plants Using Wet FGD Systems

Utility	Plant	Capacity (MW)	Design Coal Sulfur (wt. %)	Coal Type	FGD Type	Sorbent	FGD Startup Date
TXU Electric Company	Martin Lake 1	793	0.9	LIG/PRB	Spray	Limestone	1977
TXU Electric Company	Martin Lake 2	793	0.9	LIG/PRB	Spray	Limestone	1978
TXU Electric Company	Martin Lake 3	793	0.9	LIG/PRB	Spray	Limestone	1979
Western Resources Inc.	Jeffrey EC 1	720	0.3	PRB	Spray	Limestone	1978
Western Resources Inc.	Jeffrey EC 2	720	0.3	PRB	Spray	Limestone	1980
Western Resources Inc.	Jeffrey EC 3	720	0.3	PRB	Spray	Limestone	1983
Tri-State G&T Assn, Inc.	Craig C1	446	0.6	SUB	Spray	Limestone	1980
Tri-State G&T Assn, Inc.	Craig C2	446	0.6	SUB	Spray	Limestone	1980
Basin Electric Power Coop	Laramie River 1	570	0.8	PRB	Spray	Limestone	1980
Basin Electric Power Coop	Laramie River 2	570	0.8	PRB	Spray	Limestone	1981
Reliant Energy/Houston Lighting & Power	W A Parish 8	615	0.5	SUB	Spray	Limestone	1982
Texas Municipal Power Agency	Gibbons Creek 1	454	0.3	LIG/PRB	Spray	Limestone	1983
PacifiCorp	Hunter 3	446	0.6	BIT/SUB	Spray	Limestone	1983
Central Louisiana Elec. Co. Inc.	Dolet Hills 1	721	0.7	LIG	Spray	Limestone	1986
Deseret Generation & Tran. Coop	Bonanza 1-1	400	0.5	SUB	Spray	Limestone	1985
Los Angeles Department of Water & Power	Intermountain 1	820	0.6	BIT	Spray	Limestone	1986
Los Angeles Department of Water & Power	Intermountain 2	820	0.6	BIT	Spray	Limestone	1987
West Texas Utilities Company	Oklaunion 1	720	0.4	BIT	Spray	Limestone	1986
San Antonio Public Service Bd	J K Spruce FGD1	546	0.6	PRB	Spray	Limestone	1992
Public Service Company of New Mexico	San Juan 1	369	0.9	SUB	Spray	Limestone	1998
Public Service Company of New Mexico	San Juan 2	369	0.9	SUB	Spray	Limestone	1998
Public Service Company of New Mexico	San Juan 3	555	0.9	SUB	Spray	Limestone	1998
Public Service Company of New Mexico	San Juan 4	555	0.9	SUB	Spray	Limestone	1998
Salt River Project	Navajo 3	803	0.6(0.32 op.)	SUB	Spray	Limestone	1997
Salt River Project	Navajo 1	803	0.6(0.32 op.)	SUB	Spray	Limestone	1998
Salt River Project	Navajo 2	803	0.6(0.32 op.)	SUB	Spray	Limestone	1998
PacifiCorp	Centralia 1 and 2		0.9	BIT/SUB	Spray	Limestone	2000
Progress Energy	Asheville 1 & 2	212 & 205	0.7-1.2	BIT/SUB	Spray	Limestone	2005/2006
WE Energies/Wisconsin Electric	Pleasant Prairie 1 & 2	615 ea.	0.8	PRB	Spray	Limestone	2006/2007
Progress Energy	Roxboro 1,2,3,4	400-800 MW ea.	0.5-1.2	BIT/SUB	Spray	Limestone	2007/2010

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ETR_00000684

1 INTRODUCTION

The goal of this study is to provide Entergy with an analysis of the technical and economic impacts of retrofitting emissions control systems onto five coal-fired units located at three plants in Arkansas and Louisiana. The following objectives were established:

- Develop sizing criteria for the emissions control systems and associated auxiliary systems. Data will be gathered during plant visits by Washington Group staff and through data requests to Entergy.
- Establish the Design Basis criteria for each unit in the Entergy system.
- Establish the estimated pressure drop for modified ductwork and retrofit components. Evaluate the impact on the existing FD and/or ID fans.
- Develop capital and operating cost estimates using the conceptual designs formulated during the design effort. Washington Group historical data and in-house economic models will serve as the basis for these estimates. All costs are presented in December 2004 dollars.
- Balance of plant modifications and tie-ins to existing equipment will be included in the capital cost estimate as allowances for those scope items that are not sufficiently engineered in this conceptual design phase.

Table 1-1 provides a listing of the plant and site subsystems that were considered during this evaluation.

This Final Report is divided into the following sections:

1. Introduction - outlines the project scope of work, study objectives and contents of the report
2. Study Approach and Methodology - discusses the tools used and sequence of tasks that were completed in order to accomplish the goals defined for the project
3. Design Basis - establishes the basis for equipment selection/sizing and cost estimates
4. Economic Analysis – provides results of the cost estimating effort for all emissions control technologies at each site.
5. Conclusions – identifies the most cost-effective emissions control alternatives that are technically capable of achieving the performance requirements for each plant.

Appendices – provide the following support documents:

- A generic listing of technologies that have been previously offered for utility industry applications to flue gas emissions
- An estimate basis for the capital and operating costs that will be developed during the project.
- The site datasheets completed by Entergy for each site.
- Cost estimate output sheets from the IECCOST runs for each plant.

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000685

Table 1-1. Retrofit Impacts on Existing Balance-of-Plant Systems/Structures

Systems, Equipment & Structures	Retrofit Impact	Major Recommended Alterations
Plant Enclosures (if any)	Penetrations for ductwork and equipment access	Removal of sections of the walls with sufficient excess area to allow efficient construction access. Sealed at completion.
Control System Interface	Provide control signals to existing control rooms for each unit	Install panels in control rooms to provide control system operating conditions
Electrical System Tie-in	Add electrical components to provide power to the Control system and equipment	Install new MCC and transformer components as needed
I.D. Fans	Increased pressure drop across FGD control system may require fan upgrades or the installation of new ID booster fans	Depending upon the final pressure drop guarantee and fan evaluation, upgrade or replace existing fans
Waste Treatment	Waste disposal Contaminated ash disposal	Evaluate disposal or byproduct options – include equipment to process the products of the emissions control system
Compressed air system, including plant air and instrument air	Minimal impact – emissions control system typically has its own compressed air system	None
Potable water & sewage	Minimal impact due to added emissions control operating staff	None
Plant control room	Minimal impact; emissions control systems typically have an independent control system installed in existing control room	None
Plant office buildings	No impact	None
Plant Exterior Walls and Building Structural Steel	Structural load will increase on existing walls and on existing steel when new equipment is added for the emissions control equipment	Detailed seismic and structural analysis may be required to ensure that existing structure can handle new loads and to identify where upgrades are necessary.
Warehouse/maintenance Facilities	Some relocations of maintenance buildings possibly necessary	
Parking lot	Minimal impact	None
Boiler Structural Reinforcement	Reinforcement of the boiler and other gas path components can require the addition of a significant number of steel beams around the boiler and existing ductwork, etc.	Complete a pressure transient analysis as part of the detailed design effort
Water Makeup Sources	Identify new water sources to meet the FGD consumption	Attempt to permit additional consumption from existing sources

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2 STUDY APPROACH AND METHODOLOGY

The following section presents a description of the work performed by Washington Group International for this conceptual design and cost estimate study. The scope of work detailed below includes the identification of plant modifications required to retrofit emissions control systems onto the five coal-fired units in the Entergy system located at the three plants considered during this project. It also presents the detailed approach to accomplish each specific task, presents a sequence of activities for developing the information required to perform the work, and describes the work products produced during each task.

2.1 Study Basis

A Design Basis document was developed and reviewed by Entergy to ensure that the study criteria that will be used to evaluate the emissions control retrofit alternatives for each unit were accurate. The following tasks were completed to assist in the development of the Design Basis criteria:

Attended Project Review Meetings and Site Walk-downs

During August 2004, Washington Group personnel attended project kickoff/review meetings and site walk downs at the three coal-fired plants in the Entergy system. The primary purpose of these visits was to obtain relevant plant operating data and to review the scope of work with Entergy personnel, confirming the study objectives, approach, and schedule.

The data gathering effort obtained available information regarding both design and operating conditions for the following equipment and systems at each plant:

- Boiler Operating Conditions
- Burners and Fuel Projections
- Air Heaters
- Draft System
- Existing Pollution Control Equipment
- Plant Auxiliary Systems

The plant visits by Washington Group's engineering staff focused on gathering the remaining information required to perform the study. Data sheets completed by Entergy for each plant can be found in the Appendix.

Photography of the existing site equipment along with plot plans and arrangement drawings provided the basis for selection of the location of new control equipment. Further site investigations (particularly underground piping and foundation obstructions) would be required prior to completing the detailed design of the emissions control system installations for each unit.

Develop Study Basis

Under this task, Washington Group compiled data to complete the Project Design Basis that served as the foundation for the rest of the work. This document summarized all the design and economic criteria. A draft copy of this document was transmitted to Entergy for review in the third week of August 2004. Comments received were incorporated into the final document prior to proceeding with the site-specific evaluations. The Design Criteria used for the emissions

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ETR_00000687

control process evaluations are summarized in Section 3 of this report. The Design Basis includes unit- and plant-specific information for all coal-fired boilers in the Entergy system were summarized, including fuel analyses, flue gas flow rates, unit ratings, emission limits, heat rates, etc. (see datasheets in Appendix). This document also presents system performance requirements for the emissions control systems based on the future regulatory requirements specified by Entergy.

2.2 Emissions Control Process Selection

Initially Washington Group compiled a comprehensive list of available technologies for reduction of SO_2, NOx, and mercury. A group of Mandatory Criteria were developed to reduce this list to a set of approximately five viable processes for each pollutant that were considered for installation at each Entergy site. This list of possible technologies was further reduced to 1-3 processes for each pollutant and plant; these systems were evaluated in more detail. This selection process used a series of Desirable Criteria to identify those systems that are both technically feasible and appear to be the most cost-effective options to achieve system-wide compliance with future regulatory requirements. Entergy reviewed the listing of selected processes and added technologies of particular interest prior to Washington Group continuing with the conceptual analyses.

2.3 Conceptual Engineering

During conceptual engineering, calculations and analyses were performed to define the modifications that would be necessary to successfully retrofit the emissions control systems, as described in the following sections.

Prepare Combustion Calculations

Washington Group prepared combustion calculations to establish the flue gas properties that directly affect the size of major equipment in each control system (e.g., vessels, pumps, ductwork, dampers, et al. depending upon the process being considered). In addition, the combustion calculations form the basis for the evaluation of impacts to the boiler draft fans and other existing subsystems.

Identify System Modifications

Washington Group prepared a list of modifications required to install controls on each Entergy boiler. The following plant systems were identified as possibly requiring modifications:

- Draft System
- Demolition and Relocation of Existing Facilities
- HVAC ductwork
- Lighting
- Cable Tray and Conduit
- Enclosure Siding
- Electrical and Control System
- Reagent Storage and Transfer Piping and Conveyors
- Structural Steel/Foundations
- Control System

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ETR_00000688

2.4 Emissions Control System Evaluation

Capital Cost Estimates

Washington Group prepared capital cost estimates for the alternative control technologies at each unit. All costs are expressed in September 2004 dollars and represent the total installed cost including:

- Mechanical equipment
- Ductwork and structures
- Electrical equipment
- Instrumentation and controls
- Piping
- Miscellaneous buildings
- Site work and foundations
- Engineering
- Construction management
- Escalation
- Contingency

Equipment List and Power Consumption Estimates

Washington Group prepared lists of major equipment and estimated the auxiliary power consumption for each control system retrofit along with other plant modifications.

2.5 Final Report Preparation

This draft report documents the plant modifications required for the retrofit of emissions controls at the Entergy plants and presents the results of the conceptual design and cost estimating effort. Comments received from Entergy will be incorporated into the technical and economic analyses, and then the report will be reissued in final form.

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ETR_00000689

3 DESIGN BASIS AND ECONOMIC CRITERIA

3.1 Unit Descriptions

Three plants in the Entergy system were included in the analysis, consisting of five coal-fired, steam-generating units with a combined maximum continuous rating of 3,837 MW. The units went on line during the period from 1980-1984.

Fuel capabilities of each unit are provided later in this section. All units fire primarily low sulfur coals. Descriptions of each unit are provided in Table 3-3.

3.2 Design Objectives

The retrofit of the emissions control systems at the Entergy plants must meet the following objectives:

- In the first case, SO_2, NOx and mercury emissions were based on achieving potential EPA regulations as agreed to with Entergy. The analysis was on a unit-by-unit basis.
- Other emissions were limited to current values, or to permissible limits as determined to comply with State and EPA regulations.
- Control system alternatives were identified that exhibit the lowest evaluated levelized cost of control ($/quantity of pollutant removed) required for the system retrofits.
- Unit performance (e.g. capacity, efficiency, availability, and ramp rate) impacts were minimized and current operation was maintained to the extent possible.

3.3 General Plant Design Information

Site Data: Site descriptions are summarized in Table 3-1.

Access: Road and rail accesses availability are summarized in Table 3-1.

Fuel Analysis - The fuel analyses listed in the following tables will be used as the design fuels for each unit. The fuels presented in Table 3-2 were selected based on the projections provided by the Entergy Fuels Department. The emissions control system designs include the ability to handle the range of fuel properties as noted. Design coal ultimate analyses for each unit/plant are presented in Table 3-2. The analyses of typical supplemental fuels (natural gas and fuel oil) are also provided.

Emission Limitations

NOx, SO_2, and Hg Emission Limits – The design basis for the current emission rates is critical to the final analysis of control options. Excess allowances generated during a year can potentially be banked, sold or transferred to another plant. This could result in a potential revenue stream for Entergy that could be used to offset the operating costs for the emissions control equipment. Current emission rates are provided in Table 3-3, and operating conditions are summarized in Table 3-4.

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ETR_00000690

Table 3-1. Entergy Site Data Summary

Parameter	Independence 1	Independence 2		White Bluff 1	White Bluff 2
Location (City/State)	Newark, AR	Newark, AR	REDACTED	Redfield, AR	Redfield, AR
Site Elevation (feet)	239	239		300	300
Seismic Zone (UBC Zone)	2A	2A		2	2
Soil Conditions	30-40 ft. clay w/ dense sand and gravel below – water table at 25'	30-40 ft. clay w/dense sand and gravel below – water table at 25'		Silty clay w/ sandy clay lenses – water table @ 300'	Silty clay w/ sandy clay lenses – water table @ 300'
Foundation Type (typical)	Deep Piling	Deep Piling		Deep Piling	Deep Piling
Ambient Temp. Range (°F)	10-120 (6" snow load)	10-120 (6" snow load)		20-120	20-120
Standard Conditions	60°F/29.92 in. Hg for gas flow calc's.	60°F/29.92 in. Hg for gas flow calc's.		60°F/29.92 in. Hg for gas flow calc's.	60°F/29.92 in. Hg for gas flow calc's.
Wind Load, mph	100 mph	100 mph		100 mph	100 mph
Boiler Design/Vendor	Tangential/CE	Tangential/CE		Tangential/CE	Tangential/CE
Furnace Design	Twin	Twin		Twin	Twin
Furnace Draft	Balanced	Balanced		Balanced	Balanced
Current Coal Source	North Antelope PRB + 10% spot Low S WY (biomass considered)	North Antelope PRB+ 10% spot Low S WY (biomass considered)		Black Thunder, Caballo, Jacobs Ranch, N Antelope (max. 8% ash)	Black Thunder, Caballo, Jacobs Ranch, N Antelope (max. 8% ash)
Supplemental Start-up Fuel	Fuel Oil (0.5%) (517,000 gallons)	Fuel Oil (0.5%) (656,000 gallons)		Fuel Oil (0.5% S) (868,000 gallons)	Fuel Oil (0.5% S) (493,000 gallons)
Natural Gas Available?	No	No		Yes	Yes
Transportation Option	Truck or Rail	Truck or Rail		Truck or Rail	Truck or Rail
Ammonia Availability	Truck or Rail Only	Truck or Rail Only		Pipeline On Site	Pipeline On Site
Existing Chimney	1000' Dual A36 Flues (50' 316 SS) Concrete	1000' Dual A36 Flues (50' 316 SS) Concrete		1000' Dual A36 Flues (50' 316 SS) Concrete	1000' Dual A36 Flues (50' 316 SS) Concrete

*Mortar specification for brick liner mortar used on Nelson chimney indicates that the stack was built to ASTM C279 Type H standards

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000691

Table 3-2 Entergy Design Fuel Analyses (wt.% - wet basis as received)
Note: Data after "/" is typical from other studies for these fuels – used these analyses in cost estimates
(Note: Hg emission rates coming from EPRI Solutions test Program at Entergy plants)

	Independence		White Bluff	White Bluff Alternate
Coal Source	North Antelope	REDACTED	Black Thunder and other PRB coals	Antelope
Carbon	47.5/52.33		50.11/51.0	51.84
Hydrogen	3.38/3.67		4.11/3.50	3.48
Nitrogen	0.48/0.90		0.78/0.60	0.73
Chlorine	0.03/0.000/0.05		0.03/0.01	0.01
Sulfur (Typical)	0.5/0.33/0.21		0.41/0.32	0.20
Oxygen	14.31/11.84		18.06/12.0	11.97
Ash (Typical)	5.8/5.01/4.4		7.7/5.3	4.28
Moist. (Typical)	28/25.92/27.05		27.3/27.3	27.49
Btu/Pound (Typical)	8,800		8,400/8,800	8800
Mercury (ppm)	0.06		0.09	0.07

*Independence contains values from WGI average values, datasheets values and K. Cook data from e-mail 8/25/04.

Natural Gas	Average Vol. %	Range
CH_4	97.650	95.0 – 97.8
C_2H_6	0.630	0.51-0.80
C_3H_8	0.055	-
C_4H_{10}	0.010	-
C_5H_{12}	0.003	-
C_6	0.005	-
O_2	0.000	-
N_2	0.270	-
CO_2	1.390	1.36 – 1.75
CO	0.000	-
H_2	0.000	-
SO_2	3.77 ppm	-
HHV, Btu/SCF	1,004	1000 – 1030

#2 Fuel Oil	Average Wt. %	Range
C	83.75	83.0 – 86.0
H_2	12.60	-
S	0.18	0.17 – 0.50
N_2	0.27	0.27 – 0.35
O_2	0.63	0.33 – 0.93
Ash	0.0835	0.068 – 0.099
H_2O	0.10	-
Vanadium (ppm)	--	Up to 50
HHV, Btu/lb	18,560	18,400 – 19,200
Specific Gravity @ 60/60°F	0.9346	0.91 – 0.97
Viscosity SSU @ 122°F	591	130 - 2,250
Viscosity SSU @ 210°F	81.2	60 – 130

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ETR_00000692

Table 3-3. Entergy Coal-Fired Generating Units – Capacities and Emission Rates

Unit	Net Capacity (MW, Net)	Generation Capacity (MW, Gross)	First Year of Operation	Present Emissions Control	SO_2 Emission Rate (lb/mmBtu)	NOx Emission Rate (lb/mmBtu)	Hg Emission Rate (lb/Trillion Btu)**	Opacity Current/ Limit (%)	Part. Limit (lbs/mmBTU)
Independence 1*	836	880	1983	Cold ESP	0.335 CEM@500'	0.254 CEM@ 500'	5.7	6.5/20	0.04
Independence 2*	842	880	1984	Cold ESP	0.345 CEM@500'	0.290 CEM@500'	5.7	7.4/20	0.04

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White Bluff 1	815	880	1980	Cold ESP	0.69	0.35-0.45	7.8	7.5/20	0.1
White Bluff 2	844	880	1981	Cold ESP	0.68	0.31-0.45	7.8	12/20	0.1

*Independence installing turbine upgrade scheduled for fall of 2004 – no emissions increase expected. Also installing Connoisseur/Foxboro Neural Net to improve heat rate, lower NOx emissions, control soot blowing, control reheat and superheat temperatures, control air feed dampers and reduce CO_2 emissions. New low NOx burner retrofits may be considered in the future if emissions reductions below 0.15 lbs/MMBtu are required.

**From EPRI test results

Foundations and Soil Conditions:

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Independence – Water table is shallow (25'). A spotty transitional clay layer exists at various points around the site. Deep Piles required.

White Bluff – Water table at 300'below silty and sandy clay soil. Deep piles required.

Emission Control Efficiency Targets for Emission Reduction Evaluations:

Unit	NOx	SO_2	Hg
Independence	50-90%	95%	90%
White Bluff	50-90%	95%	90%

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ETR_00000693

Table 3-4 Unit Operating Conditions for Design Basis***

Unit	Study Capacity Factor (%)	2004 Aver. CF	NPHR* (Btu/kWhr)	Minimum Load (%)	Heat Input (mmBtu/hr	Fuel Burned (Current)	Econ. Outlet % O_2	Air Heater Inlet/Outlet °F
Independence 1	85	60.3	10,724	16.7 (test) 160-220 MW typ.	8967	Coal #2 Oil Startup	3	780/320 clean
Independence 2	85	75.8	10,661	16.6(test) 160-220 MW typ.	8976	Coal #2 Oil Startup	3	806/356 clean

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White Bluff 1**	85	62.69	10,823	17.1 (test)	8821	Coal #2 Oil Startup	3	759/347 clean
White Bluff 2**	85	75.05	10,615	16.6 (test)	8959	Coal #2 Oil Startup	3	750/344 clean

*Includes start-up fuel burned
**NOx emission rates tend to increase at White Bluff when operating at reduced load
*** Nearly 100% of the fly ash generated at all three plants is sold

Outages: Independence = minor (2-3 weeks) and major (4-6 weeks) maintenance outages scheduled on alternate years
White Bluff = minor (2-3 weeks) and major (4-6 weeks) maintenance outages scheduled on alternate years
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Services Available

- Service Water – process water quality assumed max. 150-ppm chloride
- Instrument/Service Air
- Electric Power
- For ash disposal costs, use EPRI TAG costs
- No spare fan capacity at any site

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ETR_00000694

Other Design Emissions Targets - In addition to the primary pollutant emission limits set by the EPA, Entergy will have the additional design target limits summarized below in Table 3-5:

Table 3-5. Control System Future Design Parameters

Opacity, %	20%
Particulate Matter, Gr/dscf	0.05 @12% CO_2
NOx, % Removal	0.125 lbs/MMBtu in 2015 Use 0.15 lbs/MMBtu for system designs*
SO_2, % Removal	92-95
Hg, % Removal	50, 70, and 90% (dates to be determined)
CO, ppm	No Increase
VOC, ppm	No Increase

*SCR costs will be provided for comparison to other options

Codes, Standards and Regulations

All equipment shall be designed, manufactured, installed and tested, where applicable, in accordance with all approved or accepted provisions of the following Codes, Standards and Regulations and as stated herein in effect at time of Contract award.

- AASHTO – American Association of State Highway and Transportation Officials
- ACI - 318 Building Code Requirements for Reinforced Concrete
- AISC - American Institute of Steel Construction
- AISI - American Iron and Steel Institute
- ASME/ANSI B16.5 - Pipe Flanges and Flanged Fittings
- ASME/ANSI B16.9 - Factory-Made Wrought Steel Buttwelding Fittings
- ANSI B16.11 - Forged Fittings, Socket-Welding and Threaded
- ASME/ANSI B16.25 - Buttwelding Ends
- ASME/ANSI B16.34 - Valves - Flanged, Threaded, and Welded End
- ASME B31.1 - Power Piping
- ASCE 7 - Minimum Design Loads for Buildings and Other Structures
- ASME Boiler and Pressure Vessel Code, Section I
- ASME Boiler and Pressure Vessel Code, Section VIII, Division 1
- ASME Boiler and Pressure Vessel Code, Section IX
- ASTM - American Society for Testing and Materials
- AWS - American Welding Society - Contractor qualifies all welding to the requirements of the ASME Boiler and Pressure Vessel Code Section IX
- AWWA - American Water Works Association
- CFR - Code of Federal Regulations, Title 29 - Labor, Chapter XVII Occupational Safety and Health Administration (OSHA), Parts 1910 and 1926
- EPA - Environmental Protection Agency

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000695

- FM - Factory Mutual
- ISA - International Society for Measurement and Control
- MSS SP84 - Steel Valves, Socket Welding and Threaded Ends
- NAAMM - National Association of Architectural Metals Manufacturer
- NACE – National Association of Corrosion Engineers
- NEC - National Electrical Code
- NFPA - National Fire Protection Association
- PFI Std. ES-21 - Manual Gas Tungsten Arc Root Pass Welding End Preparation and Dimensional Joint and Fit Up Tolerances
- SSPC - Steel Structures Painting Council
- TEMA - Tubular Exchanger Manufacturers Association
- UBC - Uniform Building Code
- UL - Underwriters' Laboratories, Inc.
- UPC - Uniform Plumbing Code

3.4 Emissions Control Alternatives

Emission control options for each unit are discussed briefly in the following section. The terms of the emission regulations and the unit operating projections over the next twenty years will directly impact the selection of control technologies for each facility. The economic analyses consider the application of the selected technologies based on their technical and economic feasibility for each unit.

Control systems selected by Entergy to-date include

- SO_2 – Wet Limestone with Forced Oxidation (LSFO)
  - Lime Spray Dryer (LSD)
- NOx – Advanced Over Fire Air (OFA) - Mobotec
  - Selective Catalytic Reduction (SCR)
  - Selective Non-catalytic Reduction (SNCR)
  - Low NOx Burners (LNB) with Over-Fire Air (OFA)
- Hg – TOXECON I - Activated Carbon Injection (ACI) with COHPAC (Compact Hybrid Particulate Collector)
  - TOXECON 1.5 – ACI with ESP Field Conversion to Fabric Filter (FF)
  - TOXECON II – ACI into the ESP Upstream of Last Field
- Coal Drying – Great River energy coal drying process – impacts on emissions

At this point, no other systems meet all the criteria established for the selection of viable systems. Most other developing technologies do not meet the requirement that they be commercially available and have been previously installed on large coal-fired utility boilers.

It should be noted that Entergy has submitted a proposal with ADA to the DOE to conduct a full-scale demonstration of the TOXECON II technology on one of the Independence precipitators (installation of carbon injection upstream of the last field of the ESP). DOE selected this project for installation in 2004, and startup is scheduled for in the summer/fall of 2005. Descriptions of the control technologies will be included in the final report.

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ETR_00000696

3.5 Technology Descriptions

The following material provides brief descriptions of the control technologies selected for more detailed evaluation in this study.

Process Assessments

The advantages and disadvantages of these various emissions control systems are discussed below:

Wet LSFO FGD - SO_2 Removal Efficiency = Higher than 95% design is possible. Long-term average performance for any wet or dry FGD system is typically 2-3% lower than the design/performance test guaranteed removal efficiency.

- •PROs - High removal efficiency on entire flue gas flow
  - Commercially proven technology
  - LSFO enables better chemistry control; reduces scaling
  - Allows reuse of existing reagent/dewatering systems
- •CONs - Higher auxiliary power consumption than dry FGD when not considering the pressure drop across the FF (additional fan load)
  - Some degree of retrofit difficulty due to current plant configuration

Lime Spray Dryer and Circulating Fluid Bed FGD – SO_2 removal efficiency of 90-93%.

- •PROs – Removal efficiency on entire flue gas flow is high, but will be slightly lower than wet FGD
  - Commercially proven technology
  - LSD and CFB processes generate a dry waste product
  - LSD and CFB vessels can be constructed of unlined carbon steel
  - Lower auxiliary power consumption is expected compared to wet FGD
- •CONs - More expensive reagent required
  - Some degree of retrofit difficulty due to current plant configuration
  - Lower SO_2 removal capability than a wet scrubbing process
  - Higher reagent consumption rates
  - Use of LSDs and CFBs with new FFs will result in higher capital costs compared to wet scrubbing systems

Low NOx Burners with Overfire Air - NO_X removal efficiency = 30-55%

- •PROs - Commercially mature
  - Moderate removal efficiency
  - No reagent required
  - No change in net output
  - Good turndown
- •CONs - Increased carbon in ash could impact fly ash sales
  - Potential stack opacity impacts
  - Requires water wall penetrations for Over-Fire Air (OFA)
  - Requires routing of large ductwork for OFA
  - Increased water wall wastage due to reducing atmosphere

Selective Catalytic Reduction - NO_X removal efficiency = 70-90%

- •PROs - High removal efficiency
  - SCR technology is maturing, but still on the learning curve
  - Minimal impact on boiler operation
- •CONs - Highest cost
  - High pressure drop requires more fan and duct reinforcement

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- Reduces net output 1-2%
- Restricts turndown /economizer bypass needed
- Large footprint – limits access to backend
- High emissions during SCR outages
- Spent catalyst disposal
- Ammonia or urea stored on-site

Mobotec - NO_X Removal Efficiency = Up To 80% may be achievable using a combination of Rotating Overfire Air (ROFA) and Rotamix (SNCR urea/ammonia injection into furnace). However, Mobotec's experience with Rotamix on large boilers (greater than 300 MW capacity) is limited to less than one year of operation on a single unit, and this installation has not reached the projected performance. Mobotec is currently reevaluating their engineering design and performance projections for Rotamix on larger units:

•PROs - Lower cost than SCR per vendor claims
- Potentially high removal efficiency per vendor claims – currently limited to 50% reduction due to lack of experience applicable to larger units.

•CONs - Limited commercial experience
- Reports of performance shortfalls at some installations
- Requires high horsepower fans, consuming approximately 0.6% of the net plant power output
- Requires water wall penetrations
- Requires routing of ductwork in boiler house
- Ammonia or urea stored on-site (Rotamix only)
- Potential for water wall erosion from gas vortex generated in furnace

Activated Carbon Injection - Mercury Removal Efficiency = 20-90%

•PROs - High removal efficiencies depending on sorbent feed rate
- May define mercury MACT

•CONs - High cost for mercury removal
- Expensive sorbent and possibly accelerated wear of fabric
- Reduces net output by about 1%
- May result in a minor increase in FF pressure drop
- Limited commercial experience

Table 3-6. Selected Control Technology Operating Parameters

SO_2	Technology Selected	Chem. And Waste	Power and Water	SO_2 Removed
	LSFO	Limestone Gypsum Waste	1-1.5% Plant MW 0.6-1.2 gpm/MW ≈1 gpm H_2O/MW	95%
	LSD and CFB	Lime Lime/Ash Waste	0.5-1.2% Plant MW 0.5-1.1 gpm/MW <1 gpm H_2O/MW	92%
NOx	**Technology Selected**	**Chem. And Waste**	**Power**	**NOx Removed**
	SCR	Ammonia	0.2-0.5% Plant MW	90%
	Mobotec	None	0.5-0.9% Plant MW	40-50%
	SNCR	Ammonia or Urea	<0.05% Plant MW	20-30%
	Low NOx Burners/OFA	None	Not Applicable	30-50%

Mercury	Technology Selected	Chem. And Waste	Power	Hg Removed
	TOXECON1, 1.5 and 2	3-10 lbs/MMacfm AC Waste=Fly Ash w/ PAC	0.02-0.5% Plant MW	50-90%

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FLUE GAS DESULFURIZATION SYSTEMS

Wet Limestone With Forced Oxidation (LSFO)

Limestone with forced oxidation (LSFO) FGD is a modification of a traditional wet limestone FGD process. This process alleviated former problems such as gypsum scaling and dewatering that plagued early natural oxidation, wet limestone processes. Consequently, the LSFO process has become the preferred wet FGD technology worldwide. LSFO offers the advantage of controlled oxidation of reaction products and potentially scale-free operation of the wet scrubber (scale-free operation has been maintained at many of the latest FGD installations according to published data). Depending on site-specific conditions, LSFO can produce waste solids suitable for landfill, or the system can be designed to produce a salable byproduct in the form of commercial-grade gypsum that can be used for wallboard manufacturing or other industrial applications.

LSFO Process Description and Process Flow Diagram - In the LSFO process, hot flue gas exiting the ESP enters a spray tower where it contacts a dilute calcium carbonate and calcium sulfate slurry (typically 15%-20% by weight suspended solids). The dissolved SO_2 reacts with the calcium carbonate in the limestone particles and the slurry drains into the absorber sump.

LSFO Reagent Feed System - Limestone will be received at the site via truck or rail for treatment of the flue gas. The LSFO system will require the installation of a limestone receiving, transfer, storage and slurry preparation system to support the needs of the new LSFO FGD absorbers.

LSFO SO_2 Removal and Byproduct/Waste Handling - The SO_2 reaction with calcium carbonate initially forms calcium sulfite, which is subsequently oxidized to calcium sulfate (gypsum) in the absorber sump. The formation of gypsum crystals in the slurry helps to reduce scaling potential by providing suspended crystal surface for crystal growth and reducing the calcium sulfate saturation level in the slurry. A certain level of sulfate super-saturation is required for gypsum formation.

The gypsum is typically dewatered using a thickener or hydroclones. For this analysis, hydroclones are used to separate the solids in the scrubber slurry from the liquor fraction. Based on the expected flow rate, the composition and particle size of the byproduct/waste solids stream produced by the scrubber can be calculated. The hydroclone underflow (40-50% solids) flows by gravity to a central collection point and then is pumped to rotary drum vacuum filters capable of handling the final dewatering requirements of the plant. The hydroclone overflow and filtrate from the rotary drum filters are returned to the scrubber reaction tank. For this evaluation, it was assumed that the gypsum is then transported to a landfill for disposal.

The LSFO process requires makeup water to replace the losses that occur through evaporation, water bound in the crystal matrix, and the liquor entrained in the waste solids. This makeup water can be supplied from any source that is not saturated with respect to any of the dissolved solids. Many plants use blowdown from the cooling tower or other wastewater streams produced by the plant as the primary source of LSFO

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FGD makeup. It should be noted that the mist eliminator (ME) wash stream must be higher quality water to maintain scale-free operation. This intermittent wash water stream does serve as a portion of the scrubber makeup water. If poor quality wash water is used for ME wash makeup, or if scrubber liquor is utilized, this typically will lead to heavy scale formation that cannot be removed without taking the unit off-line for manual cleaning.

The chemistry for this process begins with limestone ($CaCO_3$), the absorbing reagent, fed to the open spray tower absorber via the reaction tank. The aqueous slurry of limestone is added at a molar feed rate of 1.03-1.05 moles of $CaCO_3$/mole of SO_2 removed. The major product of the SO_2 reaction with limestone is the formation of hydrated calcium sulfite ($CaSO_3 \bullet 1/2H_2O(s)$) according to the following reaction:

$$CaCO_3(s) + SO_2(g) + 1/2H_2O \rightarrow CaSO_3 \bullet 1/2H_2O(s) + CO_2$$

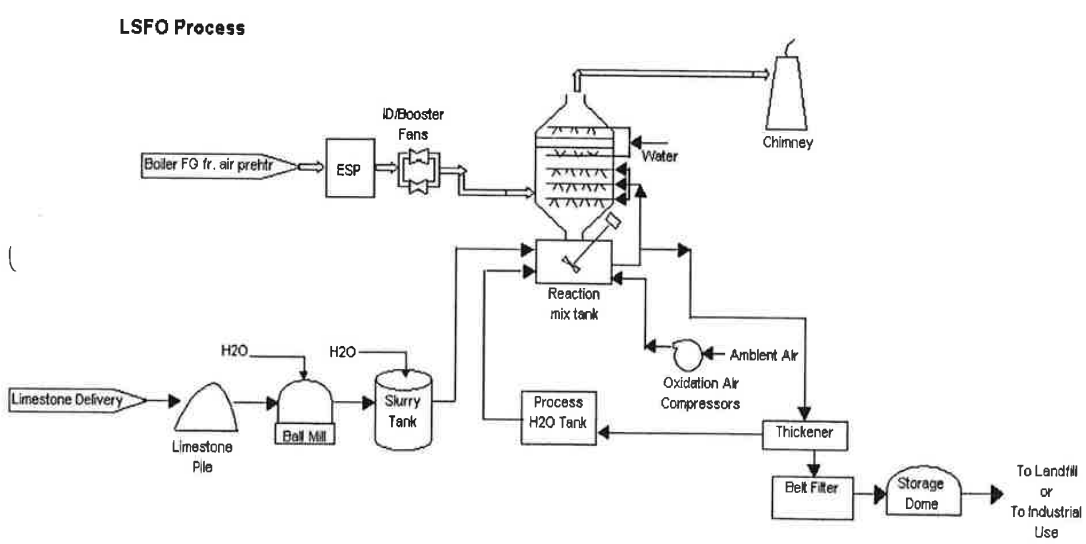
The sulfite is oxidized by the injection of air into the absorber reaction tank, and then hydrated to form calcium sulfate ($CaSO_4 \bullet 2H_2O$) through the following reaction:

$$CaSO_3 \bullet 1/2H_2O(s) + 1/2O_2 + 3/2H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

Figure 3-1 is the process flow diagram for the LSFO system assuming the use of an open spray tower for gas-liquid contact:

<u>LSFO Reagent Required – Waste/By-Product Produced</u> - The LSFO process requires limestone as its reagent, producing a gypsum waste. If landfilled, FGD gypsum is typically designated non-hazardous. High mercury, arsenic, or other toxic heavy metal concentrations in the coal could potentially result in permitting problems for landfill disposal. In any case, Federal guidelines have designated fly ash non-hazardous, but appear to have left FGD solid waste status up to the State regulatory agencies.

Figure 3-1 LSFO Process Flow Diagram



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Gypsum has many potential industrial uses. Wallboard manufacturing is the most common application in the U.S., but gypsum is also used in other plaster products, as a set regulator additive for Portland cement and as a soil conditioner. When used as a soil additive, gypsum can:

- Act as a neutralizing agent for alkaline or saline soil that is reclaimed or irrigated
- Provide sulfur and calcium in the fertilizer mix
- Improve heavy clay soil permeability – peanut-producing regions in the South Atlantic states were mentioned as a major user.

Further refining is required to produce gypsum that is used as a filler in food and other industrial products. Other smaller uses include the brewing industry to promote yeast fermentation, as a substitute for salt cake in glass manufacturing, and as a filler in wood, paints, toothpaste, medical prescriptions, and food products. Other uses that could see future growth include use as a substitute for asbestos, and as reinforcing filler for plastics, and in the production of calcium sulfide and other chemical compounds. Due to the locations of the Entergy coal-fired plants, finding a market for the gypsum solids appears to be unlikely at this time, so landfill disposal has been assumed for this evaluation.

LSFO Removal Capabilities and SO_2 Removal Design Criteria - The LSFO process is capable of removing more than 95% of the SO_2 present in the inlet flue gas. The following table provides the design criteria for this evaluation:

SO_2 Removal	95% - long term average may be lower
Absorber Pressure Drop	6 in. H_2O
Scrubber Modules	1 – 100% for each unit at each site
Scrubber Design	Open Spray Tower
L/G Ratio	125 gpm/1000 saturated acfm
$CaCO_3$ reagent feed ratio	1.05 lb-mole $CaCO_3$ / lb-mole SO_2 removed
Absorber tower superficial velocity	13 fps
Tower gas residence time	10 seconds
Oxygen feed rate	2 lb mole O_2 (from air)/lb mole SO_2 removed
Percent oxidation	100%
Scrubber slurry pH	5.3

LSFO Maintenance Issues - An issue of concern is the maintenance required to keep an FGD system running with as few failures/problems as possible. Compared to the conventional limestone process, LSFO has less labor requirements, reduced equipment pluggage/scaling issues, and the similar equipment maintenance requirements to handle material corrosion and erosion.

LSFO - Use of Dibasic Acid - Adding organic acid (typically dibasic acid/DBA - a mixture of glutaric, adipic and succinic acids, or formic acid, etc.) to a limestone wet FGD system sometimes can increase removal efficiency, reduce the recycle rate (liquid to gas ratio) by 30% or more, reduce operating costs and potentially increase system flexibility to handle a wider range of coal composition. The performance improvement that can be achieved in a retrofit scenario has varied from one site to another. Organic acid addition has been specified for a few recent LSFO system retrofits, but in the past, it

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ETR_00000701

served as a method to recover from performance deficiencies once an FGD system was started up. The addition rate is typically 20 pounds per ton of SO_2 removed.

The organic acids act as a buffer to the dissolution of limestone in the scrubber slurry. By increasing the dissolution rate, they increase the available alkalinity, making more calcium carbonate available for reaction with the sulfite ion produced when the SO_2 dissolves into the scrubbing liquor. The primary mechanism for improving limestone availability is the organic acid removal of excess hydrogen ions from the solution (making it less acidic), and reducing the SO_2 backpressure. This allows the system to operate at a lower pH and lower recycle rates while maintaining the same removal efficiency. The reduction in limestone consumption will not be significant in the current system designs. Most LSFO systems are already operating at stoichiometric feed rates of 1.03-1.05 to maintain gypsum quality, so the potential reductions are only about 0.01 moles/mole of SO_2 removed.

Organic acids degrade in the scrubber due to a carboxylic oxidation that cuts the long chain molecules into smaller more volatile organic compounds. One of these is valeric acid that has a musty odor. This odor is one of the potential problems with DBA use. These degradation products vaporize into the flue gas and exit through the stack. Some of the DBA also ends up in the gypsum, potentially degrading its value as a wallboard feedstock. A gypsum washing process will recover most of the DBA, but some will be occluded in the gypsum crystal matrix and some will coprecipitate with the calcium sulfate crystals. Wallboard manufacturers will typically specify some maximum concentration in their purchase agreement if they know that organic acid use is being considered.

Environmental risk with storage of these organic acids appears to be minimal. Normal containment systems (dike surrounding storage tank) should be sufficient to eliminate any loss to the surrounding environment. The 50% solution that is typically delivered to the site is non-flammable and worker exposure limits are limited to ingestion. Due to the limited impact on the FGD system operation when firing low sulfur coals, DBA was not considered as an option for the Entergy plants.

LSFO Advantages/Disadvantages - The advantages of the LSFO system over a natural oxidation system include the following:

- Increased reliability due to lower scaling potential on tower internal surfaces due to the presence of gypsum seed crystals and reduced calcium sulfate saturation levels in the recycle slurry.
- Better settling and filtering properties of the gypsum product.
- A lower chemical oxygen demand in the final product if sent to landfill.
- The production of stable solids that can be readily and safely landfilled, provided that impurities such as heavy metals are not present in the by-product (if the ESP operating up stream of the FGD system is performing properly, then metals contamination of the FGD waste would not be expected). Liner requirements would be established during the detailed design phase of the project.
- Process modifications can allow the production of wallboard-grade gypsum.
- Limestone dissolution (and therefore utilization) increases in a forced oxidized system due to the oxidation air stripping CO_2 out of the slurry. $CaCO_3$ relative

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saturation decreases as a result, and the driving force for limestone dissolution increases.

- Abundant and low cost sources of raw material are available across the U.S.

Disadvantages would include the increase in carbon dioxide emissions due to its release during the reaction of limestone with sulfur dioxide and the relatively high recycle rate required to obtain high removal efficiencies.

LSFO Purge Water Treatment - Depending upon the sources of makeup water, the coal composition, and the byproduct specifications, it may be necessary to treat a wastewater purge stream from the FGD process. Treatment may be necessary to control the concentrations of dissolved solids in the scrubber liquor as it concentrates due to the continuous recycle of scrubber slurry and water evaporation into the flue gas. Contaminants that may require removal could include trace heavy metals and chlorides. Multi-stage treatment systems are typically used, consisting of precipitation, flocculent, and dewatering equipment to address Hg, F, Cd, and other contaminants. Sodium hydroxide or lime is added to increase the pH to approximately 9 where many metals will tend to precipitate out of the solution. Sodium sulfide is then added to precipitate additional metals to levels of less than 0.1 ppb. Ferric chloride is then added to remove excess sulfides and to produce large flocs of solids that are easily dewatered. Chloride can be removed by a variety of methods including evaporation or treatment with activated carbon. The solids generated by these treatment systems will have to be disposed of in an environmentally acceptable manner. Depending upon the contaminants present, additional treatment steps could include oxidation, neutralization, etc.

LSFO Development/Commercial Status - The initial development of lime/limestone FGD systems sought to obtain scale-free operation by minimizing or eliminating calcium sulfate from the system. However, following the completion of numerous laboratory and pilot tests, it was found that an end product containing a high percentage of calcium sulfate was beneficial. It is easily dewatered and easier to dispose of than sludge high in calcium sulfite.

Initial pilot tests in the U.S. were conducted by Borgwardt at EPA's Research Triangle Park Laboratory, followed by pilot tests at the Shawnee test facility in Kentucky; by Research-Cottrell with Knauf at Martin Lake and Apache stations; and by GEESI at the Monticello Station. Japanese and German companies also completed test programs throughout the 1970's. The Japanese and German research resulted in commercial applications of external and in situ forced oxidation systems, typically producing a wallboard-grade gypsum product.

All vendors who supply wet limestone FGD systems offer a forced oxidation process. These vendors use various absorber designs to accomplish oxidation of the sulfites to sulfates. A partial listing of these vendors is presented below:

- Alstom Environmental
- Babcock and Wilcox
- Chiyoda Corporation/Black & Veatch
- Kawasaki Heavy Industries
- Lurgi Ljentes Bischoff Inc.
- Mitsubishi Heavy Industries/URS/Advatech
- Saarberg-Holter

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ETR_00000703

- Wheelabrator Air Pollution Control
- Hamon Research-Cottrell

The following are brief descriptions of the various limestone scrubbing systems offered by some of these vendors:

Chiyoda Thoroughbred 121 Process – The flue gas, laden with SO_2, is introduced into the Jet Bubbling Reactor where it is scrubbed by the internally recirculating liquid in the jet bubbling layer. Pulverized limestone is also fed into the reactor as a slurry of 20 to 30 wt. % solid. The cleaned gas is freely vented after it disengages from the entrained mist. The solid content in the scrubbing liquid is maintained by drawing off a small portion of the liquid to a centrifuge. In the centrifuge, the slurry is separated into dry gypsum and clarified liquid that is recycled to the absorber for reuse.

Kawasaki Heavy Industries (KHI) Process – Wet limestone scrubber where magnesium hydroxide represents 0.4-0.5% of the lime slurry.

SHU's Formic-Acid, Enhanced, Wet Limestone System – This process employs a two-stage combined cocurrent/countercurrent absorber with formic acid enhancement to maximize inherent advantages of the process chemistry and permit optimization of residence time and liquid/gas ratio.

Mitsubishi Heavy Industries/Advatech – A wet FGD system that uses a double contact flow scrubber (DCFS), which provides gas-slurry contact through the use of large fountains that provide both co- and counter-current contact in an open vessel. Forced oxidation is completed by the injection of air into the reaction tank.

LSFO Mercury Removal - Wet FGD systems ability to capture mercury from flue gas generated by a coal-fired boiler has been a topic of major interest in recent public forums. The removal efficiency varies with fuel characteristics, boiler operating conditions, chloride content, and a wide range of other parameters. The range of removal efficiency stated in recent studies seems to fall between 10-60% depending upon the oxidation state of the mercury in the flue gas (up to 90% of the oxidized species). Unoxidized elemental mercury tends to pass through the scrubber unaffected. Since PRB fired boilers tend to produce primarily elemental mercury, the FGD system Hg capture at the Entergy facilities is expected to be 20% or less.

The removal efficiency of mercury by a wet FGD system can be increased by two different methods:

- Oxidize the mercury before it enters the scrubber
- Add compounds to the scrubber slurry that will keep the oxidized mercury in the solution rather than having it stripped out into the flue gas before it exits the vessel.

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Lime Spray Drying

The lime spray drying process is a semi-dry FGD system that produces a relatively dry mixture of fly ash and reaction products. Issues limiting the use of the LSD system are sites that need to maintain high (greater than 93%) SO_2 removal efficiency, and the fact that no current market exists for the LSD solid waste stream. Landfill disposal will be required and no ash sales will be possible unless the existing particulate control system is left in operation and a new fabric filter or ESP is installed downstream of the LSD absorber vessels. This is an option for the Entergy plants where the existing cold-side ESPs could be left in operation with the new LSD system operating upstream of a new baghouse.

LSD Process Description - In this process the hot flue gas exiting the boiler air heaters enters either the existing ESPs for fly ash removal, or it flows into the new spray dryer vessel (cylindrical, conical bottom, or horizontal box). Within the vessel, an atomized slurry of lime and recycled solids contacts the flue gas stream. The sulfur oxides in the flue gas react with the lime (and any fly ash alkali) to form calcium salts. The water entering with the slurry vaporizes, lowering the gas temperature and raising the moisture content of the scrubbed gas. In some spray dryer designs, the scrubbed gas leaves from the side of the vessel, and a portion of the dried reaction products and ash drop out into the conical bottom of the spray dryer vessel.

The spray dryer outlet temperature is typically controlled within 1-2°F of the operating set point (normally 25-35°F above the gas saturation temperature). If the coal sulfur content varied over a wide range in a short period of time, there might be a tendency to operate outside of the normal outlet temperature range. A closer approach to the saturation temperature would allow the LSD system to achieve higher removal efficiency for a short period, but at the same time risking the buildup of solids on internal surfaces and damage to the bag material in the downstream baghouse.

A particulate control device will be required downstream of the spray dryer. A fabric filter or ESP operating downstream of the LSD vessels will remove the dry solid reaction products, unreacted reagent, and fly ash before the scrubbed gas is released to the atmosphere. The retrofit of a baghouse has been assumed for the evaluations of the Entergy units. In most new installations, a baghouse (FF) would be used as the particulate device downstream of the spray dryer to enhance SO_2 removal efficiency. The FF bags collect a layer of solids on their surfaces between cleanings, and the movement of the flue gas through this layer enhances the gas-solid contact compared to an ESP where the solids collect on the plates and the flue gas only flows past the external surface of the solids. A portion of the collected reaction product and ash solids is recycled to the slurry feed system. The remaining dry solids are transported to a landfill for disposal. To-date, no utility has successfully marketed all of the mixed waste solids generated by a LSD FGD system. Figure 3-2 is the process flow diagram for the LSD system.

The following chemical reactions define how the sulfur dioxide is removed from the flue gas in the lime spray drying process:

- Raw lime is slaked with an excess of water to form a calcium hydroxide slurry:

$$CaO + H_2O \rightarrow Ca(OH)_2$$

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- The sulfur oxides in the flue gas are absorbed into the slurry and react to form the salt products:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \bullet 1/2H_2O + 1/2H_2O$$

$$Ca(OH)_2 + SO_3 + H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

- Any HCl in the flue gas, present because of the chloride content of the fired coal, also absorbs into the slurry and reacts with the slaked lime by:

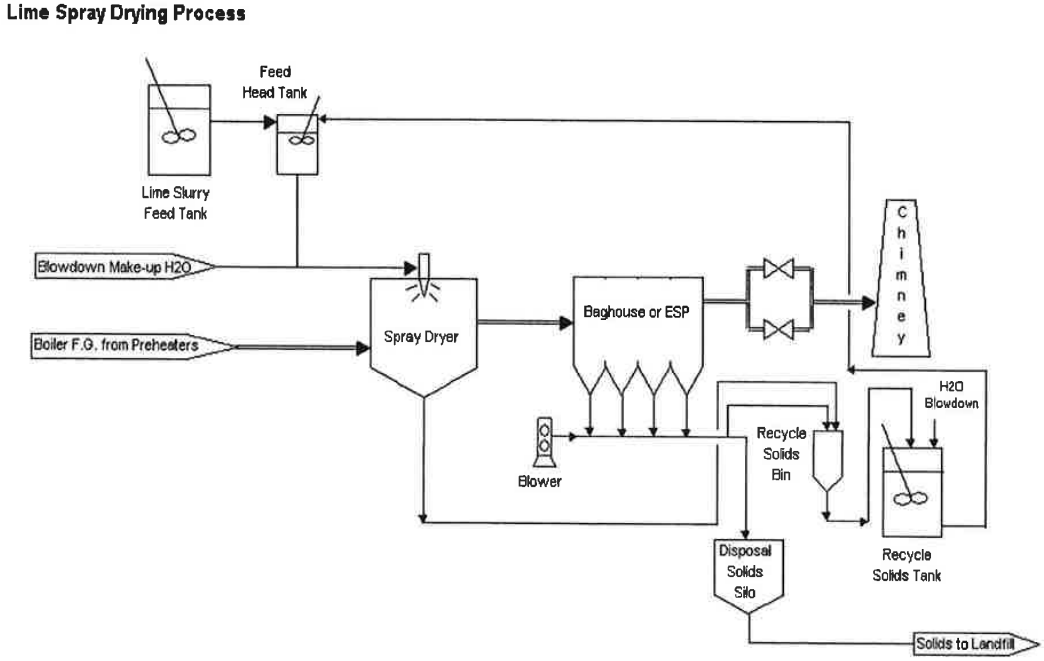
$$Ca(OH)_2 + 2HCl \rightarrow CaCl_2 + 2H_2O$$

  This effect will be less significant for the operation of the Entergy units due to the use of relatively low-chloride subbituminous coals.

- A fraction of the sulfite product may also be oxidized to the sulfate form by reaction with oxygen in the flue gas:

$$Ca(OH)_2 + SO_2 + 1/2O_2 + H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

Figure 3 2. Lime Spray Drying Process Flow Diagram



The majority of the water in the slurry evaporates in the spray dryer vessel, leaving dry particles composed of the reaction products, unreacted absorbent, and fly ash. In the particulate control device, the remaining SO_2 continues to react with the residual lime in the collected solids, although, at a much slower rate. As much as 25% of the total SO_2 removal can occur in a

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baghouse while the SO_2 removal in an ESP is generally lower (5-10%). As a result, lower lime feed rates are possible with spray dryer systems operating upstream of baghouses vs. ESPs.

Most of the sulfur trioxide that is found in coal-fired flue gas is also absorbed in the LSD vessel through direct reaction with hydrated lime. This eliminates the potential for plume opacity due to acid mist, as well as reducing the potential for sulfuric acid corrosion in the downstream ductwork and FF/ESP. However, if the outlet gas temperature drops too low, then water condensation can occur on downstream surfaces. The water droplets can absorb additional SO_2 producing sulfurous acid and increasing the potential for corrosion, especially at cold spots such as round the doors in the FF. Adequate insulation is required and must be maintained.

LSD Reagent Required/Waste/Byproduct Produced - The reagent used in lime spray drying is lime in pebble form. Fresh slaking water is introduced into a ball mill slaker with the dry pebble lime, hydrating the lime and pulverizing the inert material. The slaked lime, $Ca(OH)_2$, flows to an agitated lime slurry feed tank, and this slurry is then pumped to head tanks feeding the rotary atomizers that inject the slurry into the spray dryer vessel.

Waste products of this process include calcium sulfite/sulfate, unused hydrated lime, and fly ash. A portion of the collected reaction products and fly ash solids is recycled to the slurry feed system and the remaining solids are sent to a landfill for disposal.

LSD Removal Capabilities - The following table summarizes the design criteria used in this evaluation:

SO_2 Removal Capability	Up to 95% - average long term performance may be lower
Spray Dryer Pressure Drop	5 in. H_2O
Scrubber Type	Spray Dryer
Scrubber Capacity (maximum capacity per vessel is typically 350 MW)	3 @ 33.3% for Independence and White Bluff REDACTED
Gas Residence Time in Absorber	10 sec
Lime Feed Rate	1.1 moles of CaO/mole SO_2 inlet
Total Dryer Solids Recycle	$\frac{\text{1.4 lb. dry solids recycled}}{\text{lb. lime added}}$
% Solids in Recycle Slurry	35%
Interstitial Water Retained by Solids	2%

The removal efficiency contribution of an ESP downstream of a LSD vessel will typically be half or less (5-10%) than the level achieved by a FF (estimated to be 25% removal across the FF). The FF provides continuous contact of the flue gas as it moves through the filter cake collected on the filter media, while the ESP only provides the external surface of the solids collected on the plates in contact with the flue gas. Achieving similar removal efficiency for an ESP vs. a FF installation would require significantly more lime. The need for a new FF at the Entergy plants (assuming that fly ash sales must be maintained) provides the spray drying system with a significant cost disadvantage versus other FGD technologies.

Increasing chloride concentrations at some sites has enabled the LSD process to reduce lime feed rates while maintaining removal efficiency. The chloride necessary to achieve high removal

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efficiency will depend on the sulfur content of the coal and the efficiency required. Chloride concentration will typically range from slightly under 0.05% by weight to 0.3% chloride by weight in the as-fired coal. However, high chloride content can lead to other operating problems, such as increased corrosion rates in stainless steel components such as the atomizer wheels or baghouse equipment, increased deposition of wet solids on spray dryer vessel walls, and difficulty with solids conveying throughout the system. The vendor specification should address their recommendations regarding the impacts that coal chloride will have on system operation and maintenance.

LSD Maintenance Issues - The spray dryer system produces a dry solid product that can be handled by conventional dry fly ash handling systems, eliminating the dewatering solids equipment and reducing the associated maintenance and operating requirements that are typically associated with wet FGD systems. Operating, laboratory, and maintenance manpower requirements are also significantly reduced due to the reduced complexity. One potential problem area with the spray dryer system is that dry solids conveying systems have, to date, proven to be high maintenance areas. Another concern is with the solids handling system at the bottom of the spray dryer, where in cases where the outlet temperature has dropped too low, it can result in the formation of a cement-like material that drops to the bottom of the spray dryer, requiring the solids handling system to be disassembled and the damp material removed.

LSD Advantages/Disadvantages - The advantages and disadvantages of the lime spray dryer process as compared to the limestone forced oxidation (LSFO) system are as follows:

LSD Advantages

- The spray dryer systems require only a small stream of scrubbing slurry to be pumped into the spray dryer as compared to the large volume of scrubbing slurry recycled in wet systems. This small, alkaline stream contacts the gas entering the dryer rather than the wall of the system. In wet systems, the wall of the absorbers, tanks, and pipes are subject to corrosion because of the continuous contact with low pH slurries. The high pH slurry and dry solids product inherent in the spray dryer allow mild steel materials of construction for the spray dryer vessel and slurry tanks. In contrast, wet FGD systems frequently require liners or higher alloys at various locations in the system.
- Wet systems require thickeners, hydroclones, centrifuges, vacuum filters, and mixers to handle the wet sludge product. Since the spray dryer produces a dry solid product that can be handled by conventional dry fly ash handling systems, the result is elimination of the dewatering solids handling equipment and a reduction in the associated maintenance and operating requirements.
- No wastewater treatment is required.
- The smaller volume of liquid scrubbing medium required in dry systems results in reduced pumping requirements, significantly lowering pump power consumption.
- A flue gas reheat system is usually not required because the gas is not saturated when exiting the absorber. This reduces capital costs and eliminates reheat steam consumption.
- High chloride concentrations in the slurry will typically reduce the SO_2 removal efficiency in wet systems. In the spray dryer process, chloride has been found to enhance SO_2 removal.
- Due to the less complex absorption system, operating, laboratory, and maintenance manpower requirements are significantly reduced for the lime spray dryer process compared to a wet FGD system.

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ETR_00000708

- Cooling tower blowdown can be used for all slurry dilutions after completing the slaking of the lime reagent, with virtually no adverse effects on system performance. In some wet scrubber applications, cooling tower blowdown makeup water can have adverse effects on system SO_2 removal performance, particularly with high-chloride content waters.
- Availability of LSD installations over the last decade is typically greater than 98% after completion of the startup period.
- The LSD process removes most of the SO_3 from the flue gas, eliminating the potential for an acid mist plume exiting the stack.

LSD Disadvantages

- The LSD system must be installed upstream of a particulate collection systems. For the Entergy units that currently sell all of their fly ash, a second particulate collection system may be required downstream of the spray dryer absorbers.
- The lime spray dryer process cannot use cooling tower blowdown water in the lime slaking system, requiring fresh water for this step.
- The overall pressure drop for the spray dryer vessels and the fabric filter will be higher than for a standard open spray tower wet scrubber.
- There could be a problem with the solids handling system at the bottom of the spray dryer if the spray dryer outlet temperature is allowed to drop too low, inadequately drying the solids. Temperature control on a day-to-day basis is accomplished using feed forward and feedback signals from multiple instruments including unit load, SO_2 concentration, flue gas temperatures, etc. Transient operating conditions can cause upsets that would results in temporary loss of control and the potential for wet solids reaching the spray drying vessel outlet nozzle.
- The lime spray drying FGD process requires a higher reagent feed ratio (to achieve the desired removal efficiency) compared to a conventional wet alkali system. In addition, lime is more expensive than limestone. However, higher coal chloride levels, and/or calcium chloride spiking, can significantly reduce reagent consumption by some spray dryer FGD systems. In those cases, the savings in reagent consumption are partially offset by the costs of installing a calcium chloride addition system as well as the cost of the calcium chloride added.
- The LSD FGD system will not produce a marketable byproduct. To-date, no LSD installation has found a market for the solid byproduct generated by the system. Test programs have been completed to form aggregate and cinder blocks from the mixed waste of fly ash and sulfate/sulfite reaction products. Attempts are being made to sell the material to wallboard manufacturers in one western state. Without a market for the material, it will be necessary to dispose of the large volumes of material in a landfill, and ash sales may be terminated.

  In Europe, government regulations require that all FGD solid waste streams be used for production of other products (landfill is not an option). Some of these end use options include: sealing and capping material for hazardous waste landfills, sub-base materials for parking lots, road embankments, fill for reclamation projects, makeup reagent for other FGD systems that produce a gypsum byproduct, further processing to produce anhydrite gypsum (set retarding agent for concrete), sand-lime brick production, cement additive, cellular concrete additive, and as a calcium-sulfur supplement for fertilizers. However, none of these industrial uses currently provide a market in the U.S. at this time. Landfill disposal of the mixed fly ash and reaction products is required at all facilities currently operating in the U.S. based on recent

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ETR_00000709

discussions held at user's group meetings attended by Washington Group staff during the last 1-2 years.

LSD Development/Commercial Status - There are currently about 25 utility spray dryer FGD systems operating in the U.S. The largest, awarded to Joy/Niro (technology now licensed to B & W), is Northern States Power Sherburne 3, an 860 MW unit. All units are installed on utilities firing less than 2% sulfur coal and all use lime as the reagent. One unique exception is the Healy installation where limestone is injected into the furnace and calcined in situ. The solids collected in the fabric filter are then slurried and reinjected into the spray dryer vessel.

The first commercial contract was awarded to Rockwell for the Coyote Plant, which began operating in March 1981. Project start-up dates show that most systems will require approximately three years from contract signing to startup.

There are currently two vendors of utility-scale lime spray dryer systems: Babcock and Wilcox (B&W) and Alstom Power (ABB). Other vendors offer LSD systems, but their experience with large installations is limited.

Mercury Removal by LSD Systems - Mercury capture by a lime spray dryer FGD system will tend to be higher than the removal achieved by a wet scrubbing system. LSD test data indicates that Hg reduction ranges from 10-90% removal of the total mercury (20-30% of elemental mercury and 50-60% of oxidized mercury). The design of the downstream particulate collector has a major influence on the mercury removal efficiency. FFs have demonstrated 40-85% removal efficiencies for elemental mercury in some test programs, along with 25% of the oxidized species. The removal efficiency of the FGD system will vary with fuel characteristics, boiler operating conditions, chloride content, and a wide range of other parameters.

Circulating Fluidized Bed

The following analysis of a circulating fluidized bed (CFB) is based on the Lurgi CFB SO_2 absorption system. The Lurgi CFB is intended for retrofit as well as new plants.

CFB Process Description - A CFB absorber relies on a the ability of the flue gas to suspend particulate matter as it moves vertically upward through a vessel, forming a suspended bed of fine-grained solids. As the gas velocity increases, the classical fluidized bed is maintained as long as the bed of particles retains its top horizontal surface within the reactor. With a further increase in velocity, the fluidized bed will expand until the solids are discharged through the top of the reactor. A portion of entrained solids collected by the downstream particulate collector is recirculated back to the reactor, thus creating the circulating fluidized bed.

In the circulating fluidized bed process, the hot flue gas enters the bottom of a fluidized bed reactor. As the flue gas enters the venturi-shaped entrance to the reactor, it is intimately mixed with the hydrated lime reagent and recycled solids. Water is injected into the reactor to humidify the flue gas and assist in SO_2 removal.

The CFB system requires the operation of a downstream cold-side ESP or FF to complete the removal of fly ash and reaction products. Given that the Entergy plants uses large cold-side

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ETR_00000710

ESPs, any CFB absorber installation could use the existing ESP. But for this evaluation, we have assumed that a new FF will be installed downstream of the CFB reactors. These absorber modules are also limited to approximately 300 MW in size, so the sparing philosophy for the CFB design will require that 3 modules (with associated mechanical collectors) be installed on each of the units at White Bluff and Independence. Two modules would be necessary for REDACTED

When using an ESP, humidification can improve particulate removal performance due to the flue gas conditioning effect (lower gas volume and changes to ash resistivity). A relatively high gas velocity (15 fps compared to conventional wet FGD towers operating at 10-13 fps) is required to fluidize the solids in the reactor 'bed' which promotes SO_2 reaction with the lime solids. The spent solids and fly ash are carried out of the top of the absorber and captured downstream by the retrofitted mechanical dust curtain and the existing ESP. A portion of these combined solids is recycled to the fluid bed absorber. The remaining material is transported to a landfill for disposal. Figure 3-3 shows the flow diagram for this process.

The following summarizes the chemistry of the CFB process:

- The raw lime is first hydrated to form the hydroxide:

$$CaO + H_2O \rightarrow Ca(OH)_2$$

- The flue gas enters the fluid bed absorber and as it flows up through the reactor, it mixes with the hydrated lime reagent to form calcium salt products:

$$2Ca(OH)_2 + 2SO_2 \rightarrow 2CaSO_3 \bullet 1/2H_2O + H_2O$$

$$Ca(OH)_2 + SO_2 + 1/2O_2 + H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

$$Ca(OH)_2 + SO_3 + H_2O \rightarrow CaSO_4 \bullet 2H_2O$$

- The predominant sulfation reaction in the absorber is the one producing hydrated calcium sulfite. As the sorbent particles pass through the system, some of the unreacted lime reacts with the carbon dioxide in the flue gas to form calcium carbonate:

$$Ca(OH)_2 + CO_2 \rightarrow CaCO_3 + H_2O$$

- The final spent sorbent, unreacted reagent, and fly ash are collected downstream by a mechanical curtain installed upstream of the first field of the existing ESP as well as the ESP itself.

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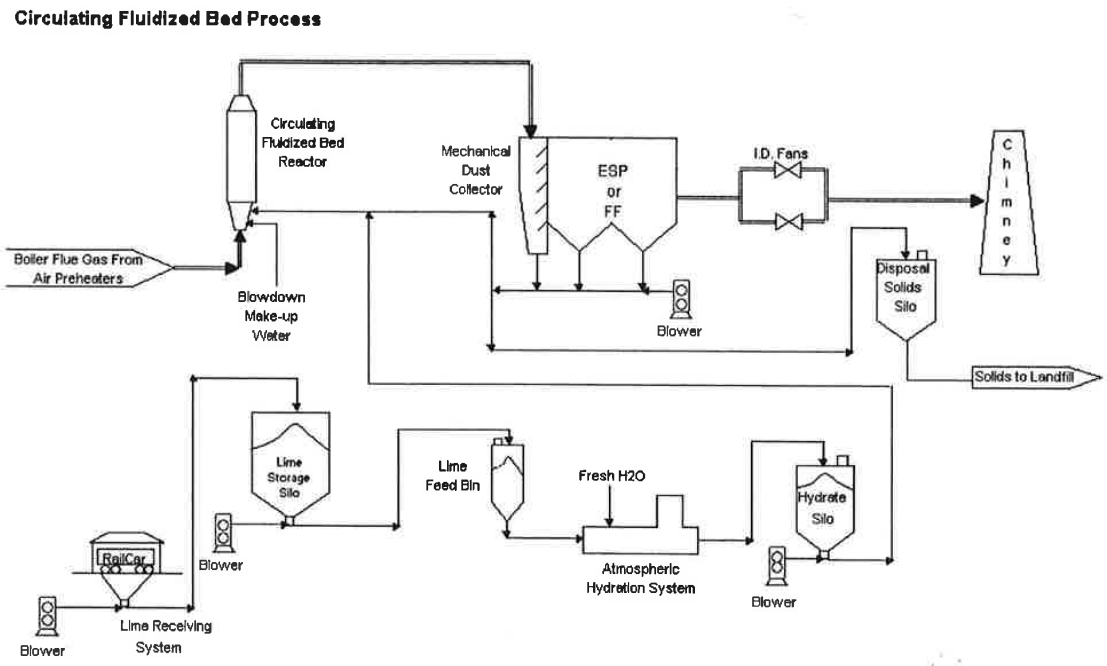
Figure 3-3. Circulating Fluidized Bed Process Flow Diagram



CFB Reagent Required – Waste/By-Product Produced - Lime is the reagent in this process and the dry waste product is composed of spent sorbent/reaction products, unreacted reagent, and fly ash that must be disposed of in a landfill. If the existing ESP is used as the particulate collector, then all fly ash sales would be terminated.

CFB Removal Capabilities - The circulating fluidized bed process can achieve greater than 95% SO_2 removal. The following table summarizes the CFB design criteria used for this analysis:

CFB pressure drop	7.2 in. H_2O
Mechanical collector pressure drop	0.5 in. H_2O
Total system pressure drop	7.7 in. H_2O
Design SO_2 removal	95%
Absorber type	Circulating Fluid Bed
Absorber capacity	2 @ 50% per unit
Gas residence time in absorber	1.5 seconds
Gas velocity in absorber	15 ft/sec
Water injection type	Return-flow nozzle
Mechanical collector type	Angle Iron
Total solids recycled	100 lb solids recycled/lb lime added
Interstitial water retained by solids	Less than 1%

CFB Maintenance Issues - The primary maintenance issue with the CFB process is the potential for semi-dry solids to be present in the flue gas, and subsequent deposition in the downstream

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ETR_00000712

ductwork and particulate collector. Some CFB installations have experienced corrosion of downstream equipment due to problems with water condensation in the particulate collector. The CFB process could have an advantage over other FGD systems in the areas of scale formation in comparison to wet systems and reduced operating and maintenance requirements due to the production of dry solids that can be handled by conventional fly ash systems. Operating and maintenance manpower requirements are also significantly reduced for the CFB process over wet systems due to the elimination of large recycle pumps and dewatering equipment. However, the current designs may require a dedicated fan for each module, resulting in an increase in expected maintenance costs.

CFB Advantages/Disadvantages - The advantages and disadvantages of the circulating fluidized bed process compared to the limestone forced oxidation process are summarized below:

CFB Advantages:

- Lower maintenance costs due to reduced scaling and corrosion when compared to wet FGD systems.
- System will remove most of the SO_3 present in the flue gas.
- Dry solids are produced that can be handled by conventional fly ash systems, resulting in the elimination of the dewatering equipment and a reduction in the associated operating and maintenance requirements.
- Reagent handling is less complex because the hydrated lime is injected in dry form.
- The elimination of slurry handling results in reduced pumping requirements, lowering power consumption.
- Reheat is not required in this system, resulting in reduced capital cost and elimination of reheat steam consumption.
- The O&M manpower requirements are significantly reduced for this system due to the elimination of large recycle pumps and the dewatering equipment.

CFB Disadvantages:

- If the CFB is installed upstream of the existing cold-side ESPs, the fly ash will be contaminated and all ash sales revenue would be lost.
- This process requires a higher reagent feed ratio than do conventional wet alkali systems. In addition, lime is more expensive than limestone.
- Possible duct deposition and plugging problems exist due to flue gas and solids humidification. The pluggage of the CFB absorbers could cause negative pressure transients due to the downstream location of the ID fans.
- A higher solids recycle rate is required relative to other dry technologies.
- Each module may require a separate ID fan.
- The pressure drop for the combination of the CFB vessel and the downstream particulate collector will exceed the pressure drop of a wet scrubber.

CFB Development/Commercial Status - The Lurgi CFB dry process has been in commercial use in Germany since 1987. Lentjes Bischoff GmbH (Germany) now markets the CFB technology from within the Lurgi Group. U.S. installations include the following:

- First commercial application of this technology in the U.S. commenced in August 1995. The Environmental Elements Corporation, under a license agreement with

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ETR_00000713

Lurgi, supplied the Circulating Dry Scrubber (CDS) to the Neil Simpson coal-fired plant in Wyoming (less than 90 MW).

- The Public Service Electric and Gas Company (PSE&G) tested a circulating fluid bed pilot scrubbing unit. The module was installed adjacent to the coal-fired boiler at the PSE&G Mercer Plant in Trenton, NJ.

There are several plants in Germany that currently use this process for SO_2 removal as well. All of these systems were supplied by Lurgi and were retrofit applications.

Two other technologies very similar to the Lurgi CFB process have been developed. These processes are summarized below:

1. WULFF Dry FGD Process – This dry-type flue gas scrubbing process incorporates a Reflux Circulating Fluid Bed (RCFB) as the desulfurizing absorber and a fabric filter or an ESP for separating the solids. An ID fan serves to overcome the pressure drop across the FGD system and to deliver the clean gas to the stack. This process also claims removal of Hg, Hydrogen Fluoride, SO_3, NO_X, and dust.

2. Gas Suspension Absorption (GSA) – In this system, flue gas from the boiler air preheater enters the CFB reactor at the bottom where it mixes with the suspended solids, wetted by fresh lime slurry. Lime particles in the slurry react and bind with the acid components of the flue gas, SO_2 and HCl. FLSmidth has installed more than 40 of these units around the world in both industrial and utility applications using a maximum absorber capacity of 125 MW equivalent gas flow.

NOx CONTROL OPTIONS

Selective Catalytic Reduction (SCR)

SCR Process Description - SCR catalyst is supported in vessels that could be located between the boilers and the existing ESPs. Based on relatively remote location of the Entergy plants, it has been assumed that they would be able to permit the use of anhydrous ammonia to supply the SCR system on their coal-fired unit. This will result in reduced costs for on-site storage and feed equipment, as well as lower operating costs than would be seen for plants that needed to use either aqueous ammonia or urea feed materials to supply the demand of the SCR.

Flue gas will enter the top of the SCR vessel and move downward through the catalyst layers (three operating with space provided for the installation of a fourth layer if required in the future). Since the SCRs would be operating dirty (no upstream particulate removal) they need to be designed to resist the impact of metals poisoning of the catalyst that is typically a significant problem for PRB coal fired boilers. The plugging potential due to popcorn ash formation (again, typical of PRB coals) will also exist, along with the potential for calcium poisoning. PRB coals tend to have high concentrations of alkaline earth metals, including calcium. One catalyst vendor indicated that the calcium can be concentrated in the fly ash fines, and that a low inlet grain loading will not fully protect the SCR catalyst from the effects of calcium poisoning.

Ammonia would be injected upstream of the SCR vessel at a rate equivalent to approximately 0.9-1.0 moles of NH_3 per mole of inlet NO. It then reacts directly with the nitrogen oxide present in the flue gas, reducing it to molecular nitrogen and water. Typical removal efficiencies that can

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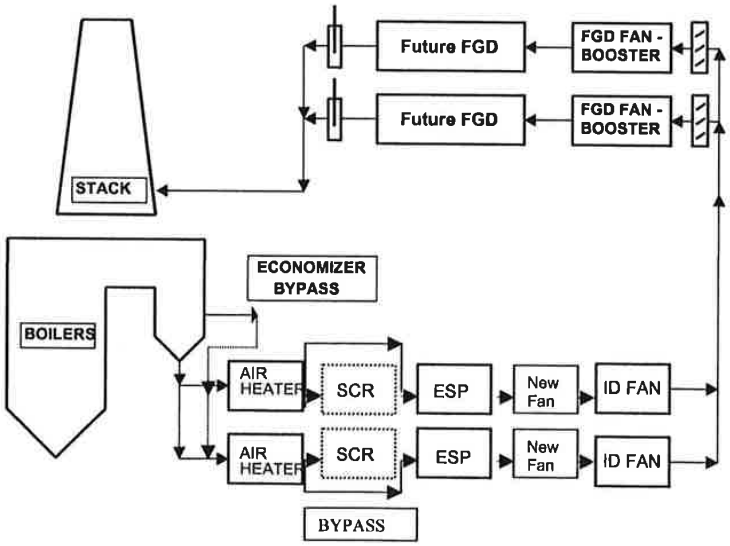
ETR_00000714

be achieved across an SCR are in the range of 80-90% of the inlet NOx. Industry operating experience has shown that utility SCR systems typically achieve average control efficiencies that are 2-5% lower than their design performance during long term operation. SCR system availability has also been reduced by a similar amount for these installations. Designing for higher efficiency (90%) will typically require higher ammonia slip rates, which are undesirable due to equipment fouling (air heater ammonium bisulfite buildup) and the need to reduce ammonia emissions from the stack.

The anhydrous ammonia feed system is relatively straightforward, with feed rates established based on inlet NOx concentrations from a continuous emissions monitor (CEM) and unit load, with trim levels established by measurements of outlet NOx concentrations. Operating guarantees for SCR systems typically include % NOx removal, the ammonia slip concentration, pressure drop and the SO_2 to SO_3 oxidation rate that will occur across the SCR. Figure 3-4 provides a gas path for the SCR conceptual design.

It should be noted that the SCR conceptual design could include the installation of an economizer bypass system. The outlet temperatures of the air heaters at reduced loads could fall below the SCR required gas temperature of 650°F. The Entergy datasheets indicate that at MCR, the gas temperatures at the economizer outlets on each unit are designed to be at least 800°F. An economizer bypass would allow hot flue gas extracted upstream of the boiler economizer to mix with the gas entering the SCRs, providing sufficient reheat to maintain the proper operating temperature for the SCR catalyst. At lower temperatures, the NOx reduction reactions will slow down to the point that unused ammonia will exit the reactor vessel, and NOx levels will increase. The lower temperatures also allow the formation of ammonium bisulfite compounds that can coat the surface of the catalyst.

Figure 3-4. Gas Path for SCR Retrofit



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ETR_00000715

The economizer bypass will require the installation of two additional hot dampers that are used for isolation and to ensure operation of the bypass. It should be noted that the use of an economizer bypass would have some impact on the unit heat rate when it is used. However, some of this energy will be recovered in the air heater, and the economizer bypass will only be required when the unit load drops below 50%. Since the units are typically base loaded and their operating time at reduced load is relatively short on an annual basis (85% capacity factor), the cost impacts of the heat rate reduction were not included in this analysis.

The chemical reactions occurring over the SCR catalyst can be summarized by the reactions stated below:

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

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

No secondary pollutants are produced during these reactions. The only potential toxic compound that is released from this system would be ammonia slip past the reactor. This is typically minimized when the SCR is operating at normal conditions, maintaining slip rates of 2-3 ppm at the outlet of the SCR.

SCR systems are generally designed for a maximum inlet gas temperature of 750°F. This operating temperature is below the material property limits of carbon steel, however, and it may be lower than the maximum economizer-exit gas temperature of some units. In addition to this design temperature, other key process temperatures include:

- All units will use heated ambient air for ammonia dilution. Design temperature range will be from 350°F to 400°F.
- For typical installations, the minimum acceptable flue gas temperature to maintain catalyst performance and eliminate problems with ammonia injection is approximately 610°F.

The addition of the SCR will increase the gas-side operating pressure drop. For balanced draft units, the static pressure in the duct at the air heater (gas-side) and ID fan inlet will be more negative than under previous operating conditions. Gas-path pressure changes, including upset or excursion events due to addition of the SCR and the increase in I.D. fan head capability, are determined by evaluation of the current operating pressure, the design pressure, and a suitable margin below design pressure. Any new or modified flue gas system components will be designed to current guidelines of NFPA 85. More detailed analysis will need to be made during the design phase to determine whether structural reinforcement is necessary.

<u>SCR Reagent Required – Waste/By-Product Produced</u> - Ammonia is the reagent in this process and the waste product is spent catalyst. There will also be a low concentration of ammonia in the flue gas exiting the stack. As was previously mentioned, ammonia can be supplied to the SCR from a variety of sources. Anhydrous ammonia is close to 100% NH_3 and is typically the least expensive source. The liquid ammonia is delivered to the site and stored in pressurized tanks. Pumps move the anhydrous ammonia from storage to the vaporization skid, where it is converted to a gas, diluted with hot air, and blown into the duct through the injection grid.

At sites located in populated areas, it is sometimes difficult to permit the anhydrous ammonia storage tanks. In those cases, aqueous ammonia can be considered, transported to the site as aqueous solutions with concentrations of 29.4% or 19% NH_3. This source of supply is inherently

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ETR_00000716

more expensive than anhydrous because of the large quantities of water that must be transported to the site and then evaporated. Dry urea can also be used as the source of ammonia, producing ammonia by thermal decomposition of urea. This reduces the inventory of hazardous ammonia that will be present at the site, minimizing the permitting issues associated with the ammonia feed system. However, due to the need for the decomposition equipment and the relatively high cost for the urea feedstock, this is typically the highest cost alternative for ammonia supply. For this analysis, we have assumed the use of anhydrous ammonia at all the Entergy plants.

SCR Performance - The SCR process can achieve 80-90% NOx reduction in coal-fired flue gas applications. The following table summarizes the design criteria for this evaluation:

SCR pressure drop	8 in. H_2O
NOx removal	90% - long term average performance may be lower
Vessel type	Carbon Steel with 4 catalyst levels
Reactor capacity	2 @ 50% per unit
SCR gas residence time	1.5 seconds in reactor vessel
Gas velocity in absorber	15 ft/sec
NH_3 injection	Dual fluid nozzles on injection grid piping
Ammonia supply	Anhydrous
Ammonia feed rate	1.0 moles NH_3/mole NOx inlet (assume that NOx = 90% NO + 10% NO_2)
Ammonia slip	<2 ppm

SCR Maintenance Issues - The SCR process has maintenance issues that must be considered in the final design. The main concerns are ash deposition, plugging problems and catalyst poisoning due to flue gas contaminants. Catalyst selection for a specific application is critical to the success of any SCR installation. Catalysts must meet a variety of criteria:

- Resistance to poisoning agents in the coal-fired flue gas
- Resistance to abrasion
- Mechanical strength against soot blowing
- Resistance to thermal cycling
- Low oxidation rates for SO_2 to SO_3 (again, for these low sulfur coal-fired plants, the oxidation rate is less critical)
- Resistance to physical plugging of the gas path through the catalyst.

Catalyst life is finite, typically guaranteed to last 3-4 years, with actual operating life depending upon the gas characteristics and plant operation. Once depleted, the catalyst is usually extracted from the reactor and either returned to the vendor for regeneration or disposed of as a hazardous waste due to the vanadium and other heavy metals content The operating manpower required to support the SCR installation is typically very low. The units tend to operate with only oversight by the control room staff.

SCR Advantages/Disadvantages – The following summarize the advantages/disadvantages of an SCR system compared to alternate NOx control technologies:

SCR Advantages

- Limited manpower needed for operation.
- High removal efficiency for NOx.

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ETR_00000717

SCR Disadvantages

- High capital cost.
- Depends on the inlet gas temperature to be within a certain range to maintain high performance – results in some limitations with regard to load swings and the potential need for an economizer bypass to allow hot gas from the boiler to bypass the economizer and mix with flue gas entering the SCR. This might also be resolved by shutting off the ammonia to allow low-load operation or base the SCR system operation on a total tons of NOx removed per year vs. a NOx removal efficiency depending on what the future regulations allow. The current system is designed for command and control operation, i.e., the SCR must be available for operation or the unit is shut down.
- Adds to the pressure drop of the system
- Can result in high ammonia slip and air heater pluggage if the ammonia feed system does not properly respond to changes in boiler operation.
- Requires the feed of a toxic material – ammonia.

SCR Development/Commercial Status - SCR technology has been installed at numerous sites in the U.S. and hundreds of others around the world. Recent installations on PRB-fired utility boilers have demonstrated SCR performance in low sulfur coal applications. There are more that five vendors currently offering SCR systems in the U.S. and many catalyst suppliers currently serving this market. The large number of installations in Europe and Japan in the 1980s provided the vendors with many opportunities to improve their designs and reduce the learning curve for U.S. utility boiler installations.

SCR Subsystem Description - Each SCR reactor housing will support the catalyst modules on guide frames. The reactor assembly generally includes a catalyst removal system. A monorail system is used to move the catalyst into and out of the reactor housing. The joints between modules are sealed to prevent flue gas bypassing the catalyst.

The following subsystems would be common for all units operating at a single site:

- Anhydrous Ammonia Delivery and Storage
- Containment/Catchment Basins (for accidental ammonia release)
- Ammonia Transfer and Vaporization (pumps and piping that transport ammonia to the ductwork on inlet side of SCR reactor)
- Dilution air supply and heating
- Soot blowers
- Steam supply and condensate return (for ammonia vaporizer)

Source of Ammonia - Alternatives for the source of ammonia would include the use of anhydrous ammonia (simplest and least expensive), aqueous ammonia or the on-site generation of ammonia as needed. The last two options would result in higher capital and operating costs for the Entergy plants. The on-site production process is described below for reference:

On-Site Ammonia Production - One alternative to the storage and handling of large volumes of anhydrous ammonia on the utility site is the use of a urea-to-ammonia conversion system. These systems are designed to supply continuous ammonia feed that can be varied with changes in load and NOx concentration. At least two suppliers are currently offering these systems commercially: Environmental Elements and

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ETR_00000718

Hamon/Wahlco. The Environmental Elements system was installed at a Southern Company plant in the U.S. This technology relies on a recycle stream that is stripped with live steam to produce the ammonia feed. The patent on this process appears to overlap with the system offered by the Hamon/Wahlco, called the U2A process.

In the U2A system, the urea is shipped to the site as a solid and dissolved in a salt storage tank. The urea sits on a bed of gravel and deionized water is sprayed onto the urea to form a saturated solution that is withdrawn from the bottom of the tank. This stream is heated to 125°C with steam and maintained in a reboiler at a pressure of 80 psig. The urea decomposes forming a gas stream that is 28% ammonia, 17% carbon dioxide and 55% water vapor. A 300-500lbs/hour feed system would require a 12' diameter dissolution tank and a 10' x 15' skid surrounded by a containment dike. The reactor/reboiler will contain a 3% aqueous solution of ammonia during normal operation. This results in approximately 100 pounds of ammonia being stored on the site at any point in time. Process gas or air can act as the carrier gas to the NOx control system. Every pound of ammonia produced will require approximately 4500 Btu of 250-500 psi steam.

The U2A process developer previously tried using vanadium and molybdenum catalysts to promote the decomposition of the urea, but simply operating at a higher temperature gave the same results. Testing to-date indicates that no unusual species are formed in the reactor. The estimated capital cost for the U2A process was stated to range from $1000-$1500/pound of ammonia per hour, uninstalled. The cost per pound for a commercial sized U2A system was previously estimated to be $0.21/lb of NH_3 versus an anhydrous ammonia cost of $0.14/lb. The U2A system operates with a closed water balance.

Ammonia Injection System - Each ammonia injection grid is designed for even ammonia distribution throughout the flue gas stream with the capability to manually bias the ammonia injection to account for non-uniformity of NO_x and flue gas flow. Typically, ammonia is diluted with heated air and injected into the flue gas upstream of the SCR catalyst. In the D.B.Riley design, the injection system uses a series of "delta wing" mixing foils with 6 to 8 large diameter nozzles (approximately 5" diameter). A computer flow distribution model controls ammonia injection into the mixing zone, producing an accurate flow distribution without the use of a large number of small diameter nozzles that can be prone to pluggage and flow imbalance.

Ammonia Atomization - Compressed air or steam is used to atomize the ammonia. Dedicated skid mounted compressors are typically used for ammonia atomization.

Dilution Air Fans and Heaters - Two 100% capacity dilution air fans are typically provided for each SCR vaporization skid. The fans are usually centrifugal, skid-mounted assemblies. Steam is typically used to heat the dilution air to 350° to 400°F.

Flow Distribution - Flow distribution devices, if necessary, may be required to ensure adequate flue gas and ammonia distribution and effective utilization of catalyst. The flow at the economizer exit is expected to be stratified and is likely to vary with load. Static and dynamic means of flow compensation may be required.

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ETR_00000719

Electrical Supply - A common electrical supply system provides power to the ammonia pumps, dilution air fans, soot blowers and controls. New electrical components will typically be necessary, including an MCC and new switchgear. Alarm/monitoring signals are wired to the nearest continuously manned control room. The increased pressure drop may require that the existing ID fans be upgraded on some units or new booster fans installed, requiring new electrical connections for larger motors in some cases.

SCR Bypass – Bypass and isolation dampers are often provided for startup and maintenance, which when permitted, can extend catalyst life and reduce the ID fan power consumption.

Mobotec

The following provides a technical description of the Mobotec technology based on data reported in previous publications and recent contacts with the process supplier. This technology has been compared to generic SNCR processes, but it is designed to overcome some of the limitations of that technology and is considered separately in this analysis.

Mobotec Process Description - Mobotec relies on two primary mechanisms for NOx reduction:

- Rotating Opposed Fire Air (ROFA) – This system is designed to improve combustion in the boiler. The gas volume in the furnace is set in rotation by asymmetrically placed air nozzles. Turbulent mixing improves the temperature and species distributions and improves particle burnout in the upper furnace. The particle residence time increases and fuel and oxygen distribution helps to reduce CO and NOx formation. The ROFA system has demonstrated the ability to remove 45-55% of the NOx on both small and large coal-fired boilers.
- Rotamix – This subsystem uses a second-generation selective non-catalytic reduction (SNCR) process. When combined with ROFA, the increased turbulence produces a more homogeneous temperature distribution and mixing of the injected chemical species with the targeted pollutants. This helps to reduce both the chemical feed rates and the slippage of unreacted compounds. The Rotamix system is currently being updated by Mobotec to optimize its performance in coal-fired boiler applications.

  Current projections by the supplier are that the Rotamix system will reduce the NOx levels by an additional 20-30% after process optimization is completed. Test results at their 570 MW installation were not consistent with these projections. Mobotec indicated that they are continuing to test system configurations in their research facility to confirm design parameters for large boiler applications. Final tuning of the Rotamix installation at the 570 MW unit was not completed due to financial and technical issues at that plant.

The Mobotec chemical reactions occurring in the boiler with ammonia injection are summarized by the reactions stated below:

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

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

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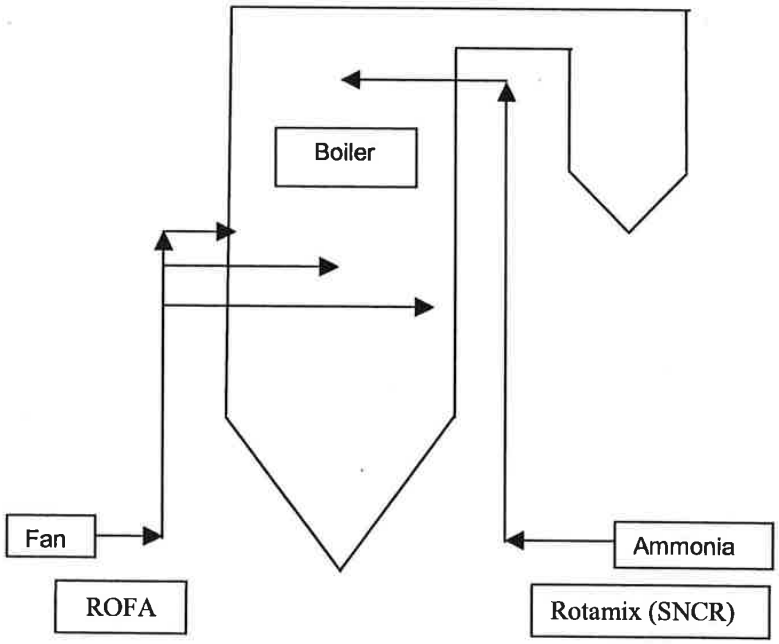
No secondary pollutants are produced during these reactions. The only potential toxic compound that is released from this system would be ammonia slip past the reaction zone in the boiler. This is typically minimized when the Mobotec equipment is operating at normal conditions, maintaining slip rates of approximately 5 ppm at the stack outlet. Ammonia slip can be reduced by the addition of a polishing catalyst layer at the economizer outlet according to the supplier. If urea is used as the source of ammonia to the boiler, then a small amount of carbon dioxide would also be added to the flue gas. Figure 3-5 is a flow diagram for the Mobotec system.

Mobotec has also demonstrated the multi-pollutant reduction capabilities of the system using sodium (trona) and calcium (limestone) additives to the back pass of the boiler. These additives can promote the removal of SOx, HCl and Hg from the flue gas at efficiencies 60-90%. However, these variations on the Mobotec design have not been fully tested in full-scale utility installations.

Figure 3-5. Mobotec Flow Diagram



Mobotec Reagent Required – Waste/By-Product Produced - Ammonia or urea (decomposes to form ammonia and carbon dioxide) are the reagent options for this process. The waste products consist of nitrogen and water vapor, along with low concentrations of ammonia slip in the flue gas exiting the stack. As was previously mentioned, ammonia can be supplied to the Mobotec system from a variety of sources. Anhydrous ammonia is close to 100% NH_3 and is typically the least expensive source. The liquid ammonia is delivered to the site and stored in pressurized tanks. Pumps move the anhydrous ammonia from storage to the vaporization skid, where it is converted to a gas and blown into the boiler through injection lances and nozzles.

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ETR_00000721

Mobotec Performance - The vendor projects that the Mobotec process (combination of ROFA and Rotamix) will achieve 70-80% NOx reduction in coal-fired boiler applications. These efficiencies have been demonstrated on small boilers (less than 200 MW), but on their one larger unit, removal capability was limited to 45-55% using ROFA alone. The Rotamix system did not perform as expected, due in part to the higher temperatures found in the boiler under certain operating conditions, resulting in the need for potential relocation of the urea injection lances. However, the installation at this unit was not optimized due to issues with the utility client, and Mobotec is revisiting the design conditions for large boiler installations of Rotamix.

Given the fact that the Entergy units are larger than any unit where Mobotec has successfully installed and operated the Rotamix system, it has been assumed that the Mobotec equipment will be limited to the ROFA equipment installation (50% NOx removal efficiency). Three to five years from now, Mobotec may have sufficient operating experience on larger units with the Rotamix technology, and at that time, this system might be considered capable of achieving the higher removal efficiencies that are currently projected by the supplier.

The following table summarizes the Mobotec design criteria for this evaluation:

Mobotec Pressure Drop	Negligible
NOx Removal with ROFA Only	50%
Air Feed Extraction Point	Secondary air to boiler
Air Injection Pressures	25" for small units and 50-60" for large units
Impact of Air Heater	Minimal especially in low sulfur coal unit

Mobotec Maintenance Issues - The Mobotec process relies on turbulence generated in the boiler cavity by active air injection. The primary maintenance issues would be those associated with the new air fans, and where Rotamix is used, ammonia interaction with SOx can form ammonium bisulfite that can coat gas path surfaces and the air heater baskets at reduced gas temperatures. The existing control room staff typically operates the Mobotec systems.

Mobotec Advantages/Disadvantages - The advantages and disadvantages of the Mobotec process are summarized below:

Mobotec Advantages

- Vendor projects capital cost to be 70% less than SCR.
- Less dependent upon gas temperature to maintain acceptable performance, at least for the ROFA subsystem operation.
- Limited extra manpower needed for operation.
- Moderate removal efficiency for NOx (45-55% with ROFA and up to 70-80% when Rotamix is added).
- Minimal increase in pressure drop.

Mobotec Disadvantages

- Can result in higher ammonia slip than an SCR installation.
- Removal efficiency may be limited to 70%. One recent installation has reported a NOx reduction efficiency of only half of this design value. Further design modifications are currently underway to improve the efficiency of the Rotamix section of the process.

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000722

- Needs installation of ROFA air fans that have large motors when retrofit on large boilers (175 MW unit required 2-700 HP fans – this would scale to 2-4000 HP fans for each of the units at Independence or White Bluff). Foundations for fans this size are very large, and may need to be installed outside of the boiler house to preclude disturbing the operating unit. If outdoor fans are required, then this will require lengthy duct runs. This would be large ductwork since the system requires the diversion of about 30% of the secondary air to the ROFA air injection ports.
- Requires source of ammonia for Rotamix subsystem if used.
- Multiple penetrations required into the furnace for installation of ROFA ports and Rotamix lances.
- The high injection pressure for the ROFA injection ports raises a concern for potential erosion within the boiler. The air velocity at the injection port is estimated to be about 500 feet per second. The ROFA air induces a rotational flow in the upper furnace. This could force ash particles outward to the boiler walls, as in a cyclone, and may have the potential to increase the rate of erosion of the water wall tubing.
- Other process issues include ammonia storage, air injection locations, carbon monoxide formation, impact on boiler firing patterns and unit turndown, impacts on ESP performance, impact on unit heat rate, furnace operating conditions (temperatures, heat absorption/transfer, boiler geometry, tube wall modifications, etc.).

Mobotec Development/Commercial Status - Mobotec technology has been installed at 20+ sites around the world, including five coal-fired boiler applications in the U.S., the largest a 570 MW supercritical unit. It should be noted that Mobotec systems have only been operated on U.S. coal-fired boilers since 2000, and the large boiler installation was started up in 2003. Therefore, even though there have been multiple installations on boilers in the U.S. and Europe, the operating history for these systems is very limited, and long-term performance and maintenance data is not available, specifically in the areas related to impacts on the boiler components such as tube erosion, etc. Descriptions of some of these installations are provided below:

Mobotec Experience Summary - Pulverized Coal Fired Units

- Site visits:
  - Washington Group staff visited Mobotec's ROFA/Rotamix installation at Progress Energy's (Carolina Power & Light) Cape Fear Station - 154 and 172 MW units.
  - Other Washington Group International personnel visited Dominion Power's Yorktown Station's 175 MW unit (a second 175 MW unit Mobotec retrofit is currently being started up); and a confidential client's opposed wall-fired 570 MW eastern US unit.
  - Both Progress Energy and Dominion are pleased with the Mobotec ROFA/Rotamix installations.
- In service dates and performance:

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000723

- Cape Fear Unit 5 - Started up summer 2000 with ROFA and achieved 55% NOx removal at full load. Rotamix was added in 2002 and in combination with ROFA achieved 73% and 84% NOx removal with ammonia and urea, respectively.
- Cape Fear Unit 6 - Started up summer 2002 and achieved 55% NOx removal with ROFA only, and ROFA and Rotamix combined achieved 71% and 79% removal with ammonia and urea, respectively.
- Yorktown Unit 2 - Started up summer 2002 and achieved and achieved 59% NOx removal with ROFA only, and ROFA and Rotamix combined achieved 63% and 77% removal with ammonia and urea, respectively.
- Target performance for the Cape Fear and Yorktown ROFA/Rotamix system was 64%.

- Large 570 MW unit experience:
  - This unit has operated with ROFA and Rotamix for one ozone season (summer 2003).
  - ROFA achieved about 55% NOx reduction at full load per Mobotec and met the predicted reduction. Client's opinion is that this level was only achieved for short durations and that average full load reduction level is less than this (about 40-45%). Note: Plant CEMS NOx measurement is from a common stack partially shared with an adjacent unit, so accurate performance measurement was impossible.
  - Closing of close-coupled NOx ports (formerly upper cell burners) was not possible due to overheating concerns. Mobotec's initial ROFA design reportedly was based on closing these NOx ports.
  - LOI improved. Possible change in CO emissions was not accurately documented.
  - Rotamix performance dropped off above 80% load due to high gas temperatures. Client's opinion is that Rotamix did not work. Modifications to relocate Rotamix injection ports and tuning work were not completed due to client's serious financial problems that were present throughout this project.
  - Boiler system reported to have significant combustion system imbalances. This was a preexisting condition.
- Mobotec contracts with Reaction Engineering to perform system CFD modeling, which to date has been successfully utilized to predict Mobotec system performance.
- System tuning:

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ETR_00000724

- ROFA system tuning primarily consists of varying the air pressure to different ROFA injection boxes, and if required, changing air nozzle/orifice sizing and the direction of air injection.
- Rotamix system tuning consists of varying the nozzle locations used for ammonia or urea injection, and changing injection rate.

- Baseline testing is important for proper design of Mobotec equipment.
- Assessment of Mobotec's technology:
  - Rotating overfire air (ROFA) has performed well and has achieved NOx reduction levels predicted by Mobotec on small and medium sized 25-200 MW units. Mixed results have been obtained at Mobotec's one large unit retrofit to date.
  - Ammonia/urea injection in combination with ROFA (Rotamix) is still a developing technology. Consequently, Mobotec's NOx reduction predictions for a ROFA/Rotamix system should be discounted to 50% at this point in time. Mobotec has stated that they are continuing their research to determine why their initial predictions were not consistently achieved. Use of a urea solution in water with the Rotamix system has demonstrated higher NOx removal compared to the use of aqueous ammonia.
  - Mobotec has not been demonstrated on coal-fired boilers as large as the units operating at any of the Entergy plants.

Low NOx Burners With Advanced Over-Fire Air

The following section provides a technical description of the Low NOx Burner with Over-fire Air technology based on data reported in previous publications and recent submittals from the equipment supplier.

Low NOx Burners (LNB) Description - LNBs are designed to control fuel and air mixing at each burner in order to create larger and more branched flame patterns. This reduces the peak flame temperature and results in lower thermal NOx production. The modified flame structure also reduces the amount of oxygen available in the hottest part of the flame, improving burner efficiency. Primary combustion, NOx reduction, and fuel burnout are accomplished in three stages in a LNB:

- The first stage of combustion occurs in a fuel rich zone where oxygen levels are maintained below the requirement for complete combustion. Most NOx species are formed in this zone.
- The second stage is a reducing zone where unburned hydrocarbon species act to reduce the NOx that was formed in the first stage.
- The third provides internal air staging, which completes the combustion of the available hydrocarbons, but also produces additional NOx during the burnout process. Completing the combustion process in an air-lean environment can minimize the NOx production rate.

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Advanced LNB designs incorporate other design modifications into the burner. These can include distribution of coal particles and internal recirculation zones within the burner, producing internal air and fuel staging within the flame. Impellers, adjustable spin vanes, separate coal nozzles, and multiple air nozzles have also been used in some burner designs. In some cases these additional design features minimize the carbon content in the fly ash and reduce carbon monoxide content in the flue gas. Venturi nozzles and coal spreaders have also been used to produce a slower mixing, less turbulent flame.

LNB retrofits at large utility boilers have reported NOx reductions of 30-50% in some cases, with retrofit costs reported to be approximately $10 to $30/kW depending on boiler size and degree of retrofit difficulty. Many of these projects were implemented without significant reductions in boiler performance or major increases in carbon monoxide emissions or fly ash carbon content.

LNB installations have been combined with other NOx control technologies to obtain higher levels of NOx reduction. The potential performance of these combinations of technologies is described in more detail later in this section.

Air Staging/Overfire Air Description - Air staging divides the combustion zone into two separate areas. It typically involves the introduction of overfire air into the boiler. Air staging can also be accomplished in low NOx burners (internal air staging). For furnace overfire air, the combustion air is divided into two streams. 70 to 90% of the combustion air (primary air) is mixed with the fuel and injected into the furnace through the burners. The lower oxygen concentration helps to minimize flame temperatures, which makes the flame fuel-rich/oxygen deficient (producing only moderate amounts of NOx). The remainder of the combustion air is typically injected above the primary combustion zone using a separate windbox with air injection ports positioned 5-10 feet above the top row of burners. The flame volume is increased in the secondary combustion zone, which results in reduced flame temperatures. The secondary "reburn" zone is air rich, typically having a fuel to air stoichiometry of 0.8 to 0.9. The port locations are critical to the success of the overfire air system, and is unit specific depending on flame profiles, etc.

Air staging typically requires installation of air injection ports through the existing boiler tube wall, ductwork, dampers, windbox, and modifications to the existing control system. This technology has been applied at more than 300 coal-fired units around the world as a stand-alone technology or in combination with other NOx control equipment.

Variations on the overfire air system have been given other names based on the location of the ports in relation to the burners: close-coupled overfire air and separated overfire air. This technology has been applied to both wall- and tangentially-fired boilers. NOx reduction varies widely depending on furnace characteristics and whether other control technologies are operating. Some tangentially fired units have reached 0.15 lbs/MMBtu while keeping the unburned carbon to less than 5% and the CO levels below 50 ppm.

Plant Impacts – LNBs have been under development over the last 30 years. Many of the technical issues have been resolved during this extended period of development; some of primary design considerations are discussed in the following material. Installation of LNBs and staged combustion, termed overfire air, will help to reduce the NOx emission rate for most boilers. However, the furnace provides a complex environment, and the specific levels of control efficiency will vary from one unit to the next. Predictions of performance are typically based on

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ETR_00000726

empirical data derived from installations on similar boiler designs. Some of the typical impacts on the existing boiler operation are the following:

- Increase in the unburned carbon content of the fly ash exiting the boiler. This is termed loss on ignition (LOI). NOx reduction capability using LNBs is sometimes limited by tradeoffs with LOI levels. High LOI can result in the inability to sell the fly ash.
- Water wall corrosion can increase with the installation of LNBs, especially where the new flame pattern impinges on the boiler wall. During normal boiler operation, an oxide layer forms on the boiler tube surface, and acts as a protective coating. In the fuel rich, reducing environment produced by LNBs, sulfides form instead of oxides on the boiler tubes, which accelerate the formation of iron oxide. The boiler tubes are then attacked by a variety of species, including hydrogen sulfide, carbon monoxide, and chlorine.
- The heat absorption pattern in the furnace can be changed by the retrofit of LNBs with OFA.
- Installations of LNBs can sometimes be accompanied by modifications to the coal pulverization and distribution system. This may require close attention to control of the coal/primary air ratio, coal fineness, and coal distribution to the various burners. Some LNB retrofits have included addition of dynamic classifiers to the coal mills, which can improve coal fineness and distribution control to levels of ±5%.
- New boiler penetrations are typically necessary for the installation of the OFA ports. New ductwork is required to inject the OFA to a point above the primary combustion zone in the furnace.
- Slagging and fouling behavior can also be affected by changing the combustion system due to changes in the ash fusion temperature. This can have a direct impact on the heat absorption rates in the furnace, resulting in overheating or low steam quality in the superheater and reheat sections of the boiler.
- Plugging of burner parts can occur, as well as temperature related damage and warping of burner components.
- Overall boiler efficiency may decrease slightly, resulting in an increase in the heat rate for the unit.

Some of the impacts listed above can be resolved with combustion optimization by modifying the burner settings to obtain the highest levels of NOx reduction while minimizing the negative impacts on boiler operation.

<u>NOx Reduction Capability of LNBs with OFA</u> – The large number of parameters that impact the NOx emission rate make it impossible to predict the specific reduction efficiency for a LNB/OFA retrofit. It is also not feasible to generalize any optimum design rules or relationships between furnace types, volume and combustion system. Previous data from past utility boiler installations has demonstrated that retrofit Low NOx Burners alone can reduce NOx emissions between 30-55% depending on the boiler configuration and tuning that has previously been completed on the specific unit. When combined with Over-Fire Air, this range of removal efficiency capability has been extended to 35-70%, again depending upon the boiler characteristics. For the purposes of this analysis, the combination of LNBs with OFA was assumed to be capable of 50% NOx reduction on the Entergy units.

<u>Maintenance Issues</u> – Changes in the coal feed system may require more attention to be paid to the instrumentation used to monitor the coal milling and feed system. Monitoring of the

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flame detection equipment may also be required on a more frequent schedule. The burners themselves must be maintained on a regular basis to ensure that they are not being subject to excess temperatures or plugging conditions.

Advantages of LNB/OFA:

- Provide moderate levels of NOx reduction for lower cost than other technologies.
- No reagent is required.
- Good turndown capability with the new equipment.

Disadvantages of LNB/OFA:

- Control of coal and air feed rates to each burner will become more critical.
- Boiler efficiency may decrease.
- Increases in carbon content in the fly ash can occur, reducing the marketability of the fly ash.
- Slagging and fouling may increase.
- The corrosion rates for the boiler tubes may increase.
- New boiler penetrations are typically required for OFA injection.
- Operating at optimum combustion conditions will become more critical following the retrofit of the LNB/OFA system.

LNB/OFA Commercial Status - LNBs have been installed on utility boilers since the 1970's. They have been integrated with the operation of OFA systems over the last two decades to further reduce the NOx levels leaving the boiler. LNBs have been applied to all types of boilers that use conventional pulverized coal burners. OFA systems have been used to spread the burning zone and complete the combustion process in all types and sizes of units. The OFA concept has been applied through the use of close-couple air injection with ports installed close to the top row of burners, or in some cases by using the top row of burners as air-only injection ports. In advanced systems, separate air injection ports are installed through the boiler tube wall to provide more separation and further spread of the combustion zone. This concept has been used extensively over the last 10-15 years. The magnitude of experience with this technology throughout the utility industry makes this technology readily applicable to the Entergy coal-fired boilers where reliability maintains a high premium when selecting a control system for these units that are critical to the Entergy system.

NOx Control Alternatives - The emission reduction scenarios that face Entergy in the future could include requirements where only 20-65% NOx reduction is required. With reduced removal, a variety of other control options can be considered that provide control efficiencies up to 60% reduction. Some combination of these process options could prove to be the most cost effective alternative for Entergy to meet the future emission limits. Appendix A provides a listing of the commercial technologies that exist in the market for coal-fired utility boiler applications. Performance capabilities of some of these systems are provided in the following table.

Commercial NOx Control Technologies - The following material provides brief descriptions of additional NOx control options. The emission regulations and the unit operating projections over the coming years will directly impact the applicability of control technologies to each facility and/or unit:

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Combustion Modifications for NOx Control - Burner upgrades and other combustion modifications such as air staging, overfire air, fuel staging, combustion tuning, and reburning technologies are often termed primary control methods. These processes typically reduce peak flame temperatures, lowering thermal NOx formation, while at the same time increasing the concentration of hydrocarbon radicals (radicals aid in the reduction of the nitrogen oxides formed during the combustion process). The following material describes additional primary control methods.

- Excess Air Control = 0-20%
- Boiler Tuning = 0-20%
- Flue Gas Recirculation = 10-20%
- Natural Gas or Coal Reburning = 40-60%
- Natural Gas Reburning with FGR = 55-65%
- LNBs with Natural Gas Reburning = 60-70%
- Neural Networks = 10-30%

Descriptions of each of these technologies are provided in the following material. It should be noted that some of these systems are well suited to applications in series on the same boiler. The removal efficiencies provided above are typical of the performance that has been obtained at other installations. However, boiler configurations and other site-specific issues may result in removal efficiencies that fall outside the ranges provided above.

Excess Air Control – This basic control method reduces the level of excess air at the initial stages of combustion, leading to lower NOx formation rates. Reductions in excess air can also lead to secondary problems, including increased carbon in ash, increased levels of carbon monoxide, reduced boiler efficiency, boiler slagging, increased corrosion rates, higher opacity, negative impacts on ESP performance, and the potential for fires in the air preheater and ash hoppers. Newer technologies can reduce the excess oxygen available in the flame while minimizing these negative operating characteristics.

Boiler Fine Tuning – Fine-tuning requires a detailed evaluation of the boiler combustion settings, including mill fineness adjustment, air and coal flow balancing, air registers, tuning the firing configuration, and improving the control system for the burners. Typically tuning will be combined with a simultaneous reduction in the excess air. The major negative impact of this method is the potential for an increase in the plant heat rate.

Flue Gas Recirculation - In this system, flue gas is recirculated into the furnace or burners using 20-30% of the total flue gas flow from the boiler. The recirculated flue gas is mixed with the combustion air, diluting the flame and thereby decreasing the flame temperature (reducing the rate of thermal NOx formation). When injected into a low NOx burner, the rate of flue gas recirculation is limited by flame stability, flame impingement, boiler vibration, and fan capacities. Worldwide more than 50 coal-fired utility units have used flue gas recirculation for NOx control. The equipment requirements for a gas recirculation system include ductwork for gas extraction, a recirculation fan, a collection system that removes fly ash from the gas prior to

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000729

reinjection, and control system modifications. Potential negative impacts can include major changes in heat distribution in the boiler, flame instability, and increased steam temperatures. By itself, flue gas recirculation can only achieve up to 20% NOx reduction. When combined with overfire air, NOx reductions of 30-50% have been reported in gas-fired units.

Fuel Staging/Reburning - Fuel staging can take many forms, from modifying or shutting off the fuel flow to individual burners (burner out of service or fuel biasing designs) to the use of reburning technology. Changing the fuel feed rate to various burners can be used to produce fuel-rich and fuel-lean zones within the furnace. NOx reductions of up to 30% have been achieved using this technology.

Reburning has received the most attention recently due to demonstrated NOx reductions in excess of 60%. Combustion is effectively divided into three stages in a reburn system: primary combustion zone, reburn zone, and burnout zone. Reburning requires the injection of some fraction (typically 10-30%) of the fuel input into the upper furnace through ports located above the primary combustion zone. Close-coupled reburning has also been employed in wall- and tangentially-fired boilers. In this design, the new fuel injectors are replaced by using the existing burners to inject the reburn fuel. Final system designs will be different from one boiler to the next depending on the furnace arrangement.

Natural gas has been the reburn fuel of choice in past applications because it results in reductions in particulate matter, SO_2, and CO_2 emissions. Oil, pulverized coal, and micronized coal (less than 43 microns) have also been considered in recent test programs. The additional fuel consumes the remaining excess oxygen and also converts the NOx in the flue gas to nitrogen. The secondary fuel breaks down in this oxygen-depleted environment to form hydrocarbon fragments that react with NOx, reducing it to nitrogen gas. In some cases, recirculated flue gas is used to carry the reburn fuel, further increasing the cost and complexity of the system.

Additional air injection ports are typically required in a reburn application to complete the burnout of the reburn fuel and carbon monoxide. The major negative impacts are changes in boiler heat distribution and potential reduction in boiler combustion efficiency. The cost of the reburn fuel can also cause a major increase in unit operating costs. Equipment requirements would be a feed system for the reburn fuel, and additional air duct and a booster fan for the final air injection.

Advanced Gas Reburning - This recently introduced technology combines the NOx reduction chemistry from both gas reburning and selective non-catalytic reduction (SNCR). In this design, 10-20% of the fuel is fed to the upper furnace. Urea, ammonia or other nitrogen compounds are then injected to drive the SNCR reaction process. Further discussion of the SNCR technology can be found in the sections dealing with secondary NOx control options. Although this technology has demonstrated up to 80% NOx reduction efficiency in small unit tests, recent applications on large utility boilers achieved only 45-50% reduction.

Computerized Combustion Tuning/Neural Networks - In the past, improvement in combustion performance systems relied almost entirely on the experience of the

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
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operators and a limited amount of operating data. The availability of high-speed computer hardware and neural network software systems now allow the combustion process to be evaluated on a continuous basis.

Neural networks establish a set of mathematical relationships that attempt to "learn" how operating conditions and set points effect emissions and boiler performance. By analyzing test data, the neural network develops a series of non-linear algorithms that map system inputs to corresponding outputs. The results of these calculations are then fed to minimization equations that optimize the system performance. The development of computational fluid dynamic software and supporting operating systems allow three-dimensional modeling of the complex combustion process. These models evaluate the combustion kinetics and fluid dynamics in the flame zone using finite element analysis of the following parameters:

- NOx emissions
- Temperature distribution
- Air to fuel ratio
- Unburned carbon in fly ash
- Furnace gas exit temperature

The neural net essentially mimics the abilities of the operating personnel, but carries out the complete furnace combustion analyses in real time, i.e., every half-second or less. As a result, the boiler is continuously tuned to maintain optimum combustion conditions. NOx reduction efficiencies of 20-50% have been demonstrated at multiple full-scale installations.

Neural networks require the purchase and maintenance of an additional computer operating system. In addition, a large amount of instrumentation and automated systems equipment may be required to allow the computer system to control individual components (using much more data than is typically found in a utility control room). Operating staff must be retrained to use the new equipment. The network acts as an artificial intelligence/expert system, learning as it gains more knowledge of cause and effect relationships of a specific boiler system.

A number of software packages have been developed and tested over the last 10 years, including:

- Furnace Simulation Model by the Electric Power Research Institute (EPRI) and Radian,
- Ultramax Method by EPRI and Ultramax Corporation,
- Generic NOx Control Intelligent System (GNOCIS) by PowerGen, Southern Company, and EPRI,
- NOx Advisor by Lehigh University's Energy Research Center (funded by EPRI and PEPCO),
- NOxSMART by TransAlta Utilities, and
- NeuCo boiler evaluation system.

These neural network packages have demonstrated the ability to reduce NOx emission rates by 10-30% (up to 50% claimed in published reports), while maintaining gas exit temperatures, boiler performance, and unburned carbon limits. In general the neural

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network technology is combined with combustion tuning (previously discussed). Actual performance at a specific unit is a function of the current level of performance of the operating staff and the control/instrumentation system capabilities of the unit.

Secondary/Post Combustion NOx Control Alternatives - Secondary control systems are located downstream of the primary combustion zone. They can be used independently or in combination with primary control systems. These processes typically use ammonia or urea to react with the NOx in the flue gas to reduce it to molecular nitrogen. The secondary control systems included in this section are Selective Non-catalytic Reduction (SNCR), a hybrid combination of SCR & SNCR and other developing technologies that are not fully commercialized at this point.

There are many other secondary control technologies on the market at varying stages of development. However, these developing systems are not commercially proven, so they are not included in this section.

Selective Non-Catalytic Reduction (SNCR) - SNCR was originally developed in Japan in the 1970s for use on oil- and gas-fired units. Coal plant applications began in the late 1980s in Western Europe. Commercial U.S. installations on coal-fired utility boilers started in the early 1990s. More than 2 GW of capacity have been installed on coal-fired plants worldwide. SNCR requires injection of ammonia or urea into the proper temperature window within the back-pass of the furnace. The ammonia or urea reacts with NOx species to form nitrogen and water. Emission reduction capabilities range from 25% at 5-ppm ammonia slip to 30% at 10-ppm ammonia slip in most commercial installations

An SNCR system will require the installation of reagent storage and transfer equipment, a multilevel injection grid and the necessary control instrumentation. Due to the elimination of the catalyst used in the SCR process, the SNCR consumption rates for ammonia or urea are typically 3-4 times the rates required for an SCR system on a per mole of NOx basis.

The gas temperature at the point of injection is critical to the NOx reduction performance of an SNCR system. This window falls in a range of 1600-2000°F with an optimum temperature of approximately 1800°F. Above this temperature, ammonia begins to thermally decompose and below this temperature, the reaction rate for NOx reduction decreases, resulting in increased ammonia slip. The temperature profile in any given boiler changes with changes in boiler load. Therefore, the optimum injection point will move during cycling operation and multiple injection points will be required. It should also be noted that the longer the ammonia or urea is maintained within the optimum temperature window, the higher the NOx reduction that is achieved. Residence times in excess of one second are desirable to achieve the maximum reduction efficiency. The minimum residence time is approximately 0.3 seconds for moderate performance. However, most large utility boilers have heat transfer surfaces (pendants and platens) positioned in this flue gas temperature zone. This will reduce the effective use of the SNCR system, even if multiple injection levels are installed. In some cases, these internal obstructions will make the application of SNCR impractical.

Controlling the injection of the ammonia or urea is critical to performance of the SNCR system. Continuous ammonia slip measurements would allow direct control of the

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ETR_00000732

injection rates, but reliable equipment for ammonia measurement is not currently available commercially. The location of the injection ports must also consider the distribution of ammonia across the furnace cross section. Multiple injection zones and levels are typically required in a coal-fired application to account for the large volume within a coal-fired furnace.

A common electrical supply system provides power to the ammonia pumps and controls. New electrical components will typically be necessary, including an MCC and new switchgear. Alarm/monitoring signals are wired to the nearest continuously manned control room.

One of the major problems associated with ammonia slip is the formation of ammonium bisulfate due to reaction with SO_3 in the flue gas. This compound will precipitate at air heater operating temperatures and can lead to fouling and plugging. Also a concern is the formation of N_2O during the SNCR reactions. Urea injection typically leads to higher N_2O production rates. N_2O formation rates increase as the rate of NOx reduction increases.

Additives and enhancers have been tested to improve SNCR performance. Some are designed to expand the optimum temperature window (using methane), while others are designed to lower the temperature at which the reaction will occur. The use of additives was not considered in the SNCR evaluation.

For SNCR installations, the actual NOx removal rate is strongly influenced by the CO level in the injection zone. Variations in the CO concentration can move the temperature window where the urea reaction chemistry performs adequately. Therefore, unit load, burner firing pattern, and localized CO concentration are additional variables that increase the complexity of SNCR system control.

SNCR Process Issues/Considerations --

- NOx Reduction – Compliance planners considering the use of SNCR need to be realistic and conservative to assure minimal ammonia slip. Unreacted ammonia combines with SO_3 to form ammonium bisulfate that precipitates out at temperatures of 450-400°F and fouls/plugs air preheater surfaces. Also, industry experience with SNCR technology has been mixed.
- Injection Locations – Necessary to locate in temperature zone equal to or greater than the optimal reaction temperature of approximately 1,800°F, but not greater than the ammonia decomposition temperature of 2,000 - 2,100°F to maximize reaction time and NOx removal. For conventional SNCR this requires multiple injection locations and levels (2-3 dozen) and staggered operation.
- Residence Time – 1-2 seconds is desirable. 0.3 seconds is minimum. This is difficult to achieve in the upper furnace and furnace outlet amongst platen and pendant heat transfer surfaces.
- Carbon Monoxide - CO concentrations in the injection/reaction zones influence optimum reaction temperature and consequently NOx removal. Elevated CO levels shifts the optimal temperature for NO reduction to a lower temperature.
- Firing Patterns and Unit Turndown - Even at constant boiler load varying firing patters can affect furnace temperature profiles and localized CO concentrations.

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ETR_00000733

NOx removal at lower unit loads requires reagent injection at lower furnace levels.

- ESP Performance - ESP performance may be enhanced or diminished due to factors such as ammonia slip, air in-leakage and changes in flue gas flow rate and temperature.
- Unit Heat Rate Impact - Properly designed and controlled, SNCR should have little or no impact on unit heat rate. A very small amount of furnace heat is required to vaporize the ammonia or urea reagent. Furnace heat is also removed by the SNCR cooling system required to protect the injection nozzles and lances. Variations such as the Mitsui Selective Autocatalytic Reduction system, a variation on the standard SNCR technology that uses natural gas injection to expand the applicable temperature window, could actually improve the unit heat rate.
- Furnace Temperatures, Heat Absorption, Heat Transfer, Geometry, Modifications, Etc. - Detailed furnace physical design and operation information is required to model furnace temperature profiles for the purpose of locating injection lances. Additionally, furnace outlet physical design and operating information may be required for platen and pendant surfaces, as well as plans for current and future coals, if different than the original design coal.
- Balance of Plant - Electrical System, Controls, Utilities, etc.

Hybrid SNCR/SCR - This system combines the NOx reduction capability of SNCR in the boiler with the installation of an SCR catalyst downstream to use the ammonia slip from the SNCR process. The major problem with this process is adequate distribution of ammonia to the SCR catalyst. Control is difficult due to varying NOx distributions in the flue gas. Therefore, inlet NOx concentrations at the catalyst face may be much lower than design levels, resulting in ammonia passing through the catalyst unreacted. High local concentrations would have insufficient ammonia for reaction, resulting in reduced NOx reduction efficiency. Some hybrid systems may use a supplemental ammonia injection system to ensure sufficient ammonia feed to the SCR catalyst. If an ammonia injection system is required, then the cost for the total system will approach that of a full-scale SCR system.

NOx reductions typically fall in a range of 50-60% for this hybrid system, although some test programs indicate that up to 90% NOx removal is technically feasible with this combined system. The primary reason for including the hybrid design in any evaluation is the potential for cost savings versus a full-scale system. As the ammonia maldistribution increases downstream of the SNCR subsystem, then the volume of catalyst required will also increase. At some point, the cost savings from reduced catalyst volume will be more than offset by the higher chemical feed costs associated with an SNCR system. The purpose of the hybrid design is to increase the SNCR removal efficiency from 30% to 50-60% while at the same time reducing the ammonia slip rates to 5 ppm or less and also reducing the ammonia or urea feed rate by 30% or more. Demonstration tests have shown the potential for this design, but it should not be considered a standard commercial offering at this point in time.

Other Options - Fuel switching and unit load modifications have been used at some facilities to meet the required NOx emission limits. Switching to natural gas would not be economically viable due to the cost differential between the two fuels. Another

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ETR_00000734

option is coal reburning. This process has been tested on some small boilers. However, it is relatively expensive for the amount of NOx removal that it achieves.

Developing NOx Control Technologies - Air pollution control vendors, researchers, and developers are constantly investigating alternative methods to control NOx emissions from power generation systems. When new regulations are proposed, the promotion of these alternate control processes increases. The following material provides brief descriptions of some of the technology options that were recently proposed or offered in the past. Most of these systems have never been installed on full-scale commercial plants. In general, these systems will require something on the order of 5 to 10 years of development before they will be suitable for utility applications. This section discusses these systems to ensure that most of the available technologies have been assessed during the course of this project and so that some promising alternative was not missed that could influence the final conclusions.

A listing of the developing technology options is provided in Appendix A. Some of these are briefly described below:

Ashworth Combustor – This design is being developed by ClearStack Combustion Corp. In this system, the first stage of combustion occurs in a small coal gasifier(s). These gasifiers replace the existing circular burners. The coal is partially oxidized at a stoichiometric ratio of 0.6 and enters the furnace at 60 Btu/scf. The gases then complete combustion in two additional stages of combustion (0.9 and 1.2 stoichiometric ratios, respectively. The largest scale test was at 33 MW on a cyclone-fired boiler. Process modifications continue with the addition of steam injection and burner modifications to increase gasification rates. The process is potentially years from becoming a commercially proven system suitable for utility applications.

NOxTECH – This process has been demonstrated on a 2.8 MW diesel generator. NOx was reduced by gas-phase reactions at temperatures of 1400°F to 1550°F. Natural gas is injected concurrently with ammonia or urea. The multi-thousand-point injection grid may be located in the convection path of a coal-fired boiler. Ash pluggage/buildup on the grid is a major concern, and it cannot be recommended for any near term commercial applications on a coal-fired boiler.

Catalytic Reburning – This laboratory scale concept is focused on the development of a non-metal rare earth oxide catalyst that will reduce NOx in the presence of excess air and methane, carbon monoxide or hydrogen. Once again, commercialization is years away.

Low Temperature SCR – Low temperature (300° to 500°F) vanadium catalysts will cost more than medium to high temperature catalysts due to the reduced activity of vanadium at these lower temperatures. Therefore, more catalyst volume will be required to obtain the same level of NOx removal. The development of this process was directed at HRSG applications where the cost to insert the SCR catalyst in a higher temperature zone was felt to be too costly.

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ETR_00000735

Additional low temperature catalyst development was conducted at Lehigh University. The process uses a catalyst/sorbent containing rhodium chloride and hydrofluoric or acetic acid on a gamma aluminum matrix. The alumina would reversibly absorb the SOx preventing it from poisoning the noble metal catalyst. Palladium and platinum are alternate catalysts. The process was envisioned as honeycomb catalyst inserted into the baskets of a device similar to a Ljungstrom air heater. It was designed to remove both SOx and NOx, with catalyst regeneration producing a byproduct stream of sulfuric acid. The gas velocity would be 90 fps versus a typical 15 fps for a standard SCR reactor. The stoichiometric feed rate for hydrogen should range from 1 to 3, but the specific feed rate has not been determined. The pressure drop addition was expected to be 9" water gage. Potential problems include the formation of N_2O and the residual hydrogen levels in the flue gas. Also, initial tests indicated that a pre-sorbent might be required to prevent SOx poisoning. The actual gas velocity of a full-scale installation may also have to be much lower than was possible in initial laboratory testing. The process is years from commercial application in a utility boiler application and, per a 1993 EPRI report, did not offer significant advantages over a standard SCR installation.

Water Injection – The test results for this technology are pending.

SCR with Ozone Reagent – This process was recently patented and will require a significant period of development prior to commercial application. The production of ozone will use large amounts of parasitic power, and the process produces a waste stream of nitric acid requiring additional waste treatment facilities.

EBARA/E-Beam System – This process was originally designed to remove both SOx and NOx through the use of a high intensity electron beam to break apart the molecules into their atomic constituents. These atoms of nitrogen and oxygen would then return to their molecular state as they exited the beam chamber. NOx removal was limited to 20% unless combined with some form of reburn technology (to 65% removal) or with ammonia injection (to 70-90% removal). The process consumes approximately 3% of the plant power output. Full-scale commercial units have been installed at a 220 MW unit firing high sulfur oil. The limitations of the process and the parasitic power consumption resulted in its rejection from further consideration.

Most of the remaining systems are still in the early stages of development and are a minimum of 5-10 years away from commercial application. Others that originally showed some signs of promise have been withdrawn from the market by the process developers. The primary reasons for new process failures are their inability to compete with current commercial technologies when the economic evaluations are done using a consistent estimate basis for the comparison.

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The following tables provide a summary of the potential control efficiencies and a relative cost comparison for various NOx control processes.

NOx Removal Process	Relative Control Cost (preliminary) Sept. 2004 $'s/Ton NOx Removed
Combustion Tuning	75
Over Fire Air	700
Neural Network	400
SCR	3000
Coal Reburn	600
SNCR	2000
Hybrid SCR/SNCR	3400
AEFLGR*	3100
Natural Gas Reburn	4800
Advanced Gas Reburn	4400

*Amine-Enhanced Flue-Lean Gas Reburn

Table 3-7. NOx Control Technology Limitations

NOx Control Process	Requirements	Limitations	% NOx Removal
Combustion Tuning	Modify operating settings	Many units are already tuned to optimum conditions – can result increase in heat rate	10-15%
Induced FGR	20-30% flue gas recirculation	Sometimes fan limited	20%
Low NOx Burners	Install new burners	Higher performance achieved with over-fire air	30-50%
SNCR	Ammonia/urea feed and boiler penetrations	Requires a specific gas temperature Load variations can reduce effic. – also higher ammonia slip than SCR.	20-30%
SCR	Ammonia feed, reactor vessel, fan upgrades, catalyst	Needs large area for equipment and requires catalyst replacements – also performance varies with gas temperature	70-90%
Natural Gas Reburn	Natural gas supply and boiler penetrations for injection ports	High gas consumption rate	30-50%
Mobotec	ROFA – air fans and boiler penetrations Rotamix – urea/ammonia feed	Rotamix is currently being reengineered to achieve higher removal – performance varies from one unit to another	40-80%
Over Fire Air	New air ports	Separation from fuel burners helps to achieve higher efficiency	20-30%
Neural Network	More boiler instrumentation and turning the operation over to the computer control system	Neural net effectiveness varies from one unit to the next	10-30%
Coal Reburn	Separate coal feed system to location above existing burners	Relatively new technology with limited operating history	30-50%
Hybrid SNCR/SCR	Boiler penetrations for ammonia/ urea injection and catalyst installed in downstream duct	Limited operating experience – designed to improve efficiency and reduce ammonia slip	50-60%
AEFLGR	Amine supply and natural gas	Variable performance and limited full-scale operation	40-50%

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MERCURY CONTROL

The only technology that is currently commercially available and previously installed at coal-fired utility boilers is the activated carbon injection process. When combined with a Compact Hybrid Pulse Jet Fabric Filter (COHPAC), the technology has been given the name TOXECON, a system configuration currently patented by the Electric Power Research Institute (EPRI). For this analysis, Washington Group also considered variations on the original TOXECON design:

- TOXECON 1(T1) - Activated Carbon Injection (ACI) with COHPAC (Compact Hybrid Particulate Collector). This system has seen the most field-testing and forms the basis for the commercial offering by the major vendor. Figure 3-6 provides a flow diagram for the TOXECON 1 system. The major components of the TOXECON 1 design would include a pneumatic transfer system for connection to trucks delivering the activated carbon (AC). The pneumatic piping transfers the AC to the storage silo(s) that are equipped with a vent filter and weigh feeders. The feeders transfer the AC to the pneumatic feed lines that move the AC to the injection location. The injection grid is fed by a stream splitter that transfers the AC to multiple injection lances feeding the injection grid installed upstream of the new particulate collector. The solids are ten collected in a downstream COHPAC FF. This FF will add 8-10" w.g. pressure drop to the flue gas at typical air to cloth deign ratio of 4-6 square feet per thousand cubic feet of flue gas treated. The filter media collects the AC solids from the flue gas and provides additional contact time for removal of the Hg. The solids are periodically removed from the FF and pneumatically transferred to a separate silo for ultimate loading onto trucks sent to the landfill. In this case, oly trace quantities of fly ash would be expected in the AC sent to the landfill.
- TOXECON 1.5 (T1.5)– ACI with ESP Field Conversion to Fabric Filter (FF). The T1.5 system will use the same receiving, storage and transport system that is used in the T1 design. In this case, the injection grid will be installed upstream of a PJFF that is installed as a replacement to the last field of the existing ESP. The limited contact time that is available in this configuration will be offset by the use of the PJFF that will act as the gas/solids contacting device. The collection hoppers under the new PJFF will need to be isolated form the existing ESP pneumatic ash handling system so that the ash sales can be maintained. The new pneumatic conveying system will transfer the ash/AC waste solids to a new storage silo, and from there to trucks for transport to the landfill. The PJFF retrofit will require that the existing ESP plates be removed, and the last field of the ESP isolated from the rest of the ESP. New fans will be required to provide the air pulsation to clean the bags. A spare module will probably not be included in the design, so that the PJFF will be cleaned on line. The diagram provided in Figure 3-7 shows the major components of the TOXECON 1.5 and 2 systems. The only major difference is the fact that in the T1.5 design, the last field of the ESP is replaced with PJFF components. This design will also result in higher power consumption than would be expected in the T2 installation, probably resulting in a 6-8" w.g. pressure drop increase across the particulate collector.
- TOXECON 2 (T2) – ACI into the ESP Upstream of Last Field - The T2 system has seen limited testing, with one full-scale test completed at the Coal Creek plant and second test program done at the Pleasant Prairie plant. Mercury removal in these cases was limited to 50-80% at AC injection rates of 5-10 lbs/MMacf. This design should result in reductions in the capital investment required, but may come with a reduction in the removal efficiency capability of the design due to the reduced contact time between the

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ETR_00000738

AC and the flue gas. The AC will collect on the ESP plates, and then drop into the collection hopper located under the last section of the ESP. The T2 system will include the same AC receiving, storage and transfer system that was used in the T1 design. The injection grid for T2 will be installed just upstream of the last stage of the ESP. The collection hoppers below the last stage will have to be isolated from the other ash collection system and the solids will be moved to a new storage silo. From the silo, the AC/ash mixture will be sent to the landfill. This system allows the separation of the AC from the majority of the fly ash collected by the ESP, allowing ash sales to continue without contamination. Approximately 10% of the fly ash will be removed in the last field of the ESP, resulting in lost ash sales.

TOXECON Technology Description and PFD - Table 3-8 provides the basic design criteria for the TOXECON systems as they were evaluated in this report:

Table 3-8. TOXECON Design Criteria

Pressure drop	8 in. H_2O
Hg removals	90%
COHPAC air to cloth ratio	6 acfm/ft^2
Baghouse capacity	1 @ 100% per unit
Spray cooling required	No
Carbon injection	Pneumatic through lances
Carbon supply	Powdered activated carbon @ $1,000/ton
Carbon feed rate	3 lbs/MMacfm for TOXECON 1 (clean gas) 10 lbs/MMacfm for TOXECON 1.5 and 2 (dirty gas)

A process flow diagram for the basic TOXECON system is provided in Figure 3-6. In this scenario, it is assumed that the existing ESP particulate control device will continue to operate upstream of the TOXECON equipment, separating the bulk of the fly ash from the activated carbon. An alternate to the installation of a full-scale COHPAC unit is the retrofit of a smaller PJFF into the last 1-2 fields of the existing ESP. Figure 3-8 provides a comparison of the COHPAC I fabric filter installed downstream of the ESP with a COHPAC II installation that would be used in the TOXECON 1.5 design where the PJFF is added into the last two fields of the ESP. The activated carbon would then be injected just upstream of the COHPAC II as shown in Figure 3-7.

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ETR_00000739

Figure 3-6. Process Flow Diagram for the TOXECON 1 System

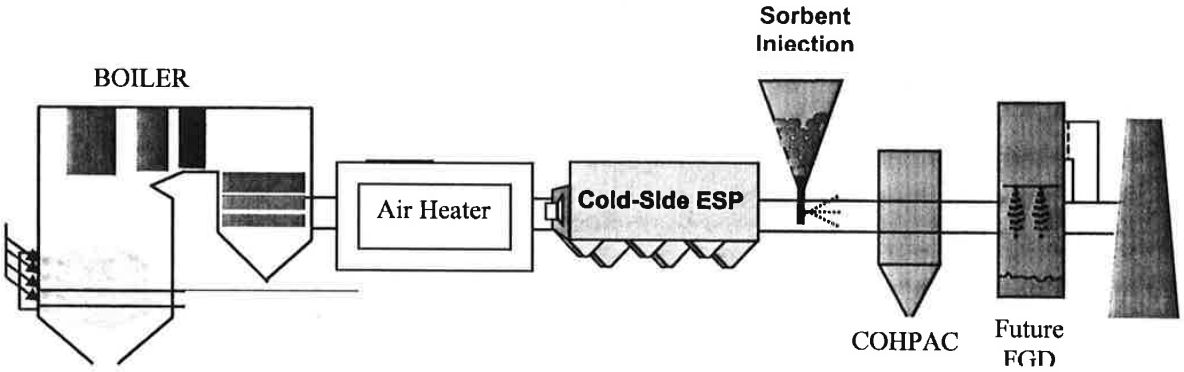

Figure 3-7. TOXECON 2 Flow Diagram (Note: for the TOXECON 1.5 scenario, the last field of the existing ESP is replaced with a PJFF as shown in Figure 3-8 = COHPAC II scenario)

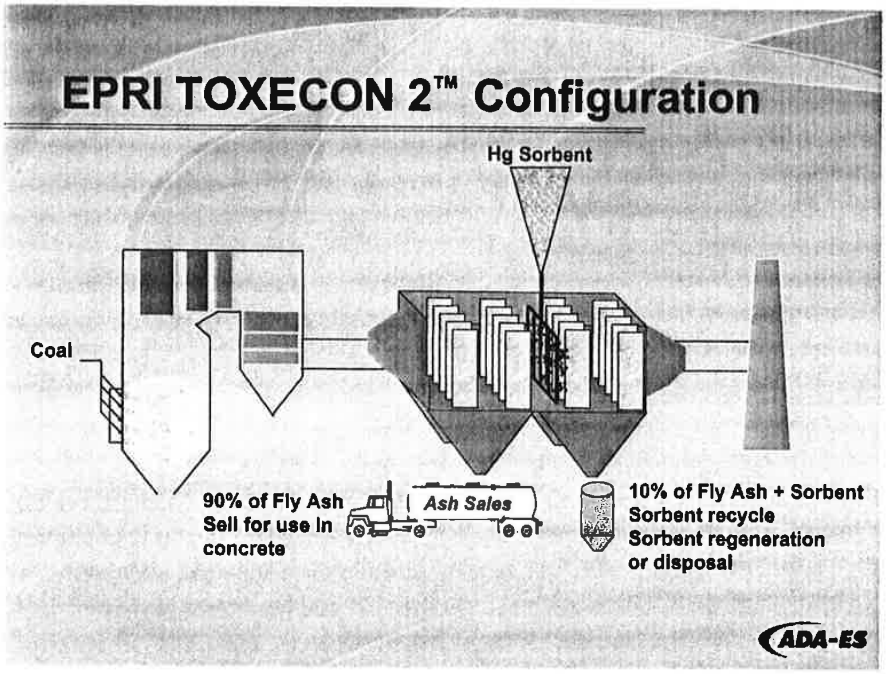

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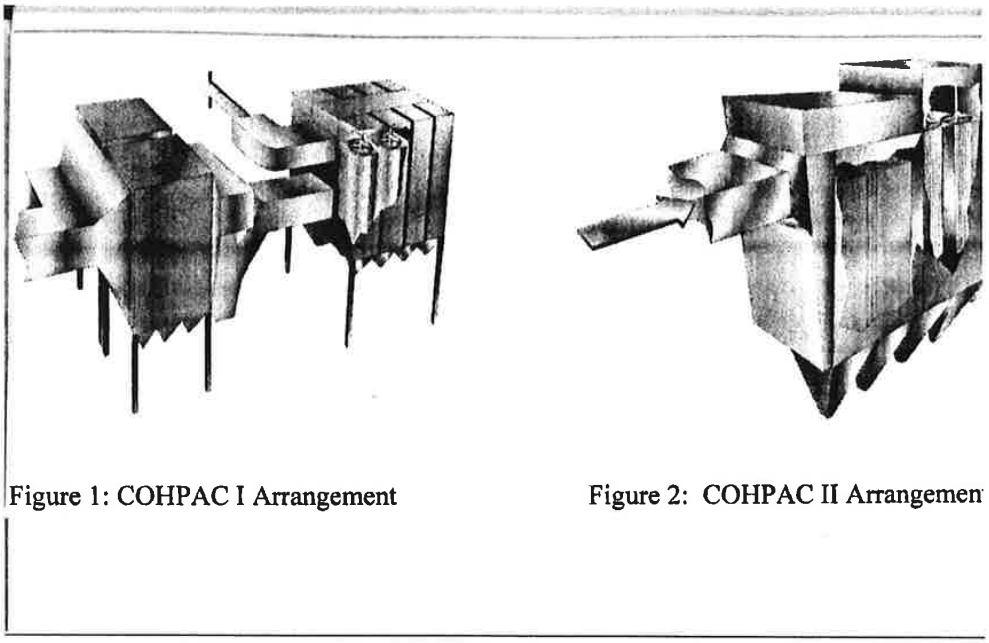
Figure 3-8. TOXECON 1.5/COHPAC II Diagram



TOXECON System Impacts on Plant - The TOXECON systems evaluated in this study includes the following subsystems:

Carbon Storage and Feed System = Designs 1, 1.5 and 2 – Main storage silos take delivery of the activated carbon by pneumatic truck. Each silo is equipped with vent filters to prevent dust from exiting the silo while it is being filled. From the main silos, the activated carbon is transferred to small day bins that feed the pneumatic injection system. This blower system transfers regulated quantities of activated carbon to the injection grid location specific to each TOXECON system.

Solid Waste Disposal - The solids collected in the FF are then sent to a non-hazardous landfill. If the solids were recycled multiple times through the system, then the mercury concentration in the solids could reach a point where the solids might be designated as a hazardous waste.

Mercury Removal Capability – Curves generated during multiple utility pilot test programs have shown some variation between sites for the TOXECON 1 design. The rate of injection required to achieve a specific level of control will vary widely depending upon the fuel characteristics, operating gas temperatures, source of activated carbon and other undefined parameters. Injection rates typically vary from 1-30 pounds of activated carbon per million actual cubic feet of flue gas treated. Removal efficiencies at some sites have reached 90% while injecting carbon at a rate of 3 lbs/MMacfm. Results of some of these full-scale field tests can be found in various EPRI reports and ADA-ES papers presented at industry conferences.

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ETR_00000741

The TOXECON 1.5 and 2 designs have undergone more limited field-testing. For the purposes of this evaluation Washington Group assumed that all three TOXECON designs were capable of achieving 90% Hg removal, but with more reagent required for the 1.5 and 2 designs due to the presence of dirtier gas at the point of injection than in the TOXECON 1 design, and the lack of a full-scale FF downstream to extend the gas-solid contact time.

COHPAC Fabric Filter = Design 1 – A Compact Hybrid Particulate Collector (COHPAC) is a smaller version of a standard pulsejet fabric filter. The air-to-cloth ratio for the COHPAC unit is 2-3 times that used for a standard pulsejet FF. This allows the unit to have a smaller footprint, and the total bag requirement is reduced significantly. This unit is used to capture the activated carbon that is injected for mercury capture. In some cases, it may be cost effective to recycle this carbon back to the injection grid to supplement the carbon feed. To-date, the system supplier, ADA-ES LLC, has not recommended solids recycle. The only major maintenance issue identified to-date is the fact that the COHPAC filter bags are expected to have a shorter life than bags installed in a standard pulse jet FF. Replacement may be required every 12-18 months due to the increased rate of cleaning cycles that are necessary for this higher air-to-cloth ratio application.

Advantages and Disadvantages of ACI/TOXECON – The following material summarizes the potential advantages and disadvantages of the ACI/TOXECON technology for use as a utility mercury control system:

ACI/TOXECON Advantages:

- Activated carbon injection is the only system on the market today that has been demonstrated at multiple full-scale installations firing various coals
- The ACI process is currently being offered by a vendor willing to provide process performance guarantees.
- The mercury adsorption occurs very quickly once injected into the duct or upstream of the last field of the ESP, resulting in only a short residence time (less than 0.5 seconds) required upstream of the final particulate collection device.

ACI/TOXECON Disadvantages:

- The ACI process requires the use of an expensive feed material (pulverized activated carbon with a current price of approximately $1,000/ton and future costs projected to be closer to $700/ton).
- Injection of activated carbon upstream of an existing particulate collection system will result in contamination of the fly ash, potentially making it unmarketable. For that reason, variations of the TOXECON system were included in the current evaluation to maintain the marketability of the fly ash at all plants.
- Testing has shown that some activated carbons perform differently than others due to their adsorption capacity
- Research is continuing to confirm basic design parameters impacting performance for all three TOXECON designs
- Only one vendor is currently offering process performance guarantees on the TOXECON 1 system, limiting the competitive market. TOXECON 1.5 and 2 designs are still under development.

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ETR_00000742

Activated Carbon Injection/TOXECON Commercial Status - The activated carbon injection process has received development support from both the government and utility research groups. Multiple full-scale test programs have demonstrated the ACI system's ability to reduce mercury from coal-fired flue gas by as much as 90% regardless of the type of Hg present (oxidized or elemental). However, performance from one site to another has shown significant variability, indicating that the parameters affecting performance are not fully understood, and that mercury measurement techniques, especially continuous monitoring equipment and the sample conditioning systems, are still in need of further development. The TOXECON 1 process in this case combines ACI with the installation of a PJFF, usually a COHPAC unit that is designed at a higher air-to-cloth ratio than a standard pulse jet system. TOXECON 1.5 and 2 designs will require modifications to the existing cold-side ESPs, potentially leading to extended plant outages for the installation of the FF in the last field of the ESP in the case of the TOXECON 1.5 design. However, some vendors have indicated their ability to complete this conversion during limited outage periods. Further development work is needed to confirm current performance and schedule projections for TOXECON 1.5 and 2 options.

Mercury emissions from each Entergy unit would vary with the control requirement ultimately established by future regulations. Assuming that 90% control of Hg at each unit was achieved, the following Hg emission rates would be expected when operating at an 85% capacity factor:

- Independence 1 and 2 = 38 lbs Hg/year
- White Bluff 1 and 2 = 52 lbs/year
- REDACTED

COAL DRYING SYSTEM

Great Rivers Energy has demonstrated the ability to reduce the moisture content of subbituminous and lignite coal on-site using waste heat from the plant, thereby decreasing the amount of water that must be vaporized in furnace, and resulting in an increase in the heating value of the coal. The process developer estimates that a utility boiler can realize 2.8-5% efficiency improvements, while simultaneously reducing all primary pollutants and carbon dioxide. Preliminary assessments (review of the test data provided from the DOE test program, and running performance calculations with the new coal composition) of the impact of reducing the coal moisture by 25% indicate that the actual improvement in plant efficiency might be closer to 1-2% for a subbituminous coal, and possibly 3% for lignite fuels. A 2% efficiency increase was assumed for the economic analysis of this technology. Higher efficiency improvements might be obtained for higher moisture fuels.

The reduction in the amount of fuel required to achieve the same furnace heat input will directly reduce the amount of SO_2, NOx, CO_2, ash, and mercury carried in the boiler flue gas. The statements received from the vendor state that SO_2 reductions of 25% could be achieve by this system. This level of performance is 3-4 times higher than the expected reduction in coal fired in the boiler, and does not appear to be justified by the limited data received to-date. For the economic analyses provided in this report, it has been assumed that the SO_2 emission rate will be reduced by only 7%, the same reduction in the coal feed rate and the reduction efficiency for all the other major pollutants.

Figure 3-9 and 3-10 are process schematics for the GRE Coal Drying system. The major components include a fluidizing coal dryer that uses waste heat from around the plant to heat the coal and drive off approximately 25% of the moisture in the coal. Other major components are the baghouse for collection of the fine solids that are carried out of the dryer by the fluidizing air, the fans required to extract heated

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air from some point in the existing gas path, and the pumps needed to move heated water to the heat transfer tubes located in the dryer vessel. Numerous design assumptions were required due to the limited amount of information that was available in the presentation material provided by Entergy and other public domain information sources. The large volume of air assumed for the fluidizing dryer will require the installation of a relatively large pulsejet fabric filter to remove the fine particle carryover, and the capital cost for this system is high in comparison to the other major components. The final design of this subsystem for installation at one of the Entergy plants might be very different from the conceptual designed assumed for this evaluation. A photo of the coal drying demonstration facility is provided in Figure 3-11.

Figure 3-9. Coal Drying System PFD

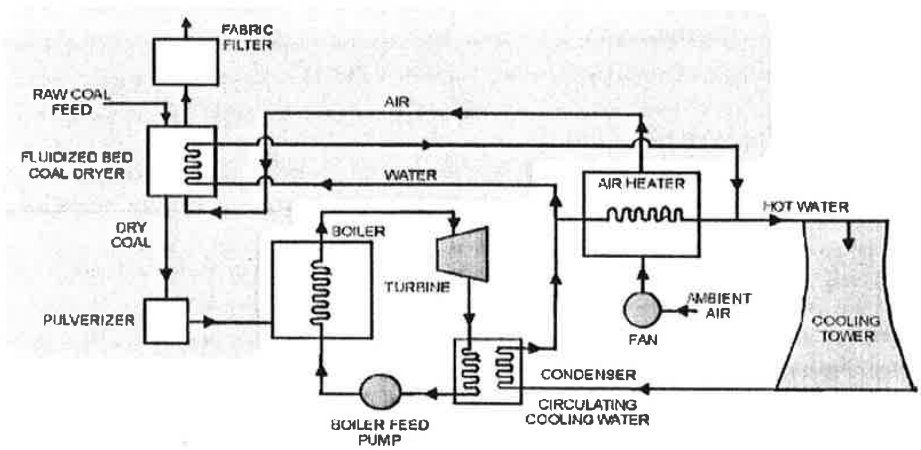
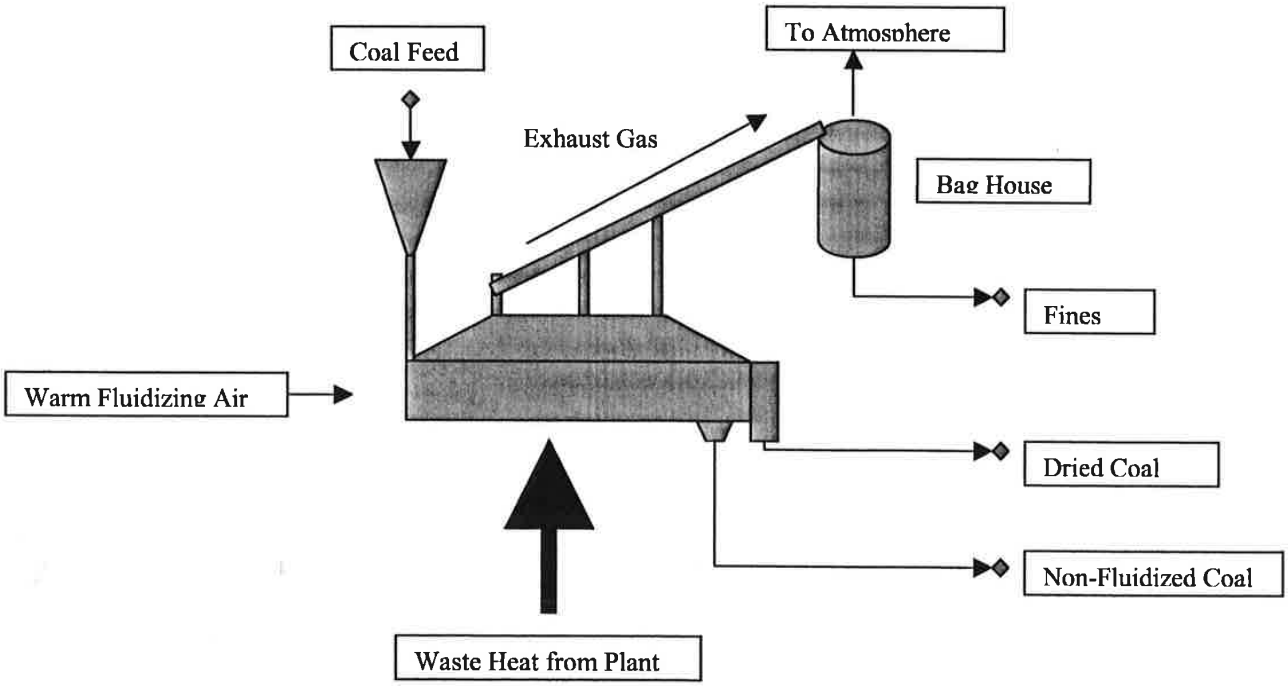


Figure 3-10. Conceptual Design of the Coal Dryer System



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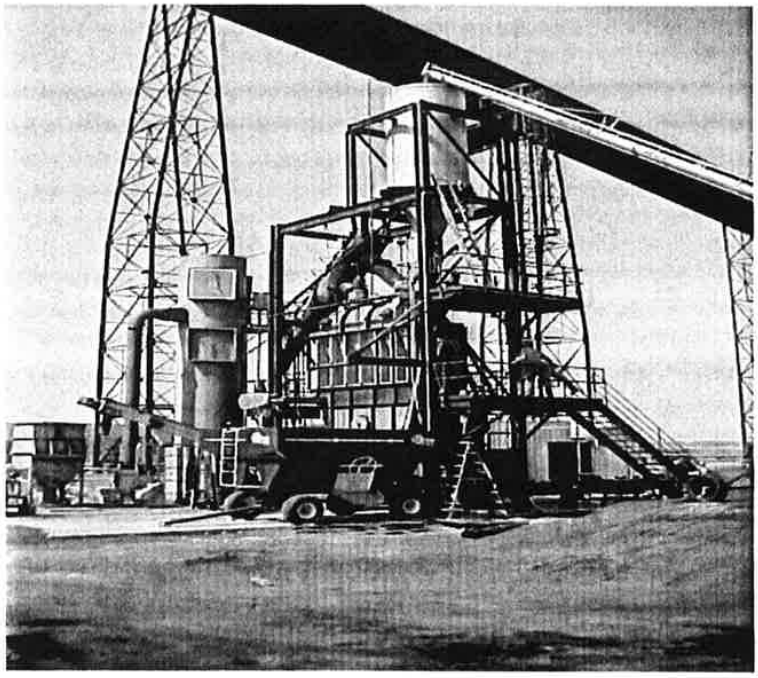
ETR_00000744

Figure 3-11. Photograph of the Pilot Dryer Located at the Coal Creek Plant



3.6 Economic Criteria

Plant Performance Requirements

The emissions control equipment must meet the following performance requirements:

Plant Operating Period	12 months/year
Sparing Philosophy	Include spare parts for critical components
Capacity Factor	See tables

Economic Criteria

Tables 3-9 and 3-10 give the economic criteria that served as the basis for the cost estimating and economic analysis:

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ETR_00000745

Table 3-9. Economic/Site Factors for Entergy Generating Stations

Estimate Basis – Date	September 2004
Plant Life After Retrofit	20 years
Average Escalation Rates Capital O&M/Chemicals Fuel/Power	 2% 2% 2%
Nominal Discount Rate	7.5%
Nominal AFUDC Rate	5.09%
Fixed Charge Rate First-year Levelized	 7.62% 10.5%
Federal Tax Rate	30%
State Tax on Pollution Control Equip.	Exempt
General Facilities (% of TPC)	10%
Contingency	Process dependent
Construction Period	Option dependent
Retrofit Factor	1.3
Wind Load	100 mph (ANSI Standard 7/95)
Foundations	Site specific – See Table 3-1
Soil Conditions	Unit Specific – See Table 3-1
Rail Access	Available at all sites
Plant Altitude	Site specific See Table 3-1
Site Steam Conditions/Cost	Medium pressure = High pressure =
Standard Conditions	60°F/29.92 inches of Hg for gas flow calculations
Indoor/Outdoor Construction	Outdoor for REDACTED Indoor and Outdoor at White Bluff and Independence, with heat tracing on outdoor piping
Bulk Reagent Storage	30 days on-site

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ETR_00000746

Table 3-10. Operating Cost Criteria for Entergy Generating Stations

	Independence		White Bluff
Construction Labor ($/mhr)*	38	REDACTED	38
Operating Labor ($/mhr)*	30		30
Power ($/MWh)	34.03		34.03
Natural Gas ($/MMBtu)	5.35		5.35
Fuel Oil, ($/MMBtu)	7.17		7.07
Coal. ($/MMBtu)	1.42		1.27
Steam ($/1000 lbs)	3.50		3.50
Water ($/1000 gal)	0.22		0.22
Activated Carbon ($/ton)	1,000		1,000
Gypsum Sale Price ($/ton)	2		2
Anhydrous Ammonia Cost ($/ton)	225		225
Ammonium Sulfate Sale Price ($/ton)	100		100
Ash Disposal Cost (dry landfill only, $/ton)	2		2
Current Fly Ash Sale Price (average $/ton)**	4		4
Delivered Lime ($/ton)	70		70
Delivered Limestone ($/ton)	15		15
SO_2 Allowance Value - $/ton SO_2 removed	500		500
NOx Allowance Value - $/ton NOx removed	2500		2500

*Union plants in all cases

**Price and percentage of ash sold varies by season at some plants. Typically 80-90+% sold at each site. Price ranges from $3.5-7.35/ton. Therefore, will use an average value = $4/ton. Ash carbon content (0.6% LOI limit w/ 0.3-0.5% typical) is set by concrete specifications. Bottom ash is landfilled or ponded. Ash generated at Entergy plants typically meets the ASTM specification except sometimes during startup (incidents of high carbon content). A clay liner and cap is required in the latest permit modification. One cell = 7 acres, 6-8' deep = $500K.

Water Availability:

REDACTED

Independence – Only use one of two pumps for river water extraction. River use is restricted. Alluvial water has high calcium carbonate content; four process water wells and 2 potable water wells on site. Potable treatment includes chlorination and NaOH for pH control. No excess capacity exists at the water treatment plant.

White Bluff – May have to use river water for any additional makeup to control systems, and this water is likely to require treatment before it can be used for control system makeup. Ground water supply is currently tapped out. Potable water comes from off-site source.

Unit Outages:

REDACTED

White Bluff – Alternate Major (6-8 weeks) and Minor (3-4 weeks) every other year

Independence - Alternate Major (6-8 weeks) and Minor (3-4 weeks) every other year

Reagent Deliveries:

REDACTED or truck, and rail spurs may be available. Limestone delivered to site by truck to supply CFB boiler (owned by others).

White Bluff – Rail lines typically used all the time for coal deliveries (3 unit trains/week). No spur available for other reagent delivery and unloading.

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ETR_00000747

Independence – Rail lines typically used all the time for coal deliveries (3 unit trains/week). No spur available for other reagent delivery and unloading.

The emission allowances estimated for each of the Entergy coal-fired units are provided in Table 3-11. The values provided are on a per unit basis.

Table 3-11. Emissions Allowances for Entergy Coal-fired Units

Estimation of NOx Allowances Available	**Allowances/Year/Unit**
REDACTED	
White Bluff Allocation of NOx Allowances (2010)	8,648
White Bluff Allocation of NOx Allowances (2015)	7,206
ISES Allocation of NOx Allowances (2010)	9,670
ISES Allocation of NOx Allowances (2015)	8,058

Estimation of SO_2 Allowances Available	**Allowances/Year**
REDACTED	
Adjusted White Buff SO_2 Allowance Allocation 2010	21,588
Adjusted White Bluff SO_2 Allowance Allocation 2015	15,111
Adjusted ISES SO_2 Allowance Allocation 2010	17,133
Adjusted ISES SO_2 Allowance Allocation 2015	11,993

ICF Estimate of CO2 Allowance Cost; Carper with RPS

Year	$/ton
2010	14.24
2011	15.40
2012	16.65
2013	18.00
2014	19.47
2015	21.05
2016	22.78
2017	24.64
2018	26.66
2019	28.85
2020	31.21
2021	25.75
2022	21.25
2023	17.53
2024	14.47
2025	11.94
2026	12.18
2027	12.42

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ETR_00000748

4 PRELIMINARY EMISSIONS CONTROL PROCESS SCREENING

Entergy previously identified various commercial emissions control technologies that they wanted to have included in this study. The applicability of these systems was assessed by Washington Group and the results are summarized in this section. Additional technologies were selected during the process screening effort. Entergy also asked that the coal drying technology demonstrated by Great River Energy be added to the analysis.

4.1 Control Technologies Selected by Entergy

Control systems selected by Entergy to-date include

- SO_2 – Wet Limestone with Forced Oxidation (LSFO)
  - Lime Spray Dryer (LSD)
- NOx – Advanced Over Fire Air (OFA) - Mobotec
  - Selective Catalytic Reduction (SCR)
  - Selective Non-catalytic Reduction (SNCR)
  - Low NOx Burners (LNB) with Over-Fire Air (OFA)
- Hg – TOXECON I Activated Carbon Injection (ACI) with COHPAC (Compact Hybrid Particulate Collector)
  - TOXECON 1.5 – ACI with ESP Field Conversion to Fabric Filter (FF)
  - TOXECON II – ACI into the ESP Upstream of Last Field
- Coal Drying – Great River energy coal drying process – impacts on emissions

At this point, no other systems meet all the criteria established for the selection of viable systems. Most other developing technologies do not meet the requirement that they be commercially available and have been previously installed on large coal-fired utility boilers.

Washington Group previously assembled tabulations of the available control technologies for SO_2, NOx and mercury. These summary tables can be found in Appendix A. A series of Mandatory Criteria were applied to these processes to identify those systems that might be suitable for application to the Entergy units.

Emissions Control System Operating Characteristics – Table 4-1 provides the consumption rate for reagents, waste/byproduct production rates, power consumption, water consumption, etc. for the various emissions control systems as they might be applied at the three Entergy plants.

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ETR_00000749

Table 4-1. Operating Characteristics – Total for Each Plant Operating at 85% Average Load

SO_2 Control Options

Independence Plant

FGD Process/ % Removal	SO_2 Removed (tons/yr)	Chemicals (tons/yr)	Solid Product (tons/yr)	Water (gpm)	Power (kW)
LSFO/95%	47,500	88,700 limestone	142,000 gypsum	1820	19,900
LSD w/PJFF/92%	46,000	53,500 lime	118,000 mixed waste - $CaO/CaSO_3/CaSO_4$	1750	21,200
CFB w/ PJFF/92%	46,000	73,000 lime	148,000 mixed waste - $CaO/CaSO_3/CaSO_4$	1640	20,200

White Bluff Plant

FGD Process/ % Removal	SO_2 Removed (tons/yr)	Chemicals (tons/yr)	Solid Product (tons/yr)	Water (gpm)	Power (kW)
LSFO/95%	45,700	79,800 limestone	131,000 gypsum	1760	19,000
LSD w/PJFF/92%	44,300	51,500 lime	113,000 mixed waste - $CaO/CaSO_3/CaSO_4$	1750	20,700
CFB w/ PJFF/92%	44,300	70,200 lime	141,000 mixed waste - $CaO/CaSO_3/CaSO_4$	1660	19,700

REDACTED

NOx Control Options

Independence Plant

NOx Process/ % Removal	NOx Removed (tons/yr)	Chemicals (tons/yr)	Solid Product	Water (gpm)	Power (kW)
SCR/90%	16,350	6,000 ammonia	Spent Catalyst	None	4,900
SNCR/30%	5,450	9,200 ammonia	None	None	200
Mobotec/40%	7,270	None	None	None	14,000
LNB/OFA/55%	9,900	None	None	None	None

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ETR_00000750

Table 4-1 (continued). Operating Characteristics – Total for Each Plant Operating at 85% Average Load

NOx Control Options (continued)

White Bluff Plant

NOx Process/ % Removal	NOx Removed (tons/yr)	Chemicals (tons/yr)	Solid Product	Water (gpm)	Power (kW)
SCR/90%	28,800	9,900 ammonia	Spent Catalyst	None	5,000
SNCR/30%	8,900	11,700 ammonia	None	None	200
Mobotec/40%	11,900	None	None	None	13,900
LNB/OFA/55%	16,300	None	None	None	None

REDACTED

Hg Control Options

Independence Plant

Hg Process/ % Removal	Hg Removed (lbs/yr)	Chemicals (tons/yr)	Solid Product (tons/yr)	Water (gpm)	Power (kW)
Toxecon 1/90%	690	10,700 AC*	10,700 Spent AC*	None	8,400
Toxecon 1.5/90%	690	35,800 AC	35,800 Spent AC	None	8,800
Toxecon 2/90%	690	35,800 AC	35,800 Spent AC	None	400

White Bluff Plant

Hg Process/ % Removal	Hg Removed (lbs/yr)	Chemicals (tons/yr)	Solid Product (tons/yr)	Water (gpm)	Power (kW)
Toxecon 1/90%	930	10,500 AC*	10,500 Spent AC*	None	8,300
Toxecon 1.5/90%	930	35,000 AC	35,000 Spent AC	None	9,100
Toxecon 2/90%	930	35,000 AC	35,000 Spent AC	None	400

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ETR_00000751

Solid Products - The column providing the Solid Product stream in Table 4-1 above shows that total annual tons of reaction products generated by the various emissions control systems. For the LSD FGD process, the actual waste solids production rate will be lower than wet systems only if the reaction products are not mixed with the fly ash (new downstream particulate collector assumed for this evaluation to maintain fly ash sales). A mixed waste stream, containing all the reaction products, unreacted reagent and fly ash, would be 2-3 times the rate of the wet FGD processes. No market currently exists in the U.S. for the large volumes of the dry mixed waste that will be produced by a dry scrubbing system. The wet systems produce a gypsum waste (or byproduct) that contains minimal levels of fly ash.

Water Consumption by FGD Systems - Water consumption by the various technologies varies between technologies due to the differences in the flue gas conditions both entering and exiting the FGD absorber vessels. The dry and semi-dry technologies (CFB and LSD) only require that the flue gas temperature be reduced to within 35-40°F of the saturation point, resulting in less water lost to evaporation into the flue gas. The water content in the waste sent to the landfill will also vary between FGD systems. Water quality requirements also vary between systems. Lime slaking systems (required for CFB, LSD and wet lime processes) require a low dissolved solids concentration in the water fed to the hydration system to allow the lime hydration chemistry to produce primarily calcium hydroxide. No deionized water should be necessary for any of the FGD processes considered in this study. As a result, the total water consumed by each FGD system is expected to be 5-15% lower for the dry systems compared to the wet LSFO process.

Ash pond water has been reviewed in the past as a potential source of makeup for the FGD system. In previous projects, FGD suppliers found ash pond water to be acceptable as a makeup supply for both the lime (dilution water only) and limestone FGD systems. This included the grinding and dilution supply for the limestone wet ball mills. It was noted that the use of water sources that contain heavy metals leached from the fly ash over time could adversely affect FGD system performance, especially if the metals content changes over time. Aluminum oxide dissolved in the scrubber liquor can react with dissolved fluoride to form aluminum fluoride complexes that can coat limestone particles, making them unavailable for reaction with dissolved sulfite. This reduces the removal efficiency and increases the amount of limestone that must be fed to the system. Eventually, the system will no longer be able to meet its removal efficiency guarantee, and the system must be shocked with the addition of a large quantity of alkaline material (typically lime) to raise the pH, precipitating out the dissolved heavy metals. The metals concentration can also have a negative impact on the water treatment system if a blowdown stream is required from the FGD system to control the chloride concentration.

Previous studies have indicated that the use of this lower quality ash pond water may result in a small increase in the system capital cost. The analyses and quantities of the various water supplies available at the Entergy plants should be included in the specification issued for the purchase of any FGD system, or the modification plan for the existing system. Water consumption by the other emissions control processes should be minimal.

Power Consumption - Table 4-1 also provides the total system auxiliary power demand for each plant. The large motors associated with the FGD booster fans and recycle pumps will typically require 4160 V feeds, with the remainder fed from 480/220/110 V supplies. Therefore, the power required from the FGD equipment would be approximately 90% supplied by 4160 V feed, and 10% by the 480 V feed. The higher pressure drop for the combined dry scrubbing vessel (spray dryer or CFB/mechanical collector) and the downstream PJFF compared to the open spray

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ETR_00000752

tower in the wet LSFO system more than offsets the elimination of the large spray pumps. Therefore, the total power consumed by each FGD system was found to be within 10% of the alternate process auxiliary power requirement.

4.2 Review of Technology Selection

A large number of control technologies are available for each site. The number of alternatives can be reduced by first reviewing the technical requirements of each technology, comparing those to each unit's design and operating parameters, and evaluating performance in previous full-scale installations. In addition, a preliminary economic screening can be used to identify those technologies that cannot compete from a cost-effectiveness standpoint. Entergy has already completed a preliminary review of the available control technologies and selected the ones felt to be the most appropriate for installation on their coal-fired units. Washington Group reviewed these selections and compared them to the results of a preliminary process selection effort using a qualitative selection process.

The technical limitations, chemical requirements, waste disposal rates, and emissions control performance applicability for each of the technologies was provided in previous sections of this report. These operating characteristics are summarized again in Table 4-2. In each case, the proven reduction capability, boiler impacts, secondary fuel and chemical feed systems are identified along with system operating conditions that will impact the performance of the control system. Using the operating criteria summarized for each technology in Table 4-3, the applicability of each technology to Entergy units was determined.

Table 4-2. Emissions Control Technology Limitations and Performance

Pollutant Target/Process	Limitations	% Removal
NOx/Low NOx Burners	Can lead to high CO & LOI	20-35
NOx/LNBs with OFA	Can lead to high CO & LOI	30-60
NOx/Adv. OFA - Mobotec	Commercial experience currently limited to units less than 300 MW	25-50
NOx/SNCR	High NH_3 slip and low removal capability	20-30
NOx/SCR	High cost and SO_3 production	70-90
SO_2/LSFO	Large volumes of waste & high water consumption	95
SO_2/LSD	Higher lime consumption and large volume of waste	92
SO_2/CFB	Higher lime consumption and large volume of waste	92
Hg/TOXECON I	No long term demonstrations	50-90
Hg/TOXECON 1.5	Test facilities only	50-90
Hg/TOXECON II	Test facilities only	50-90

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ETR_00000753

Table 4-3. Control Technology Design Criteria

Control Technology Parameter	Design Criteria
LSFO Criteria	
Removal Efficiency	95%
Liquid to Gas Ratio	100 gallons/1000 acfm
Reagent Feed Rate	1.05 moles $CaCO_3$/mole SO_2 removed
LSD Criteria	
Removal Efficiency	92%
With or Without Recycle	Includes Recycle
Reagent Feed Rate	1.1 mole CaO/mole SO_2 inlet
CFB Criteria	
Removal Efficiency	92%
With or Without Recycle	Includes Recycle
Reagent Feed Rate	1.5 mole CaO/mole SO_2 inlet
SCR Criteria	
Removal Efficiency	90%
Ammonia Feed Rate	mole NH_3/mole of inlet NOx
Ammonia Slip	2 ppm
SO_2Oxidation	<2%
SNCR Criteria	
Removal Efficiency	30%
Ammonia Slip	10 ppm
Ammonia Feed Rate	mole NH_3/mole of inlet NOx
Mobotec Criteria	
Removal Efficiency	40%
ACI/TOXECON Criteria	
Carbon Feed Rate at 90% removal	3 lbs/MMacfm for clean gas 10 lbs/MM acfm for dirty gas
Target Removal Rates	90%

Washington Group completed a qualitative assessment of the emissions control processes that are best suited for pollutant control at each Entergy plant. This process selection was based on several 'mandatory' and 'desirable' screening criteria that were reviewed and modified based on input from Entergy staff. The control systems for consideration were chosen by first reducing the comprehensive listing of available control technologies (see Appendix A) to a group of viable process alternatives.

The applicability of different control technologies to the Entergy generating stations were evaluated using a method developed by Charles Kepner and Benjamin Tregoe (described in their book, The Rational Manager, by McGraw Hill Book Company c. 1965). This method of decision analysis used a systematic approach to make qualitative decisions:

- First, establish the objectives to be achieved
- Measure each of a number of alternatives against these objectives
- Finally, summarize the results

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ETR_00000754

The list of objectives is divided into two categories. Objectives that are required for each alternative or course of action (which, in this case, would be the control processes) are designated as 'mandatory' criteria. Each emissions control system is evaluated on a Go/No Go basis using these criteria. Objectives that express relative desirability, but are not mandatory are termed 'desirable' criteria; these characteristics are associated with relative advantages and disadvantages for each design. After the list of 'desirable' criteria is established, each item on the list is ranked and assigned a numerical weighting factor based on relative importance to the final process selection. Each alternative process is then assigned a score within a predetermined range for each of the 'desirable' criteria. These numerical scores depend upon the capability of the process to produce the desired results.

Multiplying the weighting factor by the assigned score for each criterion produces a weighted score for each of the 'desirable' process objectives. Adding all of the weighted scores for a specific process then produces the performance total for each control system design. As a result, the processes achieving the highest performance will be the most suitable for application at the Entergy coal-fired plants. The remainder of the study focused on the evaluation of the highest-ranking process options, including technical assessments, potential locations for installation of the control system equipment and capital/operating cost evaluations.

As a starting point, Washington Group proposed to use the following 'mandatory' and 'desirable' screening criteria for the selection of appropriate control technologies for Entergy:

(1) Commercially Proven and Currently Available

The process must be currently marketed by the process owner or licensor. The process must be commercially applied (or have been installed) on a 100+MW coal fired power plant in the U.S., Europe, or Japan.

(2) Compatible with Projected Fuel

(3) No Increase in Current Emission Limits

(4) Produces an Acceptable Waste or Marketable By-Product

(5) Reagent(s) Available at the Plant

One additional mandatory criteria was added to the NOx control technology assessment, that being the requirement that the process have the capability of reducing NOx emissions by some point in a range of 20-90%. The criteria for the mercury control systems only required the single issue of commercial availability to identify the one process (activated carbon injection) that is currently offered with process guarantees for coal-fired utility applications. These mandatory criteria have been applied to each of the processes identified (see tables in Appendix A). The Desirable Criteria and weighting factors established by Entergy for the process selection effort are tabulated in Table 4-4 for reference.

NO_x Reduction Technology Screening Criteria

NO_x Reduction Performance - Viable additional control technology shall be capable of a minimum 20% NO_x reduction. The NO_x reductions considered in this study shall be based upon existing or the forecasted emission levels.

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ETR_00000755

Status of Commercial Development - To pass the criteria for an acceptable level of commercial development, a process must be commercially viable and have been successfully proven on waste gas streams equivalent to that of a power generating facility of 100 MW (or more) for a period of at least one-year. The technology must be commercially available and actively marketed by a process vendor. Where only one supplier exists for a given process, the vendor shall be in sound financial condition for supporting guarantees and after market services.

Space Availability - Based upon the site walk downs, spatial constraints may be a factor in the selection process. A viable process must be constructed and maintained after commissioning within the confines of the existing facility. As a result, processes that cannot fit within the available space limitations may be discarded during the screening process.

FGD Process Compatibility - Additional NO_x reduction technologies must be compatible with back-end FGD systems. The NO_x control technology cannot adversely impact any sale of byproducts from the FGD system.

Equipment Compatibility - The NO_x Reduction technologies must be compatible with the existing boiler configurations and pulverizer maintenance considerations. In addition, the existing boiler configuration must provide sufficient residence time for reagent reactions to occur.

Qualitative Comparison of Control Technologies - Tables 4-4, 4-5, and 4-6 present the results of the Desirable Screening Criteria evaluations for the SO_2, NOx and mercury control system comparisons, respectively. The highest ratings were obtained by the LSFO system for SO_2 reduction, and the TOXECON 1 design for mercury control. TOXECON 1 was the favored system primarily based on the level of development of the process in comparison to the other two designs that have only completed limited testing. The NOx control systems are difficult to compare against one another because they have wide variations in their control efficiency capability. But based on the criteria established for this evaluation, the LNB/OFA system should be favored for application at each of the Entergy sites versus the other three options.

No assessment of the coal drying process is included in this section. Results of the economic analysis of this process as it could be applied to each of the Entergy coal-fired units can be found in Appendix D.

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ETR_00000756

Table 4-4. 'Desirable' Screening Analysis Summary for FGD Control Processes

Criteria	Weight	LSFO	LSD/FF	CFB/FF
Economic				
Capital Cost	10	8	5	5
Operating Cost	10	8	5	6
Reagent Availability	4	4	4	4
Generation Loss During Construction	5	5	5	5
Subtotal	29	25	19	20
Vendor Qualifications				
Number of Vendors	2	2	2	1
Technical Experience	3	3	3	2
Financial Stability	3	3	1	2
Process Guarantees	2	2	2	1
Subtotal	10	10	8	6
Process Performance				
System Availability & Reliability	8	7	6	7
Flexibility to Changes in Coal	5	5	3	4
Plugging/Scaling Potential	5	3	4	5
Erosion Potential	4	4	3	3
Corrosion Potential	4	2	4	4
Operation Simplicity	2	2	1	2
Turndown Capability	2	2	1	1
Subtotal	30	25	22	26
Process Design Features				
Level of Development	7	7	7	5
Space Required	7	4	4	5
Removal Efficiency Flexibility	4	4	2	3
Reheat Requirement	5	2	4	4
Subtotal	23	17	17	17
Environmental/Worker Risk				
Secondary Environmental Impacts	4	3	3	3
Low Safety Risk – High Temp./Press.	2	2	2	2
Low Safety Risk – Toxic Chemicals	2	2	1	1
Subtotal	8	7	6	6
TOTAL	100	84	72	75

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ETR_00000757

Table 4-5. 'Desirable' Screening Analysis Summary for NOx Control Processes

Criteria	Weight	LNB/OFA	Mobotec	SNCR	SCR
Economic					
Capital Cost	10	8	7	9	3
Operating Cost	10	9	7	8	4
Reagent Availability	4	4	4	3	3
Generation Loss During Construction	5	4	3	3	4
Subtotal	29	25	21	23	14
Vendor Qualifications					
Number of Vendors	2	2	0	1	2
Technical Experience	3	3	1	2	3
Financial Stability	3	3	2	2	2
Process Guarantees	2	2	2	1	2
Subtotal	10	10	5	6	9
Process Performance					
System Availability & Reliability	8	8	6	5	6
Flexibility to Changes in Coal	5	5	5	4	3
Plugging/Scaling Potential	5	5	5	3	3
Erosion Potential	4	4	3	4	3
Corrosion Potential	4	3	4	4	3
Operation Simplicity	2	2	2	0	1
Turndown Capability	2	2	1	0	1
Subtotal	30	29	26	20	20
Process Design Features					
Level of Development	7	7	4	5	5
Space Required	7	7	6	5	3
Removal Efficiency Flexibility	4	3	3	3	4
Reheat Requirement	5	5	5	5	5
Subtotal	23	22	18	18	17
Environmental/Worker Risk					
Secondary Environmental Impacts	4	4	4	2	2
Low Safety Risk – High Temp./Press.	2	1	1	1	0
Low Safety Risk – Toxic Chemicals	2	2	2	0	0
Subtotal	8	7	7	3	2
TOTAL	100	93	77	70	62

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ETR_00000758

Table 4-6. 'Desirable' Screening Analysis Summary for Mercury Control Processes

Criteria	Weight	TOX 1	TOX 1.5	TOX 2
Economic				
Capital Cost	10	5	5	9
Operating Cost	10	8	4	4
Reagent Availability	4	3	3	3
Generation Loss During Construction	5	5	3	4
Subtotal	29	21	16	21
Vendor Qualifications				
Number of Vendors	2	2	0	0
Technical Experience	3	2	0	1
Financial Stability	3	2	0	0
Process Guarantees	2	2	0	0
Subtotal	10	8	0	1
Process Performance				
System Availability & Reliability	8	8	6	7
Flexibility to Changes in Coal	5	5	5	4
Plugging/Scaling Potential	5	4	4	5
Erosion Potential	4	4	4	4
Corrosion Potential	4	4	4	4
Operation Simplicity	2	1	1	2
Turndown Capability	2	2	2	2
Subtotal	30	28	26	28
Process Design Features				
Level of Development	7	5	2	2
Space Required	7	5	6	6
Removal Efficiency Flexibility	4	4	4	3
Reheat Requirement	5	5	5	5
Subtotal	23	19	17	16
Environmental/Worker Risk				
Secondary Environmental Impacts	4	3	3	3
Low Safety Risk – High Temp./Press.	2	2	2	2
Low Safety Risk – Toxic Chemicals	2	2	2	2
Subtotal	8	7	7	7
TOTAL	100	83	66	73

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ETR_00000759

5 SYSTEM MODIFICATIONS BY PLANT AND UNIT

5.1 Fan Modifications

Based on the information obtained at each site that they are typically operating at the maximum capacity of their ID fans, it was assumed that new booster fans would be required at each site to overcome any added pressure drop imposed by applicable control system. Also, it was assumed that the existing boilers will be able to handle the additional pressure drop across the system without major structural modifications. This is a detailed design issue that can be addressed in more detail when cost estimates are refined in the future. Boiler implosion studies will be required in the future detailed design effort to confirm this preliminary assumption.

5.2 Structural Engineering Assessment

The following material summarizes the design basis for the conceptual engineering of the structural supports and foundations for the emissions control system retrofits. The major assumptions are also identified for reference.

1. All outdoor structures will be supported on piles.
2. Outdoor equipment installations are assumed.

Items that will be required during any future detailed design phase would include the following:

1. Detailed foundation investigation
   A. Prepare geotechnical investigation specification
   B. Investigate foundation for supporting the outdoor installations.
   C. Review existing building foundations.
2. Structural analysis for the adequacy of new structure and the existing building structure for the emissions control system retrofits. The evaluation of the existing building structure will be limited to the extent of the installation areas, not the entire building structure.
3. Evaluate the building structure including on-site investigation for the proposed ductwork routing.

5.3 Equipment Removal and Relocation

The installation of the emissions control systems may require the demolition and relocation of some components and structures at some plants. The current conceptual designs will not include sufficient detail to identify specific demolition or relocation requirements. Therefore, no allowance for the expected capital cost to accomplish these tasks will be included in the current retrofit cost estimates. Typical components requiring demolition or relocation could include:

- Heating, ventilating and air conditioning (HVAC) ductwork
- Electrical conduit
- Existing pipelines, both above and below ground
- Office and maintenance buildings
- Electrical duct banks
- Structural steel members may need to be relocated in some cases to make room for the equipment and ductwork

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ETR_00000760

- Some stairways, lighting and platforms may have to be relocated to maintain access to existing equipment.
- Continuous emission monitoring equipment may have to be relocated in some instances
- Existing instrumentation may need to be relocated to maintain access and measurement of operating conditions.

5.4 Electrical System Tie-ins

New MCC's are assumed to be necessary for each unit where additional motors are added for the emissions control systems. New auxiliary transformers may be required to handle the added electrical loads along with new switchgear and other electrical equipment. An allowance for the cost of electrical tie-ins equipment has been included in the cost estimates provided in this report.

5.5 Instrumentation and Controls Modifications

A separate DCS typically controls the operation of each emissions control system. Local controls and indicators track maintenance and operation functions. The DCS control functions include:

- Monitoring of process variables and equipment status
- Automatic sequencing and interlocks
- Alarms warning of operational failures

Inlet SO_2, NOx and O_2 concentrations must be monitored for most post combustion control systems. Measurements are on a dry basis for compatibility with the unit-specific CEMs and calculated flue gas flows, without need for moisture correction.

Process Instruments - Inlet flue gas temperature and flow is monitored for all emissions control equipment. The control system differential pressure is typically monitored to detect changes such as pluggage or physical damage. Reagent flow will be monitored in each case. A variety of other process parameters may be measured depending on the control system requirements (such as pH, slurry density, ammonia feed rate, activated carbon feed rate, etc.).

An allowance is included in the conceptual cost estimates to cover the cost of new instrumentation to support each emissions control system.

5.6 Boiler and Existing Flue Gas Path Impacts

The installation of the new emissions control equipment will in many cases increase the gas-side pressure drop of the system. New ID Booster fans will be necessary at each site that chooses to install new emissions control vessels such as fabric filters, wet scrubbers, lime spray dryers or SCR reactors. This added pressure drop and fans will increase the potential operating pressure transient that the boiler could see during a Master Fuel Trip. when and MFT occurs, The boiler fuel feed is shutdown, but the ID fans continue to pull the flue gas through the system. As a result, a large pressure reduction transient can occur in the boiler, sometimes exceeding the design conditions. In some cases, the negative pressure has been sufficient to cause structural damage to the boiler and other components of the flue gas train (ductwork, air heater, ESPs, etc.). The future detailed design of the emissions control retrofit should include a furnace pressure transient analysis to confirm that the boiler design can withstand the minimum pressure that could be seen during a MFT.

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ETR_00000761

The National Fire Protection Association issued NFPA 85 "Boiler and Combustion Systems Hazards Code (2004 Edition) states that system modifications should consider designs that will "minimize the risks of negative furnace draft in excess of the furnace structural capability." Two methods are provided:

- The furnace, ductwork, and associated equipment should be designed or modified to withstand the maximum head capability of the induced draft fan(s) system with ambient air.
- The furnace pressure control system shall be designed to minimize the potential for negative pressure transients beyond the structural capabilities of the furnace and other gas path components.

This code applies to all pulverized coal and circulating fluid bed boilers with a fuel input rating above 12.5 million Btu/hr, as well as for heat recovery steam generators. The code provides detailed direction for the design, installation, operation, maintenance and training for these types of units.

5.7 Impact on Existing Plant Operations

The installation and operation of emissions control equipment at the Entergy plants will have the following impacts on unit operations:

- The ACI/TOXECON retrofits onto these units will have minimal impact on normal day-to-day operation of the existing plant equipment. If required, the removal of mercury from the flue gas will be accomplished using a relatively independent dry injection and baghouse system. Gas will be diverted to this system using new I.D. booster fans. The impacts of TOXECON 1.5 and 2 designs may be more extensive since they will directly impact the current operation the existing cold-side ESPs at each unit due to injection of the AC into the last field of the ESP or converted field (to a FF).

- For the TOXECON 1 design, if the new equipment would become inoperable due to plugging of the bags or excessive solids dropout, then it could be isolated and the problem resolved while the units continued to operate. This is due to the fact that as currently envisioned, the existing particulate collection system would be left in operation and maintain the quality of the fly ash (not contaminated with carbon). If the alternate TOXECON designs experienced similar problems, then the operation of the plant would be directly impacted until the problem was resolved since there would be no way to bypass the equipment experiencing the problems.

- The one major issue that needs to be investigated during the detailed design of any emissions control equipment is the impact that the added pressure drop will have on the existing gas path, including the boiler, ductwork and the ESPs. The operation of the new booster fans can put added stress on the gas flow path during a master fuel trip. The boiler and gas path pressure transient could result in relatively high vacuum within the system. It is recommended that as part of any future detailed design, a pressure transient analysis be completed to determine any structural reinforcement requirements, or the need for upgraded instrumentation to allow quicker response to failures in the fuel supply system.

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ETR_00000762

- An additional set of fans will be operating in series with the existing I.D. fans in each case. Balancing the flow through the system at various loads will be a challenge that the plant staff will overcome during the startup of the new APC equipment and subsequent optimization of the modified flue gas system.

- Truck traffic will increase for delivery of the activated carbon, ammonia, or alkaline reagents, as well as for the removal of the spent carbon and waste solids generated by the FGD systems. The installation of the new equipment will also result in additional congestion for access to the other areas of the plant.

- For the FGD system, the relatively high feed rate for limestone or lime will require additional operator attention, in many cases requiring a new staff position to oversee the operation of the limestone or lime delivery and preparation equipment. One additional position may also be required for the LSFO gypsum dewatering and stack-out facility or to monitor the loading operation of the dry waste product produced by the lime spray dryer FGD system. In the gypsum case, a radial arm conveyor will continuously stack FGD product onto a concrete pad. Filling of trucks from this pile to transfer the material to the landfill will be primarily a daytime activity, requiring a front-end loader operator and truck drivers. Truck traffic around the site will also increase, due to reagent deliveries and transfer of the FGD product off-site. The cost estimates provided include the increased costs for operating labor in the fixed O&M costs.

- The new equipment may also impact the plant by occupying space that was previously used by plant staff for other activities such as outage laydown area, crane locations, general traffic through the plant, etc.

- Other impacts will include an increase in water consumption for the plant after startup of the FGD systems. Losses will include evaporation to the flue gas and losses with the waste product.

- In the case of SCR, the use of the ammonia solution will require additional safety training for the plant operating staff to make them aware of the potential hazards associated with handling of this toxic compound. If deliveries of aqueous ammonia (and limestone or lime) are accomplished by rail, then plant coal delivery traffic may have to consider the periodic rail deliveries of these materials and movement of the rail cars to the new or existing rail spurs.

- Lime would bring its own hazards due to its exothermic nature when it contacts water. Lime will release significant amounts of heat when water is added to the powdered solids, and if insufficient water is added steam can form. Commercial slaking systems (hydration systems to produce a lime hydroxide slurry) are designed to prevent the evolution of large quantities of steam. Contact of dry lime powder on skin can also cause burns, requiring additional plant personnel training on how to handle exposure to lime.

- Mortar specification sheets supplied by Entergy identify the mortar used in the construction of the REDACTED acid resistant brick stack liner. The composition indicates that the existing stack might be suitable for use downstream of a new FGD system. However, this issue would need to be addressed in more detail in any future

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ETR_00000763

detailed design effort for the retrofit of an FGD system onto the REDACTED . Further assessments of the existing stack liner condition, stack velocities, brick installation/roughness of the inner surface, and outage requirements would have to be completed before making a final decision regarding the reuse of hte existing stack.

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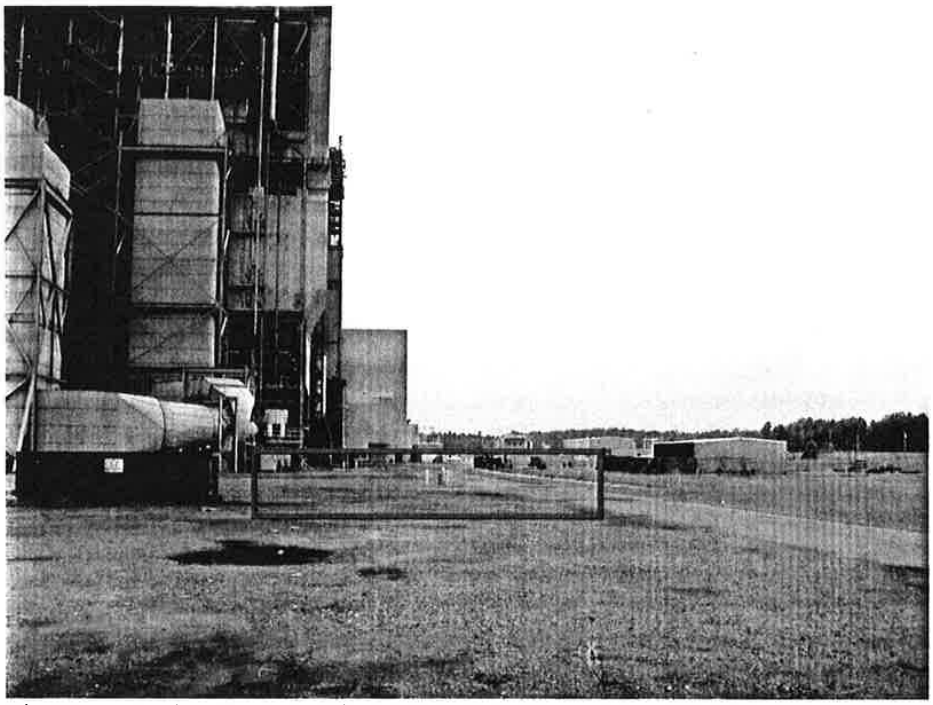
6 CONSTRUCTIBILITY ISSUES FOR EACH SITE

Hg emissions reduction at the Entergy plants can be accomplished with an Activated Carbon Injection and modifications to the existing particulate control equipment or the installation of a new COHPAC baghouse (see Figure 6-1 as one example of the location for TOXECON 1 at WB). These systems would incorporate the following major components:

- Ductwork
- COHPAC (Baghouse) or modifications to the existing ESP
- ID Booster Fans
- Carbon Injection including storage silo and injection equipment

Figure 6-1. Ground Location for Carbon Injection Equipment and COHPAC at White Bluff



The Hg removal equipment will be constructed at ground level near the point of injection to the greatest extent possible on each unit. The footprint for the Hg removal system will fit within area available at each site. The open area allows for flexible construction sequencing.

Site Access & Staging

Access to each site is good, but will require close coordination with plant operations personnel for use of the existing roadways and open areas. Adequate space should exist for a crawler-crane to set-up and move with the construction sequencing. Adjacent space also appears to be available for staging with good access to the construction area. An area of approximately 2 to 5 acres will be prepared for lay-down and possible on-site fabrication activities.

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Modularization Options

The open area for the equipment placement allows for modularization of various components. Modularization provides a significant benefit to emissions control projects in both cost and schedule, as it will reduce the amount of field labor and time to install the components. The amount of modularization that is possible will depend on the final design of the system, but the following represent areas for consideration:

- Ductwork – fabricated and shipped as "box" sections, pre-insulated
- Plenums – fabricated and shipped as "box" sections, pre-insulated
- COHPAC FF – fabricated and shipped in modules with internals installed, pre-insulated
- Activated Carbon Injection System – fabricating and shipping the storage silo as one unit and injection skids fully assembled ready for tie-in to utility and feed pipe connections.

Schedule

The Hg removal system installation will occur in two phases, Pre-outage and Outage. The following outlines these activities:

Pre-outage Activities:

- Foundations
- Structural
- ID Booster Fans
- COHPAC Fabric Filters
- Carbon Injection System
- Ductwork (up to the tie-in points)
- Insulation of Field Joints
- Electrical and I&C (up to the tie-in points)

Outage Activities:

- Demolition of Existing Plenums
- Installation of New Plenums and Discharge Ductwork
- Insulation of Demolition Areas and Complete Insulation of Field Joints
- Relocation of existing equipment and buildings that must be moved
- Tie-in of Mechanical, Electrical and I&C Systems
- Start-up and Check-out of Hg Removal system

After the outage the units will be brought back online to commission the TOXECON system. It should be noted that for this analysis, the conceptual designs assumed that the existing ash storage silos would be used to handle the solids collected by the various configurations of the particulate control equipment.

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ETR_00000766

Construction Approach:

After mobilization for the project, construction activities will begin in two areas. The first would be the area selected for installation of foundations, structural supports, booster fans, COHPAC FF, carbon injection and ductwork. Impacts to the construction approach are as follows:

- Demolition/Relocation – Many relocations and demolition activities will require a plant outage, and they will be time-critical and pre-outage planning and construction must ensure minimal demolition and relocation durations.
- Civil – No significant concerns for foundation installation are anticipated. However, underground interferences are a possibility and the construction approach utilized will depend on the interferences encountered.
- Structural/Mechanical – The installation of structural and mechanical components for the Hg removal system should not present any significant impacts for the various Entergy plant operations.
- Electrical – The most significant challenge with the electrical installation will be to incorporate the new service with the existing systems. A new transformer, switchgear and motor control centers will need to be incorporated for installation of the Hg removal system. Historically, location of the gear and tie-ins are problematic for the electrical installation. Electrical bulks and gear located at the equipment will need to be coordinated with the structural/mechanical activities.

Summary

Based on the preliminary investigation completed to-date, construction of the Hg removal system is feasible at each site. Construction activities that will require more investigation to finalize a detailed approach to the installation of this system are:

- Underground interferences need to be investigated for final layout of equipment foundations.
- Impacts of the relocation of existing equipment must be identified. Further investigation will be needed to determine if a special outage is needed.
- Ductwork removals will require more investigation to determine specific sequencing for their demolition.
- Ductwork installation will require more investigation to determine crane access and possible rearrangement or relocation of existing equipment.

Retrofit of NOx Control and FGD Systems

Figures 6-2 through 6-11 provide examples of the location options that might be considered at the three sites for the NOx and SO_2 control equipment. The retrofit of NOx and SO_2 removal equipment may include the following major systems:

- Selective Catalytic Reduction (SCR) with Anhydrous Ammonia
- Flue Gas Desulfurization (FGD) - Note: Both dry and wet FGD systems are addressed in this study. Since the approach to construction is similar for both, only the wet system is discussed in this section representing the worst case
- Lime or Limestone Unloading, Reclaim and Preparation Facilities
- Waste Dewatering Facilities

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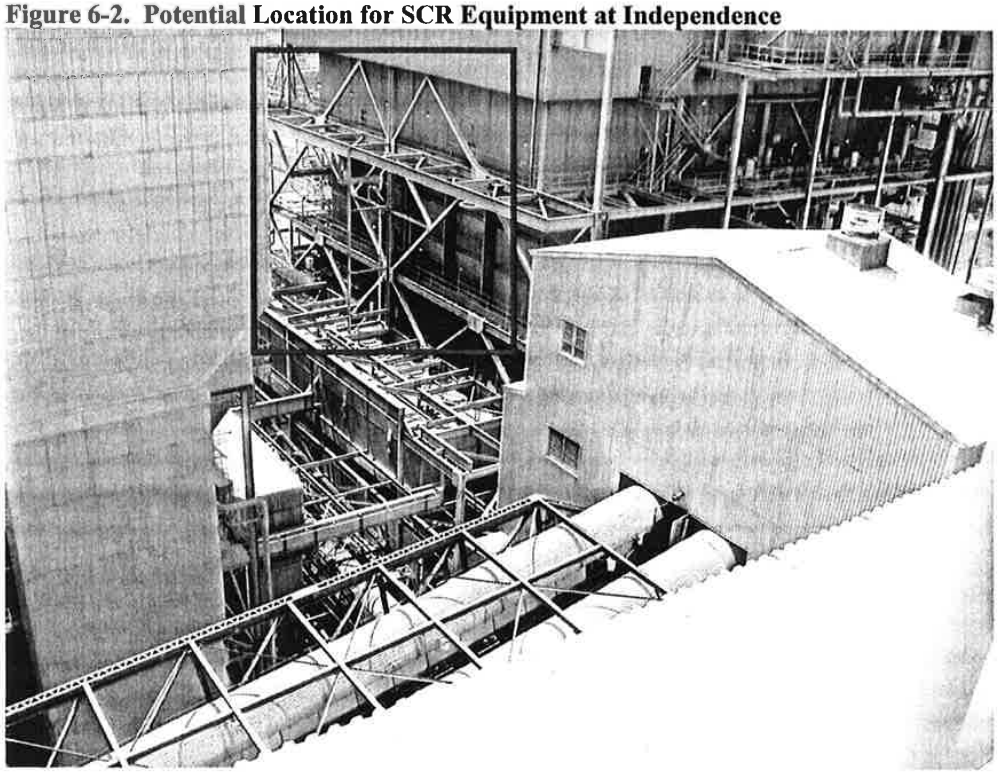
ETR_00000767

- Ductwork
- New chimney if required.

The NOx control and FGD equipment typically will be constructed in unoccupied areas located as close as possible to the existing plant. The intent in this construction approach is to demolish the structures, but utilize the existing support steel to the maximum extent possible. As this project is refined and more investigation and design is completed, portions of the structure may be salvaged for use with the NOx control or FGD systems.

Figure 6-2. Potential Location for SCR Equipment at Independence



The lime or limestone delivery, storage and preparation subsystem, as well as the waste sludge dewatering and stack-out area, will be constructed in open areas typically remote from the existing plant (see Figure 6-7 and 6-8). For a wet LSFO system, the limestone preparation area and the waste dewatering/stack-out pad will be constructed in the same area at each site, and the limestone unloading/stack and reclaim will be constructed farther away from the stack. Both areas have no encumbrances except for existing power lines that will need to be addressed in the final design and planning.

Modularization Options for FGD and NOx Control Systems

The open areas surrounding each plant provide an opportunity to modularize various components. Modularization provides a significant benefit to the project in both cost and

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Figure 6-3. Potential Location for FGD Equipment at White Bluff

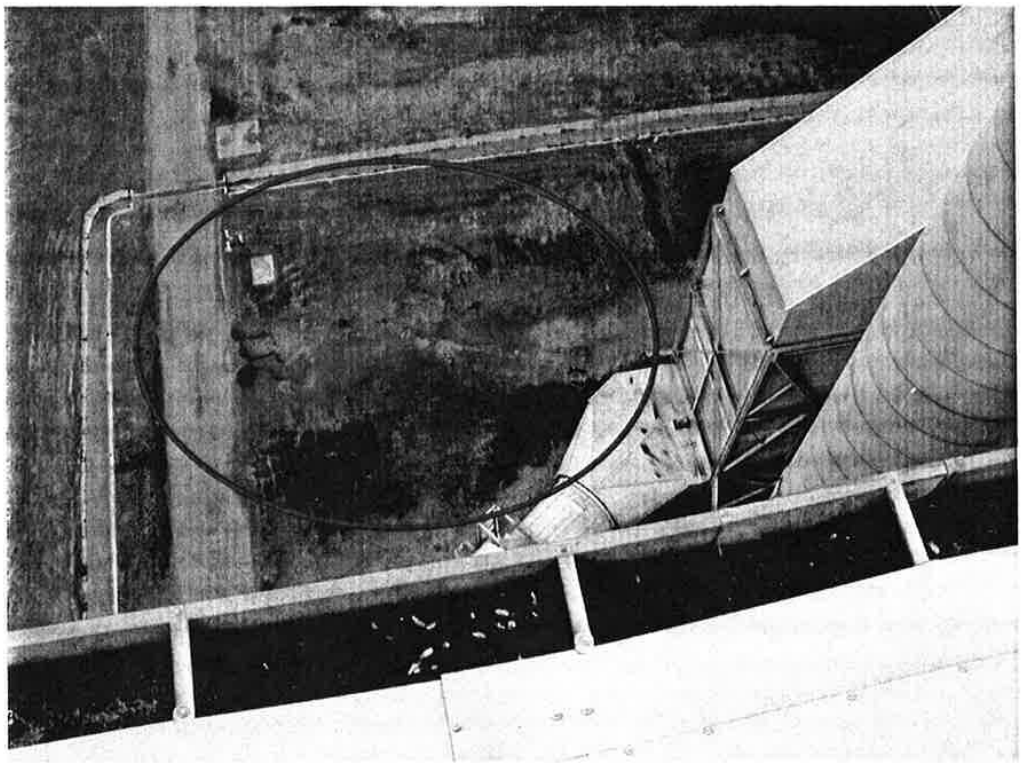
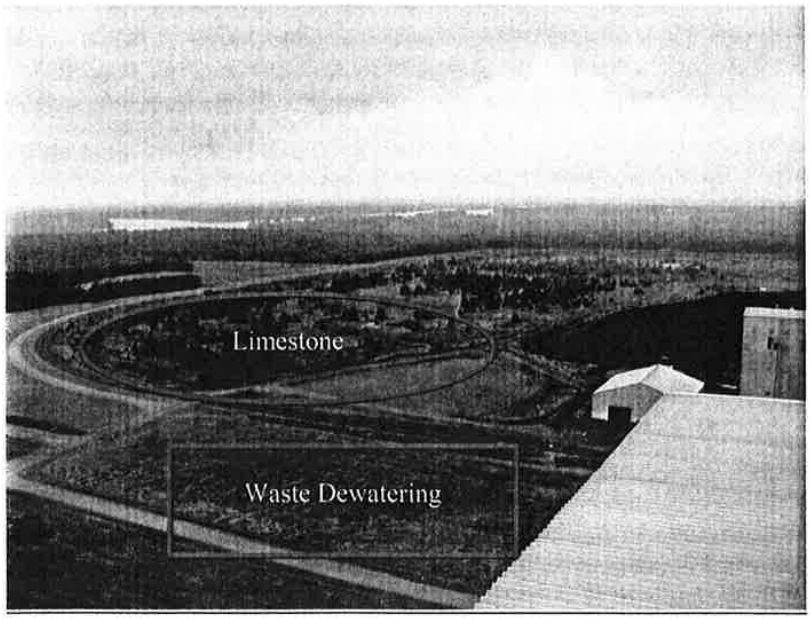


Figure 6-4. Location of Lime/Limestone Prep Area & Waste Dewatering at White Bluff



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schedule, since it will reduce the amount of field labor and time to install the components. Modularization also reduces the amount of scaffolding required by a project, which can represent 15 to 20% of the installation man-hours. The amount of modularization possible will depend on the final design of the system, but the following subsystems might benefit from off-site assembly of modules:

- Ductwork – fabricated and shipped as "box" sections, pre-insulated
- SCR – fabricated and shipped as layers, pre-insulated
- Ammonia Injection Skids – fabricated off-site, pre-piped and pre-wired
- FGD – absorber vessels fabricated and shipped in ring sections with internals installed
- Conveyors – fabricated and shipped in "box" sections with completed galleries

Since delivery of equipment and materials will be by truck or rail, the limitations for shop modularization would be the "over-the-road" and rail considerations, but adequate space is available to further modularize shop components on site to limit crane lifts and field installation man-hours.

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Access & Staging for FGD and NOx Control Systems

Access to each site is good, but existing equipment may impact the methods utilized and the overall cost of construction:

- If large open areas are available for lay down and staging, the SCR, FGD and ductwork components installed at each site could be constructed in large modules and set with limited crane lifts that will reduce field installation man-hours and the construction duration.
- If the area near the construction site is limited, then it may be necessary to move only smaller components; modularization to some extent would still be feasible.
- The existing coal conveyors will have some impact on site access and component installation, but enough room exists to set large sections of the SCR and FGD absorber vessels.
- The areas planned for the limestone and gypsum systems have good access and construction activities will have no impacts on plant operations.

Abundant area for staging is available and each construction location has ample space to stage, fabricate and construct the required components.

Schedule

The installation of NOx and SO_2 removal equipment will occur in two phases, Pre-outage and Outage. The following pre-outage activities will be constructed in three areas and can be done concurrently or consecutively depending on the project schedule:

SCR/FGD Area

- Demolition
- Foundations
- Structural supports
- SCR box
- Anhydrous ammonia system
- FGD absorber
- Ductwork, by-pass and transitions (up to the tie-in points)
- Mechanical equipment (spray pumps and oxidation compressors)
- Piping (up to tie-in points)
- Electrical and I&C (up to the tie-in points)
- Insulation of field joints

Lime or Limestone Prep & Waste Dewatering Area

- Foundations
- Structural supports
- Buildings
- Process water storage tank/reagent slurry tank
- Lime or limestone day bin
- Ball mills or slakers
- Hydroclone system (pumps and tanks)
- Vacuum belt or rotary drum filter system

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000771

- Waste transfer and storage system w/ stack out conveyor
- Piping
- Electrical and I&C

Lime or Limestone Unloading/Reclaim Area:

- Railroad spur
- Foundations and pit
- Structural supports
- Buildings
- Silos or hoppers, feeders, dust control
- Transfer conveyors
- Piping
- Electrical and I&C

Outage Activities

- Demolition of ductwork
- Installation of SCR/FGD ductwork tie-ins and isolation dampers
- Air preheater modifications
- Insulation of demolition areas and complete insulation of field joints
- Tie-in of mechanical, electrical and I&C systems
- Start-up and check-out of NOx and SO_2 removal systems

After the outage, the units will be brought back online to commission the systems. It should be noted that for this analysis, the conceptual designs assumed that the existing ash storage silos would be used to handle the solids generated by the particulate collection equipment.

Construction Approach for NOx and SO_2 Control Systems

After mobilizing for the equipment installation, construction activities will begin in at least two areas and depending on the project schedule, possibly three. Standard construction techniques would be employed for the retrofit. These techniques are discussed as follows:

- Demolition - Cost estimates to cover the expenses associated with the demolition of existing structures would be developed during the detailed design of the control NOx control and FGD absorbers.
- Civil – Techniques employed for foundation installations and rail spur construction will be schedule driven with the intent to have construction occur anytime during the year. Should concrete work fall in the winter, sprung structures or protection may be used.
- Architectural/Buildings – Following the foundation work, buildings are also schedule driven to have areas enclosed for construction activities to continue during the winter.
- Structural – It is anticipated that the structural support salvaged from demolition will be incorporated into the support structure for the SCR and associated ductwork for the SCR and FGD. The existing steel may require reinforcing or interconnection modifications to accommodate the required loading and equipment layout. The remaining structural steel will be erected, plumbed, and bolted utilizing standard practice. Grating and platforms will be integrated with the steel erection to minimize need for scaffolding.
- SCR – The SCR would be shop fabricated in sections and shipped by truck or rail to the site. On site those sections would modularized in a fabrication area to minimize the number of crane lifts and to reduce the amount of erection joints required. The

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ETR_00000772

hopper/outlet section would be set first, followed by the "box" (catalyst layers) section, and then the hood/inlet section would be set.

- Absorber Vessel – The absorber vessel would be shop fabricated in segments and shipped by truck or rail to the site. On site those segments would be modularized into ring sections complete with the internals as required. Depending on weight of the rings and placement of the crane, ring sections would be stacked and joined to the maximum extent possible.
- Air Preheater – For SCR retrofits, modifications required might include basket replacement, rework of basket supports on the rotors and replacement of seals. The existing access and maintenance doors will be utilized to perform these activities.
- Ductwork – The ductwork will be shop fabricated in "box" sections complete with internal support and insulation. On site, the framing portions of the expansion joints as well as the dampers will be installed on the duct prior to rigging into place. Ductwork will be installed in both the pre-outage and outage phases of the project.
- Conveyors – Stringers will be shipped as completed galleries in 40' sections to be installed on the structural bents. Remaining work would be to install belting and align idlers and pulleys.
- Mechanical Equipment – The equipment received for the NOx control components, FGD, and Lime or Limestone/Gypsum systems will be skid mounted ready for installation on their foundations. Few components would require any pre-assembly.
- Piping – These systems will have large bore pipe shop fabricated in spools to the maximum extent possible. Small-bore piping will be field run; however, areas that have repetitive configurations also lend themselves to shop fabrication.
- Electrical – The most significant challenge with the electrical installation will be to incorporate the new service with the existing systems. A new transformer, motor control centers, and switchgear will need to be installed to support the operation of the new equipment. Historically, location of the gear and tie-ins are problematic for the electrical installation. Electrical bulks and gear located at the equipment will need to be coordinated with the structural/mechanical activities.

Summary

Based on this preliminary investigation, retrofit of NOx, SO_2 and Hg removal is feasible. Construction activities that will require more investigation to finalize an approach are the following:

- Final layout of the SCR and FGD will determine what if any portion of any unoccupied structures will be salvaged.
- Underground interferences need to be investigated for final layout of equipment foundations.
- Overhead power lines will need to be addressed in final design and construction plans.
- Piping from the Limestone Prep Building to the Absorber area are likely to traverse a roadway, either overhead or underground.
- Conveyors from the Limestone Stack to the Limestone Preparation Building are likely to traverse a roadway; hence, clearances need to be considered.
- Retrofit activities will need to be integrated with normal outage activities. Resources could be combined for both projects.
- The layout of process equipment has not been finalized. During the detailed design phase of a future project, the positioning of the vessels and ductwork will determine ductwork requirements.

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ETR_00000773

- As part of the detailed design effort, the location of the new lime or limestone unloading area should be coordinated with the location of the existing track. It may also be feasible and cost effective to combine the reagent unloading and storage facilities, as well as the waste handling systems, for the FGD systems.

Figure 6-6. Ground Location for Carbon Injection Equipment and COHPAC at Independence

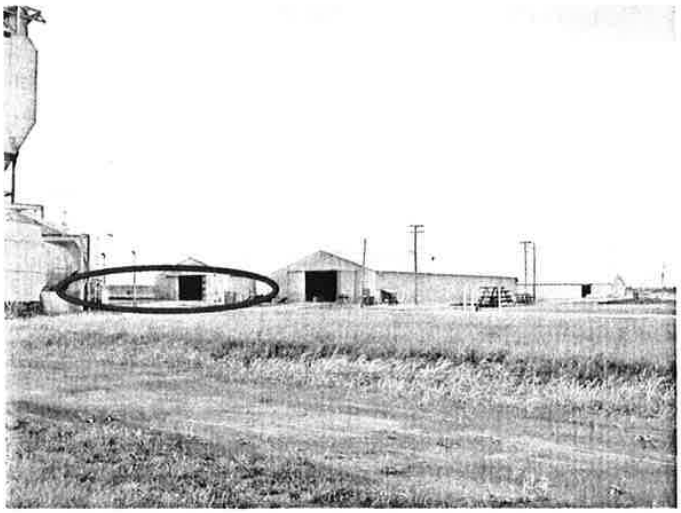

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Figure 6-7. Potential Location for SCR Equipment at White Bluff

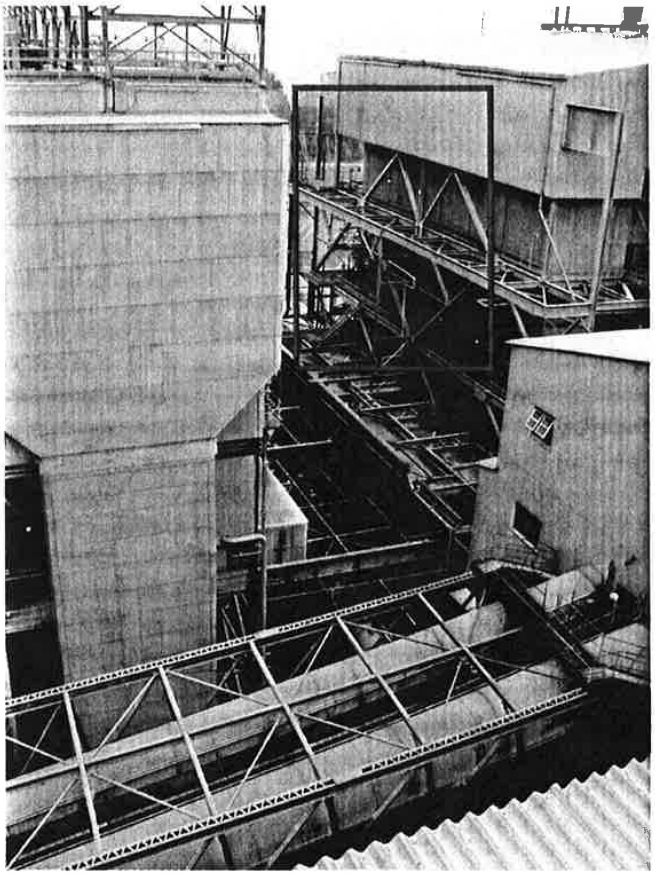

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Figure 6-8. Potential Location for FGD Equipment at Independence

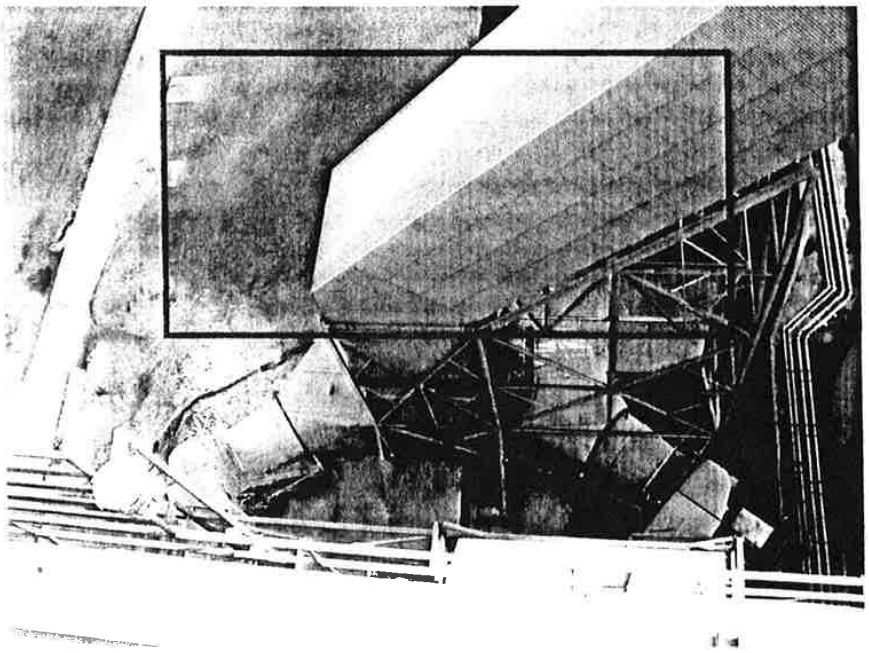

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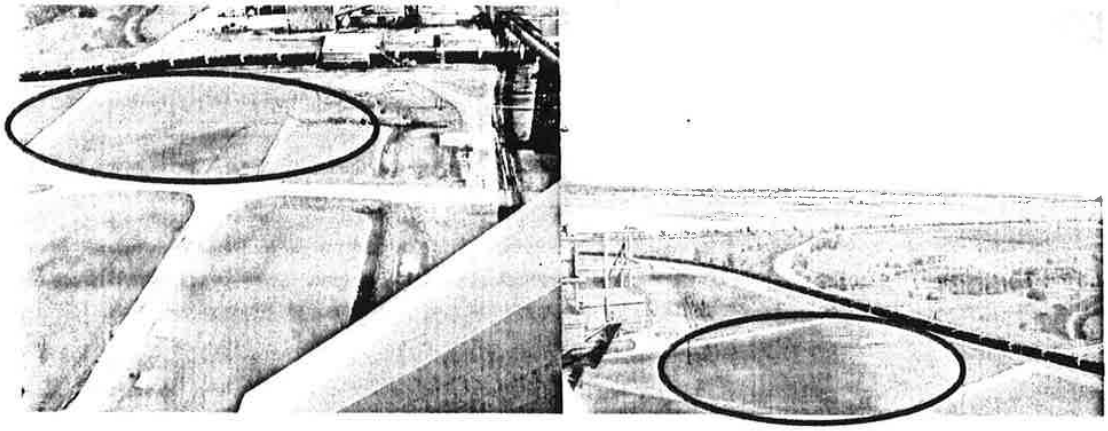
Figure 6-10. Potential Locations of Lime/Limestone Prep Area & Waste Dewatering at Independence



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ETR_00000777

7 EMISSIONS CONTROL SYSTEM ECONOMIC ANALYSES

The technical evaluations on control system alternatives described in the previous sections identified the emissions control system alternatives that would be potentially viable at the various Entergy sites based on the limited design information currently available. Final selection of the retrofit technologies for each of these units then becomes an economic choice, taking into account the outage cost penalty associated with each option and its evaluated capital and operating costs. These cost components were used to calculate the Present Worth of Revenue Requirement (PWRR) for each alternative, leading to the identification of the lowest cost option for each plant in terms of cost per ton or pound of pollutant removed.

The selected technologies can achieve the necessary removal efficiencies at the design flue gas conditions for each facility. The following material describes the capital cost estimating process, including critical design and economic assumptions. The economic criteria used for these analyses were summarized in Section 3.6.

7.1 Capital Cost Basis for Control Equipment

The capital cost estimates include all capital expenditures associated with the control system retrofits. The capital costs were estimated using the following methodology:

- Equipment quotations were obtained from historical data.
- Conceptual designs served as the basis for cost estimates. Structural steel, concrete, instruments and controls, piping, electrical, etc. are all included in the installed cost estimates as part of the historical installation factors that have been previously developed in-house.
- Installation costs also include historical factors for labor and materials in each case.
- Home office/Engineering expenditures by Entergy are included in the current estimates at 10% of the estimated installed capital cost.
- Entergy noted that in Arkansas and Louisiana, no sales tax would be incurred for the installation of emissions control equipment at their plants.

The methodology and components included in these conceptual cost estimates are summarized in the Estimate Basis provided in Appendix B of this report. These cost estimates include the cost of equipment components as well as the cost to install these components, including modifications, but do not include costs for relocation and demolition (if any) of existing structures. At this point, no unit outage penalty was included in the capital cost estimates for installation of the new emissions control equipment. It was assumed that the tie-ins of ductwork and piping to existing systems could be accomplished during normal scheduled plant outages.

The capital cost for each emissions control system is built up from a variety of components and subsystems. The major equipment included in each estimate are listed in Appendix D. The items included in these cost estimates are outlined below:

- Reagent Feed System
- Emissions Control System
- Flue Gas System
- Byproduct Handling System (where applicable)

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ETR_00000778

- Solids/Waste Handling System
- General Support Equipment
- Miscellaneous Support Equipment

Since these will not be new installations, the costs to install equipment are expected to be higher for a retrofit than for a new plant installation. This increase is due primarily to the presence of existing structures and underground obstructions, as well as reduced productivity due to limitations on construction equipment access. A general retrofit factor of 30% was added to the capital cost estimates to account for these retrofit interferences and variations from a new plant installation.

It should be noted that the cost estimates that are provided herein are dependent upon the various underlying assumptions, inclusions and exclusions utilized in developing them. Actual project costs will differ, and can be significantly affected by factors such as changes in the external environment, the manner in which the project is implemented, and other factors which impact the estimate basis or otherwise affect the project. Estimate accuracy ranges are only for projections based upon cost estimating methods and are not a guarantee of actual project costs.

Table 6-1 provides a summary of the capital and operating cost estimates developed for each control technology at each plant. More details of the components of these estimates can be found in Appendix D.

7.2 Operating and Maintenance Costs Basis

The O&M cost estimates include all operating costs associated with the APC system retrofits. The total O&M costs include fixed O&M costs, variable O&M costs, and fixed charges. These cost estimates are presented in $/year and in levelized cost per ton of SO_2 or NOx removed (or in pounds per year in the case of mercury). The costs are broken down as follows:

Fixed O&M costs are based on:

- Number of operators x operator labor rate = Operating labor cost
- Maintenance costs (40% labor and 60% materials cost) calculated as a percentage of the installed capital cost (Total Plant Cost). Maintenance cost percentage varies depending upon the materials being handled in each subsystem – ranging from 1% for gases to 8% for abrasive solids.
- Administrative support labor as a percentage of the operating and maintenance labor cost

Variable O&M costs are based on:

- Reagent costs
- Disposal cost for landfill of waste produced by emissions control systems
- SO_2 and NOx allowance credits
- Steam costs
- Water cost – fresh and blowdown
- Additional power costs

The fixed charge rate is a function of the total capital requirement and is based on the first year fixed charge rate. The Fixed Charge is meant to account for the cost of the capital investment distributed over the operating life of the emissions control equipment. Usage rates for chemicals and utilities were provided in Section 4.

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ETR_00000779

7.3 Equipment Sparing Philosophy

For the conceptual design, Washington Group assumed that each unit would require a separate absorber module or large reactor vessel capable of handling the full gas flow from only one unit. No spare modules are included in the conceptual design due to the 99%+ reliability guarantees that can be obtained from emissions control vendors. However, Washington Group has included spare components for the rotating equipment, including the recycle slurry pumps feeding slurry to the absorber modules.

Installed spares are also included in the cost estimates for the ACI and SCR system critical components. The COHPAC PJFF includes only spare compartments to allow on-line cleaning. The SCR system does not include a spare reactor vessel, but does include additional volume for the installation of an extra level of catalyst when needed.

7.4 Results of Economic Analysis

Tables 7-1 through 7-5 summarize the results of the capital and operating cost evaluations for each unit. Capital costs are presented in both total dollars and in $/kW. The O&M costs are summarized in these tables as the levelized cost per ton of pollutant removed so that direct comparisons are possible between systems achieving different removal efficiencies.

Table 7-1. Cost Estimates for Emissions Control Equipment at Independence Unit 1

Process	Capital Cost (million $)	Capital Cost ($/kW)	Levelized Cost* ($/ton or lb. removed)
FGD Systems			
LSFO	$79	$94	$500/ton SO_2
Lime Spray Dryer (with PJFF)	$124	$148	$800/ton SO_2
Circulating Fluid Bed (with PJFF)	$107	$128	$700/ton SO_2
NOx Control System			
SCR	$78	$94	$2,300/ton NOx
SNCR	$8.6	$10	$900/ton NOx
Mobotec	$14.6	$17	$1,100/ton NOx
LNB with OFA	$21	$25	$600/ton NOx
Hg Control Systems			
TOXECON 1	$36.4	$44	$36,000/lb Hg
TOXECON 1.5	$34.9	$42	$74,000/lb Hg
TOXECON 2	$10.6	$13	$61,000/lb Hg

*Levelized costs include a credit for the SO_2 allowances generated. IN1 = 16,910/year for LSFO and 16,160/year for dry scrubbing systems starting in 2008. Sold for $500/allowance.

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ETR_00000780

Table 7-2. Cost Estimates for Emissions Control Equipment at Independence Unit 2

Process	Capital Cost (million $)	Capital Cost ($/kW)	Levelized Cost ($/ton or lb. removed)
FGD Systems			
LSFO	$81	$96	$510/ton SO_2
Lime Spray Dryer (with PJFF)	$127	$151	$810/ton SO_2
Circulating Fluid Bed (with PJFF)	$110	$130	$710/ton SO_2
NOx Control System			
SCR	$78	$92	$2,000/ton NOx
SNCR	$8.7	$10	$800/ton NOx
Mobotec	$14.6	$17	$960/ton NOx
LNB with OFA	$21	$25	$520/ton NOx
Hg Control Systems			
TOXECON 1	$38	$45	$37,000/lb Hg
TOXECON 1.5	$36	$42	$77,000/lb Hg
TOXECON 2	$11	$13	$63,000/lb Hg

*Levelized costs include a credit for the SO_2 allowances generated. IN2 = 17,150/year for LSFO and 16,400/year for dry scrubbing systems starting in 2008. Sold for $500/allowance.

Table 7-3. Cost Estimates for Emissions Control Equipment at White Bluff Unit 1

Process	Capital Cost (million $)	Capital Cost ($/kW)	Levelized Cost* ($/ton or lb. removed)
FGD Systems			
LSFO	$78	$95	$420/ton SO_2
Lime Spray Dryer (with PJFF)	$123	$151	$740/ton SO_2
Circulating Fluid Bed (with PJFF)	$106	$131	$640/ton SO_2
NOx Control System			
SCR	$77	$94	$1,300/ton NOx
SNCR	$8.7	$11	$590/ton NOx
Mobotec	$14.4	$18	$610/ton NOx
LNB with OFA	$20.5	$25	$340/ton NOx
Hg Control Systems			
TOXECON 1	$36.5	$45	$27,000/lb Hg
TOXECON 1.5	$34.4	$42	$55,000/lb Hg
TOXECON 2	$10.6	$13	$45,000/lb Hg

*Levelized costs include a credit for the SO_2 allowances generated. WB1 = 19,750/year for LSFO and 19,030/year for dry scrubbing systems starting in 2008. Sold for $500/allowance.

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ETR_00000781

Table 7-4. Cost Estimates for Emissions Control Equipment at White Bluff Unit 2

Process	Capital Cost (million $)	Capital Cost ($/kW)	Levelized Cost ($/ton or lb. removed)
FGD Systems			
LSFO	$78	$92	$350/ton SO_2
Lime Spray Dryer (with PJFF)	$124	$147	$670/ton SO_2
Circulating Fluid Bed (with PJFF)	$107	$127	$560/ton SO_2
NOx Control System			
SCR	$77	$91	$1300/ton NOx
SNCR	$8.8	$10	$590/ton NOx
Mobotec	$14.6	$17	$620/ton NOx
LNB with OFA	$21	$25	$340/ton NOx
Hg Control Systems			
TOXECON 1	$37	$44	$27,000/lb Hg
TOXECON 1.5	$35	$42	$55,000/lb Hg
TOXECON 2	$11	$13	$45,000/lb Hg

*Levelized costs include a credit for the SO_2 allowances generated. WB2 = 22,690/year for LSFO and 21,960/year for dry scrubbing systems starting in 2008. Sold for $500/allowance.

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ETR_00000782

7.5 Sensitivity Analyses and Alternate Scenarios

The previous cost results directly compared the LSD/FF with LSFO for SO_2 control independent of the reduction of mercury. The following material provides additional scenarios with various combinations of control technologies addressing multiple pollutants with integrated systems. In addition, cost sensitivity analyses are provided for the variation of the levelized cost with changes in design and operating parameters for the emissions control systems.

Breakdown of Fabric Filter Costs by Unit

Table 7-6 presents a cost summary for the LSD process as it would apply to each unit. In this table, the costs for the PJFF have been broken out so that the cost for the standalone LSD system can be identified. In each case, the cost of the fabric filter is expected to be $50-55/kW for each Entergy installation.

Table 7-6. LSD and FF Cost Breakdown for All Entergy Coal-fired Units

Process	Capital Cost (million $)	Capital Cost ($/kW)
Independence 1		
Lime Spray Dryer	$80.3	$96
Pulse Jet Fabric Filter	$43.6	$52
Independence 2		
Lime Spray Dryer	$81.5	$97
Pulse Jet Fabric Filter	$45.4	$54
White Bluff 1		
Lime Spray Dryer	$79.3	$97
Pulse Jet Fabric Filter	$43.6	$54
White Bluff 2		
Lime Spray Dryer	$80.1	$97
Pulse Jet Fabric Filter	$44.2	$54

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FGD Control Cost Without Allowance Credits – The number of allowances generated by the Entergy coal-fired boilers after the FGD retrofits will be tens of thousands of tons per year. And with the current SO_2 allowance value now above $500/ton and expected to rise over the next few years, the impact of the credit for the SO_2 allowances is significant. However, individual state legislation may limit the ability of Entergy to sell these allowances outside the Entergy system or outside the state where the plants are located. Therefore, each plant may not be able to realize the full credit that would be possible if the allowances were sold on the open market. Table 7-7 provides the cost estimates for each FGD system without taking any credit for allowance generation.

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ETR_00000783

Table 7-7. FGD Cost Estimates Without SO_2 Allowance Credits

Process	Capital Cost (million $)	Capital Cost ($/kW)	Levelized Cost ($/ton SO_2 removed)
Independence 1			
Wet LSFO	$79.5	$95	$921
LSD with PJFF	$124	$149	$1215
CFB with PJFF	$108	$129	$1116
Independence 2			
Wet LSFO	$81.6	$97	$939
LSD with PJFF	$128	$152	$1239
CFB with PJFF	$111	$131	$1139
White Bluff 1			
Wet LSFO	$78.5	$96	$941
LSD with PJFF	$124	$152	$1260
CFB with PJFF	$107	$132	$1157
White Bluff 2			
Wet LSFO	$78.9	$94	$936
LSD with PJFF	$125	$149	$1253
CFB with PJFF	$108	$128	$1149

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Cost Sensitivity Analyses

Cost sensitivity analyses were run for a variety of parameters to identify those design and operating assumptions that had major impacts on the emissions control system cost analyses:

- % Removal
- Unit Size (example)
- Reagent Stoichiometry/Feed Rate
- Coal Sulfur Content
- Activated Carbon Price for Hg Control

Figures 7-1 through 7-5 provides the result of these sensitivity analyses. A breakdown of the components of the levelized operating cost will also be provided in Appendix D so that the contribution of various consumables, fixed operating costs (labor, etc.) and the fixed capital charges can be compared to one another.

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ETR_00000784

Figure 7-1. Levelized Cost Sensitivity to Variations in SO_2 Removal Efficiency – White Bluff

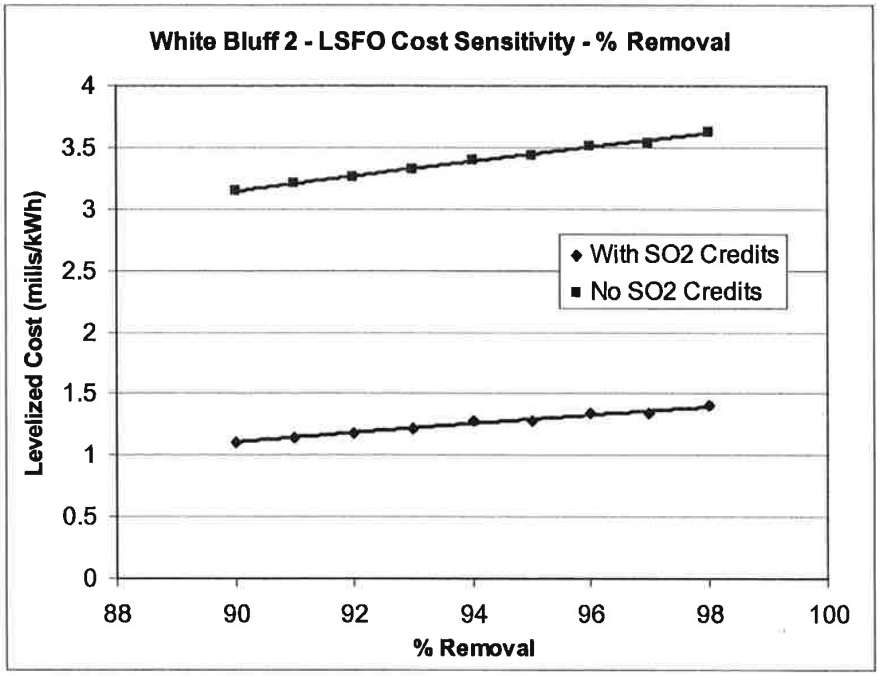
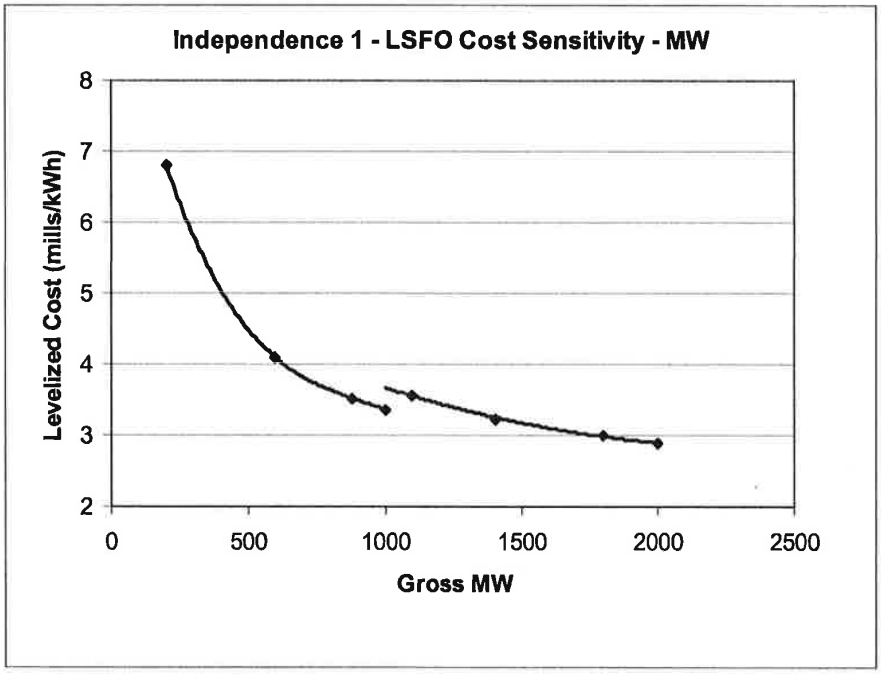


Figure 7-2. FGD System Cost Sensitivity to Unit Size – Example Only Using IN Data



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ETR_00000785

Figure 7-3. Operating Cost Sensitivity to Reagent Stoichiometry – LSD/FF Using IN Data

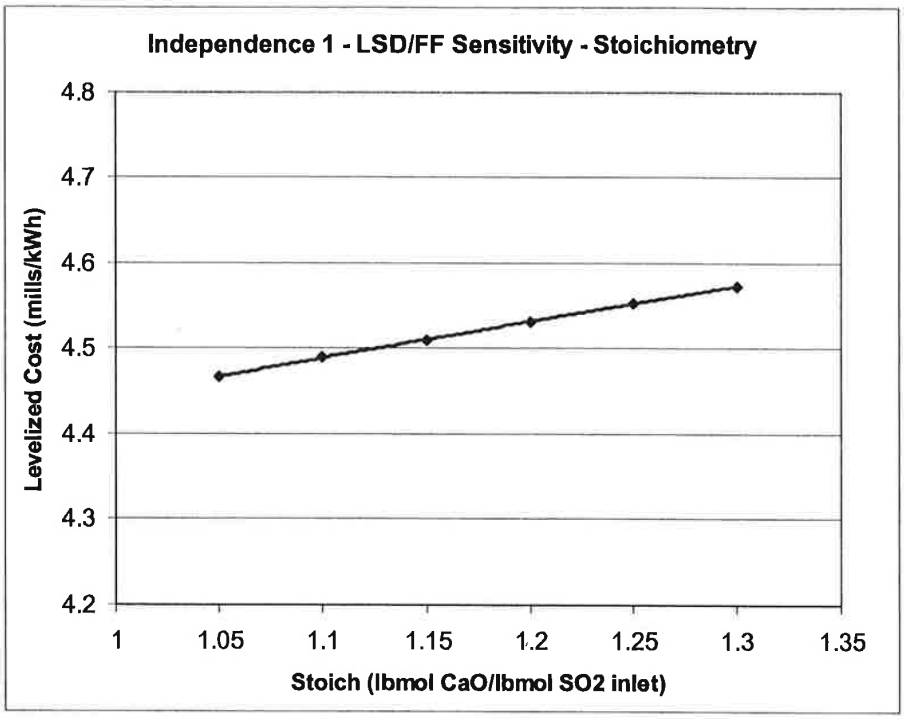

Figure 7-4. Operating Cost Sensitivity to Coal Sulfur Content – LSFO Using IN Data

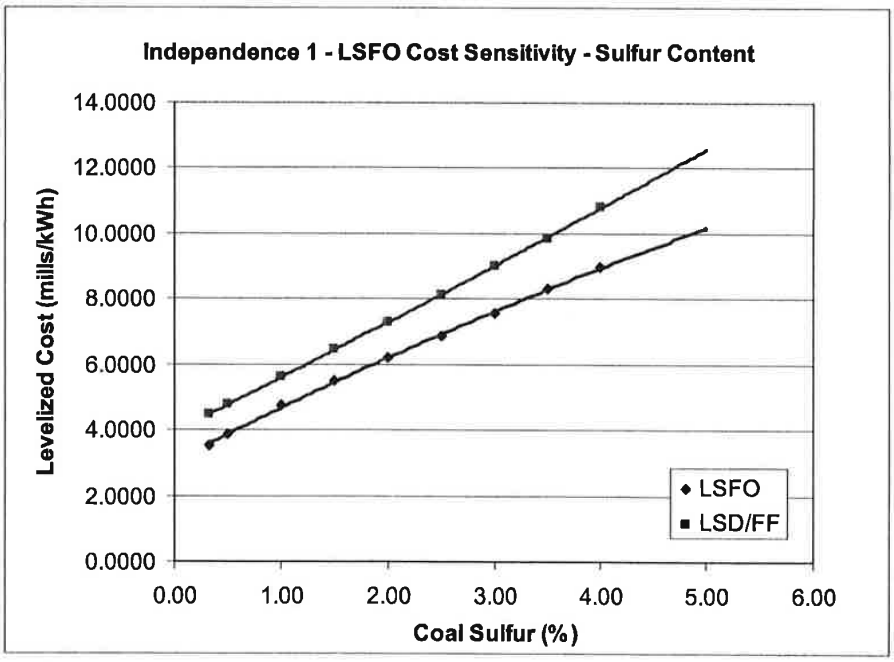

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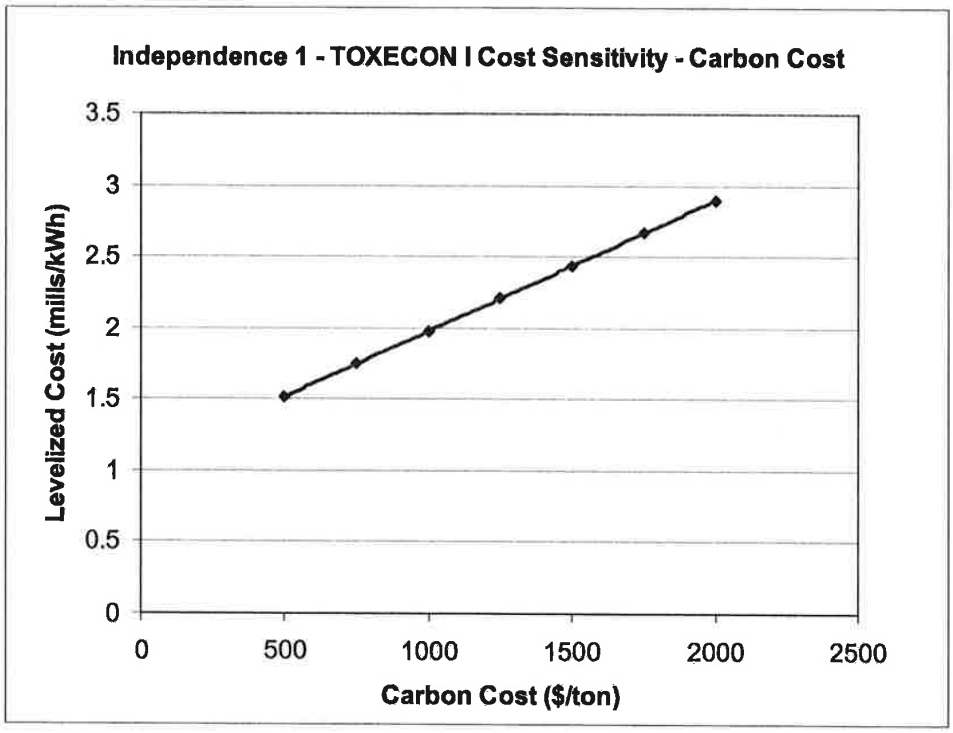
Figure 7-5. Cost Sensitivity to Activated Carbon Price



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ETR_00000787

Appendices

A Listing of FGD, NOx and Mercury Control Technologies

B Estimate Basis

C Site Datasheets

D Cost Estimate Summary Sheets from IECCOST

E Levelized and Operating Cost Breakdowns for Each Unit

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ETR_00000788

Appendix A – Technology Listings for FGD, NOx Control, and Hg Control

SO_2 CONTROL PROCESSES

FGD Process Name	Description	By-Products / Waste	Other Removal	Pass/Fail Based on Mandatory Criteria♦
WET FGD PROCESSES				
ASFO	Ammonium sulfite is formed in the absorber by the reaction of SO2 with ammonia and then is completely oxidized to an ammonium sulfate product	Ammonium sulfate byproduct	None	Fail-4
Wet Limestone Forced Oxidation	A wet slurry, throwaway system, where limestone slurry is contacted with flue gas	Gypsum byproduct	None	Pass
Wet Limestone Inhibited Oxidation	Emulsified sulfur or sodium thiosulfate added to slurry feed	Calcium sulfite waste	None	Fail- - 4
Wet Lime	Hydrated lime slurry in a countercurrent spray tower	Calcium sulfite and wet sludge waste	None	Fail – 4
Wet Sodium Carbonate	SO2 contacted with a spray of sodium carbonate solution	Sodium sulfite and Sodium sulfate waste	None	Fail – 4
Seawater	Natural alkalinity of seawater utilizes SO_2	None	None	Fail – 5
Sodium Sulfite Process (Wellman-Lord)	Sodium sulfite solution into pretreated flue gas	Sodium sulfite/bisulfite liquor	None	Fail – 4
Magnesium Oxide	Magnesium oxide slurry is used to absorb SO_2	Magnesium sulfite/sulfate by-product	None	Fail – 4
Combined SO2 and NOx high velocity scrubber	Uses dolomitic lime scrubbing and corona reactor	Mixed calcium sulfite, sulfate, nitrate solids	NOx	Fail – 4
Combined SO2NOx	Utilizes low temperature oxidation of NO by ozone injection, followed by a wet scrubber	Mixed calcium sulfite, sulfate, nitrate solids	NOx	Fail – 1
ThioClear®	Forced oxidation magnesium-enhanced lime process	Gypsum and magnesium hydroxide byproducts	None	Pass – similar to wet limestone
Mitsubishi Liquid Column Type Absorber (DCFS)	Gas/liquid contact achieves high desulfurization and dedusting efficiency	Wastewater	Particulates	Fail – 1
Forced Oxidation Gypsum (FOG)	Wet-lime based forced oxidation to gypsum	Gypsum byproduct	Fly Ash	Pass – similar to wet limestone
Benetech "Pircon Peck Process"	Wet phosphate-rock/ammonia process	Ammonium phosphate byproduct	None	Fail – 2
Benetech "Clean and Green"	Wet ammonia process with regenerating diammonium phosphate	Ammonium sulfate byproduct	None	Fail - 1

♦Mandatory Criteria that the Process fails to meet:
1 – Commercially proven and/or currently available
2 – Compatible with projected fuel
3 – Does not cause increase in current emission limits
4 – Produces an acceptable waste product (large fraction of soluble salts unsuited to landfill)
5 – Reagent available at the plant

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ETR_00000789

FGD Process Name	Description	By-Products / Waste	Other Removal	Pass/Fail Based on Mandatory Criteria♦
Bischoff Wet Ammonia FGD	Combines multi-step, open packed-tower, single-scrubber design with a wet ESP mist eliminator	Ammonium sulfate solids byproducts	None	Fail – 4
LBL and Bechtel Scrubber (PhoSNOX)	Yellow phosphorous into the scrubber along with calcium-based slurry	Phosphoric acid and gypsum byproduct	NOx	Fail – 1
Packaged Wet Scrubbing	Sodium carbonate or sodium hydroxide used as a neutralizing agent for SO_2	Waste Sodium salt Solution	None	Fail – 4
Fluidized-Bed Copper Oxide	Regenerative with copper oxide into SO2 and O2 and ammonia into flue gas	Elemental Sulfur Or Sulfuric Acid	NOx	Fail – 1
Dual Alkali (Limestone Regeneration)	Limestone used to regenerate sodium sulfite	Slurry waste	None	Fail – 4
Sulf-X	Regenerating iron sulfide waste material used as an absorbent	Elemental-sulfur byproduct	NOx	Fail – 1
Citrate Scrubbing	SOx is absorbed in a buffered solution of sodium citrate and is contacted with H_2S to form sulfur	Dry solids, sulfur product, and slurry waste	None	Fail – 1
Kruger System	Ammonia and seawater into flue gas	Liquid or crystallized fertilizer byproduct	None	Fail – 5
SOXAL	Utilizes Aquatech bipolar membrane electrodialysis system and conventional wet scrubbing technology to provide regenerable FGD	Sulfur byproduct	NOx, HCl	Fail – 1
Chiyoda Thoroughbred 121	Jet bubbling reactor (containing some limestone) scrubs the flue gas	Dry gypsum byproduct	None	Evaluated as LSFO
Hoogovens' 'Bio-FGD'	Absorber and two biological reactors remove SO2 from flue gas	Elemental sulfur byproduct	Heavy metals	Fail – 1
Union Carbide's 'CanSolv'	Regenerable organic amine salts into gas stream in scrubber reacts with SO_2	Sulfuric acid or sulfur	None	Fail – 1
ISCA Flue Gas Treatment	Chlorine Oxidation of SO_2 and NOx	Mixed salts waste	NOx, Heavy metals	Fail – 1
DOW Chemical FGD Process	Amine based	Liquid SO2 byproduct	None	Fail – 1
Georgia Tech Research Corp.'s 'Regenerative Method for Removal of SO2 from Stack Gases'	SO_2 is absorbed into an acidic scrubbing solution containing regenerable barium dioxide	Fly ash waste	None	Fail – 1
TurboTak Waterloo Wet Scrubber	Introduces basic oxygen furnace fumes in slurry form into the SO2 gas phase	Sludge waste	Particulates, NOx, H_2S, Organics	Fail – 1
Airborne Wet Scrubbing	Introduces wet sodium carbonate into flue gas stream	Fertilizer byproduct	None	Fail – 1

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ETR_00000790

FGD Process Name	Description	By-Products / Waste	Other Removal	Pass/Fail Based on Mandatory Criteria♦
DynaMotive Tech. 'BioLime'	BioLime (mixture of lime and oil derived from organic wastes) injected into coal combustors	Char and gypsum byproduct	NOx	Fail – 1
RTI-Waterloo Process	Low-temperature process employing activated carbon-based catalysts and operates down-stream of the ESP	Sulfuric acid	NOx	Fail – 1
Sly Impinjet→ Gas Scrubber	Turbulent conditions insure intimate contact between the gas contaminants and the scrubbing solution	Slurry waste	Particulates	Fail – 1
ThioSorbic	Scrubbing of flue gas, regeneration of scrubbing liquor, and dewatering	Calcium Sulfite, Magnesium Sulfite	None	Fail – 4
LS-2 Wet FGD	Limestone into flue gas	Gypsum byproduct	None	Evaluated as LSFO
Abdelmalek Assoc. FGD Cleaning by Condensing and Liquefaction	Process based on thermodynamic equilibrium of gases contrast to chemical reaction with variety of re-agents to extract pollutant gases	Solid wastes	NOx	Fail –1
Elsorb FGD	Regenerable phosphate system	Phosphate fertilizer	None	Fail – 1
Electrolytic Regeneration	Based on the absorption of SO_2 in an aqueous solution of NaOH to form sodium sulfite and bisulfite that then react with H_2SO_4 to release SO_2 which is evolved as a pure gas and form Na_2SO_4 solution	Na_2SO_4	None	Fail – 1
Norwegian Institute of Tech. Adipate Process	Use of aqueous sodium adipates in absorption-stream stripping	SO2, H2SO4, Elemental Sulfur	None	Fail – 1
CIBA-GEIGY SO2 Sorption	Steam Stripping with aluminum sulfite solution process liquor	Solid waste	None	Fail – 1
Erga-Peterse-Process	SO_2 absorption from buffered, aqueous caustic soda and strips it via H_2 stream	Elemental sulfur, liquid SO2, concentrated sulfuric acid, ammonium sulfate	None	Fail – 1
Moser & Owens Clear-Liquor Scrubbing Process	Sludge bed reactor and organic acid additives in a clear liquor to reduce sulfur emissions	Calcium sulfite/sulfate solids	None	Fail – 1
Stauffer Technology Sulfuric Acid Process	Utilizes a scrubber with an electrically conductive packing material	Sulfuric acid	None	Fail – 1
Caldyn GmbH's Scrubber	Two-stage removal system with lime and water injection	Calcium sulfate	None	Fail – 1
Condensing Heat Exchangers (CHE)	Two-stage flue-gas treatment including a down flow heat exchanger and an up flow heat exchanger	Wastewater	SO_3, HCl, fly ash, metals, VOC's	Fail – 1
B&W's Magnesium-Enhanced Lime (MEL) Process	Wet limestone scrubber design with magnesium hydroxide representing 5 or less percent of the lime slurry	Sludge waste	None	Fail – 4

Confidential Business Information
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ETR_00000791

FGD Process Name	Description	By-Products / Waste	Other Removal	Pass/Fail Based on Mandatory Criteria♦
Kawasaki Heavy Industries (KHI) Process	Wet limestone scrubber design where magnesium hydroxide represents 0.4-0.5% of the lime slurry	Sludge waste	None	Evaluated as LSFO
Chemico and Mitsui Wet Limestone Scrubber System	Integrated single wet limestone scrubber	Gypsum byproduct	None	Evaluated as LSFO
SHU's Formic-Acid, Enhanced, Wet Limestone System	Wet limestone scrubber	Gypsum byproduct, solid waste	None	Evaluated as LSFO
Dravo's Wet Thiosorbic Magnesium-Enhanced Lime System	Magnesium-enhanced lime wet scrubber	Gypsum byproduct, solid waste	None	Pass – similar to wet limestone
Bleed Stream Oxidation (BSO)	Wet scrubbing process that combines features of the Thiosorbic Lime FGD with ThioClear	Gypsum byproduct	None	Pass – similar to wet limestone
Cat-Ra Technology	Wet process where a potassium sulfite solution is fed into the scrubber where it reacts with SO_2	Potassium sulfate fertilizer, magnesium chloride	NOx	Fail – 1
AMASOX (previously the Walther Process) – Wet Ammonia Scrubber	Spray injection of aqueous ammonia produces ammonium sulfate which is subsequently oxidized to sulfate	Ammonium salt fertilizer	None	Fail –4
Seawater Scrubbing by Lentjes/Bischoff Co.	Seawater in the scrubber comes in contact with cooled flue gas	None	None	Fail – 5
ThioClear/TecoLytic	Combines the removal of SO_2 and NOx in a horizontal wet scrubber. TecoLytic technology employs low energy plasma to generate large numbers of radical species that promote chemical decomposition.	Calcium nitrate byproduct	NOx	Fail – 1
Water Treatment Sludge Reagent in FGD System	Use of calcium carbonate waste sludge from a municipal water treatment plant as a reagent substitute for limestone	Gypsum byproduct	None	Fail – 5
Dibasic Acid Enhanced Limestone (DBA/LSFO)	DBA acts as a buffer/catalyst in the spray tower recirculation tank. Limestone slurry sprayed into an open spray tower absorbs the SO_2 present in the flue gas.	Calcium sulfite/sulfate sludge, gypsum byproduct	None	Evaluated as LSFO
Pure Air Advanced FGD	Wet system that uses a co-current, down flow absorber with a single level of grid packing. Limestone slurry is sprayed into the absorber tower above the grid and is contacted by the flue gas.	Gypsum byproduct	None	Evaluated as LSFO
NSP Bubbler Scrubber Process	Flue gas passes through the ID/Booster fans before entering the bubbler scrubber. The gas is bubbled through a limestone/gypsum slurry, that absorbs the SO_2	Fly ash waste, gypsum byproduct	None	Evaluated as LSFO

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ETR_00000792

FGD Process Name	Description	By-Products / Waste	Other Removal	Pass/Fail Based on Mandatory Criteria♦
Passamaquoddy Recovery Scrubber Process	Wet FGD system where cooled flue gas enters a bubbling reactor where it contacts dilute potassium oxide and calcium hydroxide slurry	Calcium carbonate, potassium sulfate	None	Fail – 4
Saarberg-Holter (S-H) Process	Wet scrubbing that uses formic acid to buffer and control pH drop of the absorbing slurry to enhance SO_2 absorption	Gypsum byproduct	None	Evaluated as LSFO
Organic Acid Enhanced Limestone	A wet, throwaway system where limestone slurry solution, buffered with either adipic or dibasic acid, is used in a spray tower to absorb SO_2	Calcium sulfite/sulfate sludge	None	Evaluated as LSFO
Pfizer Sultrol Process	Regenerable, wet system where potassium citrate solution is sprayed into a packed tower to remove SO_2	Elemental sulfur	None	Fail – 1
Flakt-Boliden Process	Regenerable, wet system where sodium citrate solution is used in a packed tower to remove SO_2	Elemental sulfur	None	Fail – 1
CONOSOX	Regenerable, wet process where a solution of potassium carbonate and other potassium salts are used to remove SO_2 in a packed tower	Elemental sulfur	None	Fail – 1
Dowa Process	A wet, regenerable scrubbing process where an aluminum sulfate/aluminum hydroxide solution is used to remove SO_2	Gypsum byproduct, fly ash waste	None	Fail - 1
DRY FGD PROCESSES				
PowerSpan's ECO	Dry ESP removed fly ash in flue gas stream, stream then passes through a barrier discharge reactor where gaseous pollutants are oxidized and nitric and sulfuric acids are produced. These acids form aerosol mists that are collected on the wet ESP.	Nitric and sulfuric acid byproducts, fly ash waste, heavy metal waste	NOx, Hg, HCl, Arsenic, SO_2, HF, Particulate	Fail - 1
ABB's SNOX	SO_2 is catalytically oxidized to SO_3 and NOx is converted to N through selective catalytic reduction	Sulfuric Acid byproduct	NOx	Fail – 1
Lime Spray Drying	Contact of a finely atomized slurry of hydrated lime with flue gas.	Calcium sulfite/sulfate, unused hydrated lime, fly ash	None	Pass
Dry Sorbent Injection	Flue gas contacts a finely dispersed sorbent	Fly ash, reaction products, and any unreacted sorbent	None	Fail - 2
Duct Spray Drying	Flue gas contacts atomized lime slurry	Calcium sulfite/sulfate, unused hydrated lime, fly ash	None	Fail – 1
Circulating Fluidized Bed	Dry sorbent (most often calcitic) into humidified flue gas	Particulate matter	None	Pass
Dry Sodium Injection	Sodium Bicarbonate into Duct	Dry sodium salt waste	NOx	Fail - 4

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ETR_00000793

FGD Process Name	Description	By-Products / Waste	Other Removal	Pass/Fail Based on Mandatory Criteria♦
Membrane Contactor ElectroDialysis (MCED)	SO_2 absorption in membrane contactor (MC) and regeneration of the spent absorbent by electrodialysis (ED) w/bipolar membranes.	Byproduct of SO_2 or SO_2 derivatives as sulfur product	None	Fail – 1
Electron Beam with Ammonia (EBA)	Dry mode consisting of gas cooling of dedusted flue gas, followed by ammonia injection and electron beam irradiation, followed by byproduct collection and reprocessing	Ammonium solid byproducts	SO_3 and NOx (and all other acid gases)	Fail – 1
Electron Beam Irradiation	SO_2 and NOx are converted to aerosols formed by ammonia salts particles	Ammonium sulfate and ammonium nitrate mixture byproduct	NOx	Fail – 1
SOx/NOx Adsorption Process (SNAP)	Fluid bed with sodium carbonate on alumina substrate	Sulfur byproduct	NOx and HCl	Fail – 1
Enelco Synthetic Nahcolite (SNP)	Nahcolite (as-is or calcined) injection into flue gas	Solid waste	NOx	Fail – 1
E-Sox	Combines advanced ESP technology with spray-dryer desulfurization in an existing ESP box	Liquid effluent	None	Fail – 1
Aqueous Carbonate (Atomics Int.)	SOx is removed in a spray dryer wherein aqueous sodium carbonate is evaporated to dryness	Sulfur product, chloride containing waste stream	HCl	Fail – 1
Cha Corp. SOx/NOx Destruction	SO_2 is absorbed on coal char, is heated by microwaves, where SO_2 is catalyzed to sulfur and oxygen. O_2 reacts with char, producing CO_2 and activated charcoal. NOx is decomposed via microwaves to Nitrogen and Oxygen.	Charcoal byproduct	NOx	Fail – 1
Bicar Process (by Solvay Brussels)	Dry bicarbonate particles into flue gas as it enters baghouse	Sodium carbonate, sodium sulfate, and sodium chloride waste	HCl, NOx	Fail – 1
LIFAC	Limestone injected into upper boiler region calcines to lime and absorbs some SO_2. Gases then move through the air preheater and enter the activation chamber where they are humidified and SO_2 capture is completed.	Fly ash waste	None	Fail – 1
MaC-100 System	Tail gas stream passes through a fixed bed of special Centaur granular activated carbon, wish absorbs the gas into it's pores and catalytically converts it into sulfuric acid	Dilute sulfuric acid for make-up use	None	Fail – 4

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ETR_00000794

FGD Process Name	Description	By-Products / Waste	Other Removal	Pass/Fail Based on Mandatory Criteria♦
NIRO SOx/NOx	Recirculated dry waste product and slaked lime are mixed into a slurry and is then atomized in the spray dryer absorber module where it is mixed with the flue gas, creating a recycle product	Sodium sulfite???	NOx	Fail – 4
Strathmore Dry FGD System	Lime alkali into flue gas	Calcium sulfite/sulfate, fly ash, unreacted lime	Particulates	Fail - 1
Sorbent Tech. Dry Injection System	Mixture of vermiculite and perlite injected with lime	Fertilizer byproduct	Particulates	Fail - 1
Airborne Dry Sorbent Injection	Introduces dry sodium bicarbonate into flue gas stream	Fertilizer byproduct	NOx	Fail - 1
SCONOx/SCOSOx by Goal Line Environmental Technologies	Catalysts favor the absorption of either sulfur compounds or NOx	Mixed acid neutralized to form calcium sulfate/nitrate	NOx, CO, VOC's	Fail – 1
Copper Oxide Bed Regenerable Application (COBRA)	Stream of copper oxide beads convert SO2 and NOx to elemental sulfur and pure nitrogen gas	Sulfuric acid and fertilizer byproduct	NOx	Fail – 1
WULFF Dry FGD	Dry-type scrubbing using a reflux circulating fluid bed	Solid waste	HCl, HF, SO_3, NOx, Dust	Similar to CFB
Copper Oxide	Uses dry acceptor, CuO, on alumina, in a fixed bed reactor, to extract sulfur oxides from flue gas containing oxygen and particulate matter. Acceptor is regenerated on-site to release the sulfur as SO_2 in the regeneration off-gas.	Liquid SO2 or elemental sulfur	NOx	Fail – 1
Uhde's 'Bergbau-Forschung-Uhde' system	Flue gas treated by adsorption and catalytic reduction with activated coke, derived from hard coal	Fly ash	None	Fail – 1
RCM's Electro-Chemical Sulfur Oxide Concentrator	Electro-chemical reactions transform SO_2 into a heavily concentrated gaseous form of sulfur trioxide	Sulfur trioxide and liquid NOx byproducts	NOx	Fail – 1
Bechtel's Confined Zone Dispersion (CZD) Process	Sprays a finely atomized slurry of pressure hydrated dolomitic lime into ductwork downstream of air heater	Mixed ash and sulfite/sulfate waste solids	Fly Ash	Fail - 1
Flakt Dry Scrubber	Ljungstrom type regenerative heat exchanger	Mixed waste solids	Particulate	Evaluated as LSD
GEESI's 'In-Duct Scrubbing (IDS)'	Lime slurry injection with a rotary atomizer directly into existing ductwork without utilizing a reaction vessel	Ash waste	Fly Ash, reaction products	Fail - 1
Dravo Corps 'Hydrate Addition at Low Temperature (HALT)'	Injection of a prepared calcium hydroxide (hydrate) into a duct with humidification and/or temperature control of the flue gas	Mixed ash and sulfite/sulfate solids	None	Fail - 1

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ETR_00000795

FGD Process Name	Description	By-Products / Waste	Other Removal	Pass/Fail Based on Mandatory Criteria♦
Mark 13A Process	Bromine injection into flue gas to form sulfuric acid, concentrating acid while evaporating water and hydrobromic acid, electrolyzing hydrobromic acid to bromine and hydrogen	Sulfuric acid byproduct	None	Fail – 1
SIU and ICCI's Plasma Chemistry Process	Plasma chemistry to convert SO_2 to H_2SO_4, the plasma being produced by a dielectric-barrier discharge	Dilute sulfuric acid	None	Fail – 1
Schott Eng. GmbH's Absorption Process	Packed absorber column containing peroxide reacts with SO_2	Mixed dilute acid	HCl	Fail – 1
Trident Industries' 'Fluegas Control'	Packed limestone column	Calcium salts	Dust, chlorine, fluorine, NOx	Fail – 1
Flue Gas Purification System (FGPS)	Dry process that converts SO_2, NOx, and SO_3 to acidic aerosols for easier neutralization and removal in a bag-house	Mixed waste solids	NOx, SO3	Fail – 1
SOx-NOx-Rox-Box (SNRB)	High-temperature catalytic fabric filter	Waste	NOx, particulates	Fail – 1
DESONOX	Flue gas mixes with NH3, enters the reactor where NOx is reduced catalytically, followed by oxidation of SO_2 to SO_3	Sulfuric acid	NOx	Fail – 1
Parsons Flue Gas Cleanup	Steam-methane reformer gas and tail gas recycled from the sulfur plant into flue gas to form the feed to the catalytic hydrogenation reaction module where SOx and NOx are reduced	Elemental Sulfur	NOx	Fail – 4
Lurgi CFB	Hydrated lime used as sorbent for SO_2 removal, deNOx reduction is a SCR using ammonia as the reducing agent.	Dry products	NOx	Pass - CFB
NOXSO	Sorbent consisting of spherical beads of high surface area alumina (impregnated with sodium carbonate) simultaneously removes SOx and NOx in two parallel fluidized bed adsorbers.	Elemental sulfur	NOx	Fail – 1
Activated Carbon	SO_2 is oxidized and adsorbed on the activated carbon surface in the form of sulfuric acid and NOx removal reaction includes the same catalytic reaction as in SCR	Sulfuric acid	NOx	Fail – 1
Furnace Sorbent Injection	Direct injection of the dry sorbent (typically $CaCO_3$, $Ca(OH)_2$, and dolomite) into the furnace	Calcium sulfite and sulfate	None	Fail - 1

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ETR_00000796

FGD Process Name	Description	By-Products / Waste	Other Removal	Pass/Fail Based on Mandatory Criteria♦
ADVACATE	Injection of prepared calcium silicate into the ductwork	Calcium silicate & sulfite	None	Fail - 1
In-Duct Scrubbing (IDS) – Duct Sorbent Injection	Injecting a slaked lime slurry with a rotary atomizer directly into existing ductwork	Calcium sulfite	None	Fail – 1
Coolside – Duct Sorbent Inject.	Sodium additive dissolved in the humidification water	Calcium sulfite	None	Fail - 1
Hybrid Pollution Abatement System (HYPAS)	Initial removal of fly ash by an existing ESP. Humid. and hydrated lime injection in the ash-free environment between the ESP and pulse-jet fabric filter retrofitted	Calcium sulfite	None	Fail - 1
Dry Sodium Injection – Duct Sorbent Injection	Injection of sodium compound into the ductwork, followed by a fabric filter	Sodium sulfate	None	Fail - 1
Duct Slurry Injection – Duct Sorbent Injection	Slurry sorbent injection into the ductwork. Dry sorbent reactivation process.	Calcium sulfite	None	Fail - 1
ABB's New Integrated dry flue gas Desulfurization (NID)	Based on absorption of SO_2 by a dry absorbent containing quicklime (CaO) or dry hydrated lime ($Ca(OH)_2$)	Waste product	None	Fail - 1
B&W's Enhanced Limestone Injection Dry Scrubbing (E-LIDS)	Limestone-based furnace injection/dry scrubbing SO_2 removal process	Solid waste	Particulates	Fail - 1
Gas Suspension Absorption (GSA)	CFB reactor where suspended solids (reaction products, residual lime, fly ash contact the flue gas.	Solid byproduct material	Particulates	Evaluated as CFB
Moving Bed Dry Scrubber	Dry absorbent from coal ash/lime – moving bed scrubber	Mixed waste solids – ash, sulfite/sulfate	None	Fail – 1
Economizer Sorbent Injection (EI)	Hydrated lime is injected into the flue gas stream near the economizer zone	Calcium Sulfite	None	Fail - 1
TNO Membrane Gas Absorption	SO_2 in flue gas diffuses through gas-filled pores of a micro-porous, hydrophobic, hollow fiber membrane module. The SO_2 is absorbed in the absorption liquid on other side.	Absorption liquids	CO2, H2S, NH3, HCl	Fail - 1
Mitsui-DESOX Process	Dry regenerable process involving the adsorption of flue gas SO_2 in a bed of activated coke	Elemental sulfur, sulfuric acid	None	Fail - 4
Froth Flotation Coal Cleaning	Regenerable dry process	Iron Sulfides, Ash	None	Fail - 2

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ETR_00000797

NO_x CONTROL TECHNOLOGY OPTIONS

Process Name	Description	By-Products / Waste	Other Removal	Pass/Fail Based on Mandatory Criteria♦
Selective Catalytic Reduction	Reducing catalyst placed in the flue gas path and ammonia injected to convert NOx to N_2 and O_2	Depleted catalyst and SO_3 in exit gas	None	Pass
Low NOx Burners (LNB)	New burners installed to replace existing units in the boiler – produces reducing conditions and lower flame temperatures to reduce thermal NOx production	LOI can increase in fly ash, potentially making the ash unmarketable	None	Pass
Mobotec Rotating Over-fire Air (ROFA)	ROFA system uses fans to inject combustion air into the furnace producing a rotation of combustion gas and better mixing. The Rotamix variation is not considered here, which requires the injection of urea or ammonia into the back pass of the boiler	With Rotamix, ammonia slip is typically much higher than SCR – With ROFA, no wastes created	None	Pass
Excess Air Control	Control air feed rate to the burners	Can increase CO emissions & carbon in fly ash	None	Fail – 1
Boiler Fine Tuning	Evaluate all aspects of boiler combustion settings – mill fineness, air and coal flow balancing, air registers, burner controls, etc.	Potential decrease in plant heat rate	None	Fail – 1
Over Fire Air/Air Staging	Divides the combustion zone into two separate areas – primary air is divided, with 70-90% mixed with the fuel in the burners, and the rest injected above the primary combustion zone. Helps to reduce the flame temperatures and thermal NOx production rates. Sometimes combined with LNBs to achieve higher NOx removal.	Can increase CO emissions & carbon in fly ash. Typically adjust the system to keep CO below 50 ppm and unburned carbon to 5%	None	Pass
Induced Flue Gas Recirculation on Coal Units	Using the existing fans to bring flue gas back into the air feed to the boiler to reduce the peak flame temperature. Coal boiler installations have not been successful due to flame stability problems and reduced combustion efficiency.	Increase in carbon content of the fly ash can be significant	None	Fail - 1
Reburning/Fuel Staging	Can be implemented by taking burners out of service (BOOS) or other fuel biasing methods to produce fuel-rich zones in the furnace. Divides combustion zone into three stages – primary combustion, reburn, and burnout. A fraction of the boiler fuel (10-30%) is injected into the upper furnace. Reburn fuels = gas, oil or coal.	Changes the boiler heat distribution and potential reductions in combustion efficiency.	None	Fail – 6
Neural Network for Boiler Combustion Control	High-speed computer software used to continuously evaluate boiler operating parameters. Emission reduction results have varied.	Performance is specific to each site.	None	Fail – 1
Other Developing Technologies	Many processes have been developed over the last two decades. Few are commercial at this time.	Varies with process		Fail – 2

♦Mandatory Criteria that the Process fails to meet:
1 – Capable of 20-90% NOx Removal
2 – Commercially proven and/or currently available
3 – Compatible with projected fuel
4 – Does not cause increase in current emission limits
5 – Produces an acceptable waste product
6 – Reagent available

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ETR_00000798

Other NOx Control Options (Note: All of these processes were rejected because they do not have any commercial operating experience on large coal-fired boilers)

SCONOx Catalytic System
Todd Rapid Mix Burner
Ashworth Combustor
NOxTECH System
Advanced Energy Research Catalytic Reburning
Lockwood Greene Low Temperature SCR
SCR with Ozone Reagent
Georgia Tech Ceramic Membrane
Lehigh Low Temperature SCR
Taylium Metal Grid
IGR Solid State Electrolytic Cell
Argonne Mixed Alkali Spray Dryer
ThioClear/Tecolytic Corona Reactor
ISCA Chlorine Oxide Process
Battelle Regenerative Zinc Oxide
Procedair Liquid Phase NOx Catalyst
Abdelmalek Condensing/Liquefaction System
Krestew Process
Pulsatron Technology
Nahcolite Injection

DynaMotive BioLime Process
dK-Teknik Farm Slurry Process
Trident Industries Limestone Rock
Flue Gas Purification Process
Steag/ISGS Carbon Adsorbent
Lawrence Berkley Labs PHOSNOX
Concord Scientific Ultraviolet System
NOXSO/SNAP Adsorbent
SOx/NOx/ROx/Box (SNRB)
EBARA/E-Beam
Mitsui Activated Carbon Process
Shell/UOP/Copper Oxide
ENEL Pulsed Energization
Iron Chelate/Mag Lime Process - Dravo
WSA/SNOX - Alstom
SOXAL Membrane Process
Cha Electromagnetic Process
Lawrence Livermore Iron Thiochelate

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ETR_00000799

MERCURY CONTROL TECHNOLOGY LISTING

Process	Description	By-Products / Waste	Other Removal	Pass/Fail Based on Mandatory Criteria♦
Activated Carbon Injection TOXECON I TOXECON1.5 TOXECON II	TOXECON I = Inject activated carbon into duct work upstream of a COHPAC pulse-jet baghouse TOXECON 1.5 = Convert last field of existing ESP to baghouse and inject ACI upstream of FF portion TOXECON II = Inject ACI upstream of last field of existing ESP	Ash contaminated with carbon unless install a new particulate collector in TOXECON I case. Other two options separate carbon by physically collection the AC downstream of primary particulate removal	None	Pass – Note that none of the ACI system options have been operated for long periods of time on utility boilers
Amended Silicate Injection	Sorbent produced from fly ash and additives	No carbon added to ash, so less impact on sale	None	Fail – 1
Co-benefits from FGD & SCR	The oxidation of elemental mercury, and subsequent collection of the oxidized Hg can provide significant reductions in total Hg emissions	Mercury ends up in FGD waste or byproduct. Concentration is low.	NOx and SO_2	Fail – 1
Powerspan	Electro-Catalytic Oxidation followed by wet scrubbing	Oxidized Hg is collected in a downstream wet scrubber	Hg in byproduct, or extracted into C bed	Fail – 1
MerCAP	Gold coated plates forming AU-Hg amalgam	Regeneration products	None	Fail – 1
ISCA	Chloric Acid or Chlorine injection to oxidize elemental Hg	Hg in product	NOx and SO_2	Fail – 1
Corona Discharge Reactor	Electrical oxidation of elemental Hg and subsequent collection in a wet scrubber downstream	Hg will end up in byproducts unless removed	NOx	Fail – 1
Fluid and Fixed Bed	Activated carbon in fluid bed or fixed bed applications	Hg regeneration or contamination of carbon	None	Fail –1
Wet FGD Additives	Additives to enhance collection efficiency of wet scrubber by reducing the Hg vapor pressure over the scrubbing slurry	Hg concentration in FGD waste or byproduct will increase, along with adding additive to products	None	Fail – 1
Hg Oxidation with Catalyst	Oxidation catalyst installed in flue gas upstream of an FGD system, oxidizing Hg to allow absorption	Hg ends up in FGD solids	None	Fail – 1
Thermal Treatment of Coal	Western Research investigating treatment of PRB and other fuels to drive off Hg prior to combustion. Operates below 570°F.	Alternate Hg emission source	None	Fail – 1
Carbon Inserts into Baghouse	Gore testing inserts for pulse-jet fabric filters	Hg impregnated inserts	None	Fail – 1
Pahlman/EnviroScrub	Manganese Oxide injection into flue gas removes SO_2, NOx and Hg	Pahlmanite waste solid fines after regeneration	NOx & SO_2	Fail – 1
Lextran	Ozone injection		NOx & SO_2	Fail – 1

♦Mandatory Criteria that the Process fails to meet: 1 – Commercially proven and/or currently available

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ETR_00000800

Appendix B - **Estimate Basis**

Attached is a summary of the primary assumptions that will be used during the cost estimating process:

WASHINGTON GROUP INTERNATIONAL

ESTIMATE BASIS

CLIENT:	**Entergy**	**PROJ MANAGER:**	**R. Keeth**
PROJECT:	**Emissions Control Project**	**ESTIMATOR:**	TBD
LOCATION:	**AR and LA**	**DATE:**	**Sept. 2004**
JOB NO:	**27447-012**	**REVISION NO:**	**0**

1.0 ESTIMATE REQUIREMENTS

A. Emissions control systems to reduce the SO_2, NOx, and mercury emissions from all coal-fired units operating in the Entergy system. Emission rate limits and inlet concentrations for various operating loads and fuels provided by Entergy.

2.0 SCOPE OF WORK:

A. Definition From:
Washington Group International Proposal

B. Scope of Work:
Assessment of economic viability of the retrofit of emissions control systems for five units in the Entergy system to meet future emissions limits established by the EPA. Scope of work for the retrofit installations will include the following:

- Common chemical storage and supply systems for each plant, when required.
- Piping of this solution to the vaporizer skids dedicated to each individual unit
- FGD and SCR reactors, where required
- Injection grids, where required
- Caissons, foundations and structural steel
- Insulated ductwork tie-ins to existing flue gas system
- Dampers and expansion joints
- Local PLC control systems and signal to existing control room
- Instrumentation for control signals
- Construction management and indirect costs associated with installation of all components
- Construction labor
- Construction equipment and temporary construction support systems
- Electrical system upgrades, cable, and tie-ins, including use new MCC's and switchgear to supply power to the new equipment

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3.0 ENGINEERING PRICING BASIS

__10__% of Total Project Cost
__20__% Contingency

4.0 ASSUMPTIONS AND QUALIFICATIONS

Cost estimates are based on the following:

- Budgetary estimates generated using in-house economic models, historical information for major components, cost data from Entergy, or published data.
- Engineering estimated at 10% of the installed capital cost for each system.

It should be noted that the cost estimates provided herein are dependent upon the various underlying assumptions, inclusions and exclusions utilized in developing them. Actual project costs will differ, and can be significantly affected by factors such as changes in the external environment, the manner in which the project is implemented, and other factors which impact the estimate basis or otherwise affect the project. Estimate accuracy ranges are only projections based upon cost estimating methods and are not a guarantee of actual project costs.

5.0 CONSTRUCTION PACKAGES

One EPC contract assumed for each retrofit.

6.0 SCOPE CLARIFICATIONS

1. The Plant Estimate is based on an EPC/Turnkey Mechanical package.
2. Labor costs are based on utilizing union labor on a 40-hour workweek
3. The following Owner/Development costs are excluded from this estimate:
    - Permitting
    - Insurance, Bonds, Taxes. etc.
    - Plant Staffing and Training
    - Utilities During Construction
    - Owner Temporary Facilities
    - Fuel and Chemicals
    - Spare Parts
4. An allowance for additional buildings or facilities is included in the capital cost estimate at 10% of the installed equipment cost.
5. Landscaping and seeding/planting is not included.
6. Reagent storage is based on 30 days at full load for each retrofit.
7. The Emissions Control system additions have been assumed to have no impact to the boiler heating surfaces, pressure parts or gas paths (through each unit's economizer outlet).
8. Pollution Control Equipment Installations are exempt from State taxes in LA and AR.

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ETR_00000802

APPENDIX C – Site Datasheets Supplied by Entergy

Entergy Emissions Control Project

Plant Data

Entergy completed the following plant data and returned this information to Washington Group International in August 2004. Remaining data was gathered during site visits and discussions with Entergy personnel held the week of 8/23/04. This information served as the basis for the analyses performed for the Emissions Control Study.

Independence Plant
Newark, AR

	Plant / Unit	*Independence 1*	*Independence 2*
A.	***Unit Information:***		
	Commercial Operation	*January 18, 1983*	*December 6, 1984*
	Gross Capacity (MW)	*880*	*880*
	Net Capacity (MW)	*836*	*842*
	Gross Plant Heat Rate, Btu/kWh	*10234*	*10172*
	Net Plant Heat Rate, Btu/kWh	*10724*	*10661*
	Study Capacity Factor (%)	*(60.28 YTD) 100%*	*(75.83 YTD) 100%*
	Minimum Load (%)	*16.7*	*16.6*
	Elevation, Feet above MSL	*239 ft*	*239 ft*
	Seismic Zone	*2 (built for zone 1)*	*2*
	Foundation Type	*Deep piling*	*Deep piling*
B.	***Boiler Data:***		
	Manufacturer	*Combustion Engineering*	*Combustion Engineering*
	Type	*Tangentially Fired*	*Tangentially Fired*
	Furnace/Unit	*Twin*	*Twin*
	Balanced / Forced Draft?	*Balanced*	*Balanced*
	Boiler Heat Input (MMBtu/hr)	*8967*	*8976*
	Excess Air (%O_2)	*3.0*	*3.0*
	Econo Outlet: Flow (lb/hr)	*9168000*	*9168000*
	O_2 (%)	*3.0*	*3.0*
	Temperature (°F)	*870*	*870*
	Pressure ("wg)		
	AH Gas Outlet: Flow (lb/hr)	*10786000*	*10786000*
	Temp. (°F, des/op)	*280/320*	*280/356*

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ETR_00000803

AH Air Outlet:	Flow (lb/hr)	8628000	8628000
	Temp. (°F, out / in)	780/66	806/101
	Plant / Unit	**Independence 1**	**Independence 2**
C.	***Fan Data:***		
ID Fan Flow:	Design (acfm)	1500*1000	1500*1000
	Testblock (acfm)	1800*1000	1800*1000
Total Press.:	Design ("wg)	15	15
	Testblock ("wg)	18	18
Capacity (%)		50 % ea	50 % ea
Motor HP		6500	6500
Type		Novenco Variax type ASN (1 hub)	Novenco Variax type ASN (1 hub)
Quantity		2	2
Do Fans have spare capacity? (Y/N)		No	No
FD Fan Flow:	Design (acfm)	650*1000	650*1000
	Testblock (acfm)	825*1000	825*1000
Total Press.:	Design ("wg)	18.2	18.2
	Testblock ("wg)	22.5	22.5
Capacity (%)		50% ea	50% ea
Motor HP		4000	4000
Type		Novenco	Novenco
Quantity		2	2
Do Fans have spare capacity? (Y/N)		No – currently derated due to fans	No – currently derated due to fans
D.	***Air Heater:***		
Type / Size		Ljungstrom Trisector 35-VI-96(T)	Ljungstrom Trisector 35-VI-96(T)
Manufacturer		Ljungstrom	Ljungstrom
Number / Unit		2	2
Leakage: (estim.% of Econ FG)		10?	10?
E.	***Burners:***		
Manufacturers		Combustion Engineering	Combustion Engineering
Type		8-1103RP mills & fuel nozzles	8-1103RP mills & fuel nozzles
Fuels Fired		PRB	PRB
Firing Configuration		8 elevations	8 elevations
# Burners / Boiler		64	64
Capacity (MMBtu/hr)		218.75	218.75
Windbox Compartmentalized (Y/N)		Yes	Yes

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ETR_00000804

	Plant / Unit	Independence 1	Independence 2
F.	***Particulate (PM) Control:***		
	Type (ESP/FF)	ESP-Cold side	ESP-Cold side
	Manufacturer / Quantity	*Combustion Engineering Walthers*	*Combustion Engineering Walthers*
	Removal Efficiency (%)	*99.5% design*	*99.5% design*
	Gas Flow (cfm @ °F)	*90 ft/sec @ 262°F*	*90 ft/sec @ 262°F*
	Exit Grain Loading	*0.01 gr/dscf*	*0.01 gr/dscf*
	SCA (ft^2/kACFM)	*542*	*542*
	Fly Ash, (% of total ash)	*75*	*75*
G.	***Fly Ash Collection and Disposal:***		
	Pressure / Vacuum	*Pressure*	*Pressure*
	Capacity (Tons/hr)		
	Fly Ash Silo Capacity	*4000 tons ea*	*4000 tons ea*
	Disposal (offsite/onsite)	*onsite*	*onsite*
	Distance (miles)	*1*	*1*
H.	***Stack:***		
	Height (feet)	*1000*	*1000*
	Liner Material	*A36/ top 50ft 316ss*	*A36/ top 50ft 316ss*
	Liner Diameter @ Top (feet)	*25ft – 8.5in ID*	*25ft – 8.5in ID*
	Condition of Shell / Liner	*Good*	*Good*
I.	***Environmental Output:***	*Load: 864 Gross*	*853 Gross*
	Current SO_2 Outlet (lb/MMBtu)	*0.335*	*0.345*
	Current NOx (lb/MMBtu)	*0.254*	*0.290*
	Current SO_3 (ppm)	*N/A*	*N/A*
	Current Opacity Limit (%)	*20*	*20*
	Current Opacity (%)	*6.5*	*7.4*
	Particulate Limit (lb/MMBtu)	*.04*	*.04*
J.	***Water Supply:***		
	Source of FGD Makeup	*N/A*	*N/A*
	Flow Available (gpm)	*N/A*	*N/A*
	Analysis Available	*N/A*	*N/A*
	Closed /Open Loop Plant Water Bal.	*N/A*	*N/A*
	Discharge Permit Required	*Yes*	*Yes*

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ETR_00000805

Plant / Unit	Independence 1	Independence 2
K. Continuous Emissions Monitoring:		
Available For: NO_x	Yes	Yes
SO_x	Yes	Yes
Opacity	Yes	Yes
L. Coal Unloading:		
Type	Rotary Car	Rotary Car
Unit Train Capability (Y/N)	Yes	Yes
Unloading Rate (Ton/hr)	2500 ton/hr	2500 ton/hr
Coal Storage / Recovery:	Yard/Stacker	Yard/Stacker
Type	Conveyor	Conveyor
Handling Rate (Ton/hr)	1600 @ 450 rpm	1600 @ 450 rpm
Blending Capability	Yes	Yes
M. Boiler Fuels:		
Coal and Fuel Oil	North Antelope (PRB)	North Antelope (PRB)
Analysis, (weight %, wet basis)		
Carbon	47.5	47.5
Hydrogen	3.38	3.38
Sulfur	0.5	0.5
Nitrogen	0.48	0.48
Oxygen	14.31	14.31
Chlorine	0.03	0.03
Ash	5.8	5.8
Moisture	28	28
TOTAL	100	100
HHV, Btu/lb	8794	8785
Natural Gas Available?	No	No
#2 Fuel Oil Usage/Year	517,020 gal (previous 12 mos)	655,876 gal (previous 12 mos)

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ETR_00000806

Economic Criteria for Independence Plant

	Plant / Unit	Independence 1	Independence 2
N.	***Site Specific Cost Data:***		
	Auxiliary Power ($/MWhr)[i]	$34.03/MWh	$34.03/MWh
	Replacement Power ($/MWhr)[i]	$34.03/MWh	$34.03/MWh
	Raw Water ($/1000 gallons)		
	Steam: Quality (low/med)		
	Cost ($/1000 lbs)		
	Waste Disposal ($/ton)		
	Current Coal Cost[ii]	$1.42/MMBtu	$1.42/MMBtu
	Natural Gas Cost[iii]	$5.35/MMBtu	$5.35/MMBtu
	Fuel Oil Cost[iv]	$7.17/MMBtu	$7.17/MMBtu
O.	***Economic Factors:***		
	Date for Reporting Cost Results		
	Remaining Plant Life (years)		
	Minimum Acceptable Return (MAR) (%)		
	AFUDC (%)		
	Fixed Charge Rates:		
	First Year (%)		
	Levelized (%)		
	Escalation Rates:[v]		
	General Inflation Rate (%)	2.0%	2.0%
	O&M Costs (%)	2.0%	2.0%
	Capital Costs (%)	2.0%	2.0%
	Replacement Power (%)	2.0%	2.0%
	Aux Power Costs (%)	2.0%	2.0%
	Fuel Costs (%)	2.0%	2.0%
	Labor Costs (fully burdened rates):		
	Construction ($/hr)		
	Operating ($/hr)		

***All Numbers are in Nominal 2004 $.**
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Numbers can be used by Washington Group International for this study only.
Contains Regulated Information and May Not Be used by Non-Regulated Business Units.

[i] 10 Year Levelized All-In Power Price based on MIDAS June 2004 run 12C-18 for Northern Arkansas Region. Throughout the 10 years there is no capacity price in this region. Also assumes that Auxiliary and Replacement Power would both have to be purchased on the market.

[i] 10 Year Levelized Weighted Average of Delivered Contract and Spot Coal taken from the July 30, 2004 Coal Forecast. We are currently in the process of revising this forecast and our current estimate for Independence is $1.37/MMBtu. However, this forecast is not finalized so we have included the price from our last published forecast.

[i] 10 Year Levelized Price based on August 3, 2004 Corporate Henry Hub Gas POV. These prices include no transportation costs or taxes.

[i] 10 Year Levelized Price of Distillate Fuel Oil #2 Gulf Coast Delivery based on August 13, 2004 Corporate Oil POV. Transportation cost as per conversation with Harrell Wise are $.212/MMBtu for Independence, REDACTED and $.11/MMBtu for White Bluff. Taxes on commodity only are applied to Independence and White Bluff at Arkansas rate of 6% and to REDACTED: Louisiana rate of 3.8%.

[i] All escalations are based on the GDP Deflator taken from the August 17, 2004 Corporate Inflation POV.

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ETR_00000807

REDACTED

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ETR_00000808

REDACTED

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ETR_00000809

REDACTED

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ETR_00000810

REDACTED

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ETR_00000811

REDACTED

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ETR_00000812

[1] All escalations are based on the GDP Deflator taken from the August 17, 2004 Corporate Inflation POV.

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ETR_00000813

White Bluff Plant
Redfield, AR

Plant / Unit	***White Bluff 1***	***White Bluff 2***
A. Unit Information:		
Commercial Operation	*1980*	*1981*
Gross Capacity (MW)	*880*	*880*
Net Capacity (MW)	*815*	*844*
Gross Plant Heat Rate, Btu/kWh	*10317*	*10158*
Net Plant Heat Rate, Btu/kWh	*10,823*	*10,640*
Study Capacity Factor (%)	*62.69 (YTD)*	*75.05 (YTD)*
Minimum Load (%)	*17.1*	*16.6*
Elevation, Feet above MSL	*311 ft*	*311 ft*
Seismic Zone	*2 (built for Zone 1)*	*2 (built for Zone 1)*
Foundation Type	*Deep Piling*	*Deep Piling*
B. Boiler Data:		
Manufacturer	*Combustion Engineering*	*Combustion Engineering*
Type	*Tangentially Fired*	*Tangentially Fired*
Furnace/Unit	*Twin*	*Twin*
Balanced / Forced Draft?	*Balanced*	*Balanced*
Boiler Heat Input (MMBtu/hr)	*8821*	*8959*
Excess Air (%O_2)	*3.0*	*3.0*
Econo Outlet: Flow (lb/hr)	*91670700*	*91670700*
O_2 (%)	*2.8-3.0*	*2.8-3.0*
Temperature (°F)	*870*	*870*
Pressure ("wg)		
AH Gas Outlet: Flow (lb/hr)	*10789000*	*10789000*
Temp. (°F, des/op)	*280/347*	*280/344*
AH Air Outlet: Flow (lb/hr)	*8603148*	*8603148*
Temp. (°F, out / in)	*759/93*	*750/93*
LOI (% limit/Typical)	*0.6/0.3-0.5*	*0.6/0.3-0.5*
C. Fan Data:		
ID Fan Flow: Design (acfm)	*1,500,000*	*1,500,000*
Testblock (acfm)	*1,800,000*	*1,800,000*
Total Press.: Design ("wg)	*15*	*15*
Testblock ("wg)	*18*	*18*
Capacity (%)	*50 % ea*	*50 % ea*
Motor HP	*6500*	*6500*
Type	*Novenco Variax type ASN (1 hub)*	*Novenco Variax type ASN (1 hub)*
Quantity	*2*	*2*
Do Fans have spare capacity? (Y/N)	*No*	*No*

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ETR_00000814

Plant / Unit	White Bluff 1	White Bluff 2
FD Fan Flow: Design (acfm)	650,000	650,000
Testblock (acfm)	825,000	825,000
Total Press.: Design ("wg)	18.2	18.2
Testblock ("wg)	22.5	22.5
Capacity (%)	50% ea	50% ea
Motor HP	4000	4000
Type	Novenco	Novenco
Quantity	2	2
Do Fans have spare capacity? (Y/N)	No	No
D. Air Heater:		
Type / Size	Ljungstrom Trisector 35-VI-96(T)	Ljungstrom Trisector 35-VI-96(T)
Manufacturer	Ljungstrom	Ljungstrom
Number / Unit	2	2
Leakage: (% of Econ FG)	10?	10?
Pressure Drop Clean/Dirty (" w.g.)	2/6	3/8.5
Outlet Temp. (low load °F)	250	250
E. Burners:		
Manufacturers	Combustion Engineering	Combustion Engineering
Type	8-1103RP mills & fuel nozzles	8-1103RP mills & fuel nozzles
Fuels Fired	PRB	PRB
Firing Configuration	8 elevations	8 elevations
# Burners / Boiler	64	64
Capacity (MMBtu/hr) per burner	210.7	210.7
Windbox Compartmentalized (Y/N)	Yes	Yes
F. Particulate (PM) Control:		
Type (ESP/FF)	ESP-Cold side	ESP-Cold side
Manufacturer / Quantity	Combustion Engineering Walther	Combustion Engineering Walther
Removal Efficiency (%)	99.5% design	99.5% design
Gas Flow (cfm @ °F)	90 ft/sec @ 262 deg F	90 ft/sec @ 262°F
Exit Grain Loading	0.01 gr/dscf	0.01 gr/dscf
SCA (ft^2/kACFM)	542	542
Fly Ash, (% of total ash)	75%	75%
G. Fly Ash Collection and Disposal:		
Pressure / Vacuum	Pressure	Pressure
Capacity (Tons/hr)		
Fly Ash Silo Capacity	4000 tons ea	4000 tons ea

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ETR_00000815

Disposal (offsite/onsite)	*Onsite*	*Onsite*
Distance (miles)	*1*	*1*
Plant / Unit	***White Bluff 1***	***White Bluff 2***
H. ***Stack:***		
Height (feet)	*1000*	*1000*
Liner Material	*A36/top 50 ft 316ss*	*A36/top 50 ft 316ss*
Liner Diameter @ Top (feet)	*25ft – 8.5in ID*	*25ft – 8.5in ID*
Condition of Shell / Liner	*Good*	*Good*
I. ***Environmental Output:***		
Current SO_2 Outlet (lb/MMBtu)	*0.69*	*0.68*
Current NOx (lb/MMBtu)	*0.35*	*0.31*
Current SO_3 (ppm)	*NA*	*NA*
Current Opacity Limit (%)	*20*	*20*
Current Opacity (%)	*7.5%*	*12%*
Particulate Limit (lb/MMBtu)	*0.1*	*0.1*
J. ***Water Supply:***		
Source of FGD Makeup	*N/A*	*N/A*
Flow Available (gpm)	*N/A*	*N/A*
Analysis Available	*N/A*	*N/A*
Closed /Open Loop Plant Water Balance	*N/A*	*N/A*
Discharge Permit Required	*Yes*	*Yes*
K. ***Continuous Emissions Monitoring:***		
Available For: NO_x	*Yes*	*Yes*
SO_x	*Yes*	*Yes*
Opacity	*Yes*	*Yes*
L. ***Coal Unloading:***		
Type	*Rotary Car*	*Rotary Car*
Unit Train Capability (Y/N)	*Yes*	*Yes*
Unloading Rate (Ton/hr)	*2500 ton/hr*	*2500 ton/hr*
Coal Storage / Recovery:	*Yard/Stacker*	*Yard/Stacker*
Type	*Conveyor*	*Conveyor*
Handling Rate (Ton/hr)	*1600 @ 450 rpm*	*1600 @ 450 rpm*
Blending Capability	*Yes*	*Yes*

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ETR_00000816

Plant / Unit	White Bluff 1	White Bluff 2
M. Boiler Fuels:		
Coal or ~~Fuel Oil~~	Black Thunder (PRB)	Black Thunder (PRB)
Analysis, (weight %, wet basis)		
Carbon	68.93	68.93
Hydrogen	4.11	4.11
Sulfur	0.41	0.41
Nitrogen	0.78	0.78
Oxygen	18.06	18.06
Chlorine	0.03	0.03
Ash	7.70	7.70
Moisture	NA	NA
TOTAL	100.02	100.02
HHV, Btu/lb	8428	8428
Natural Gas Availability?	N/A	N/A
Fuel Oil Usage per Year? To 6/1/04	868,460.4 Gal (previous 12 mo)	493,357.2 Gal (previous 12 mo)

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ETR_00000817

White Bluff Economic Criteria

Plant / Unit	*White Bluff 1*	*White Bluff 2*
N. ***Site Specific Cost Data:***		
Auxiliary Power ($/MWhr)	$34.03/MWh	$34.03/MWh
Replacement Power ($/MWhr)	$34.03/MWh	$34.03/MWh
Raw Water ($/1000 gallons)		
Steam: Quality (low/med)		
Cost ($/1000 lbs)		
Waste Disposal ($/ton)		
Current Coal Cost	$1.27/MMBtu	$1.27/MMBtu
Natural Gas Cost	$5.35/MMBtu	$5.35/MMBtu
Fuel Oil Cost	$7.07/MMBtu	$7.07/MMBtu
O. ***Economic Factors:***		
Date for Reporting Cost Results		
Remaining Plant Life (years)		
Minimum Acceptable Return (MAR) (%)		
AFUDC (%)		
Fixed Charge Rates:		
First Year (%)		
Levelized (%)		
Escalation Rates:		
General Inflation Rate (%)	2.0%	2.0%
O&M Costs (%)	2.0%	2.0%
Capital Costs (%)	2.0%	2.0%
Replacement Power (%)	2.0%	2.0%
Aux Power Costs (%)	2.0%	2.0%
Fuel Costs (%)	2.0%	2.0%
Labor Costs (fully burdened rates):		
Construction ($/hr)		
Operating ($/hr)		

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ETR_00000819

APPENDIX D – COST ESTIMATE SUMMARY SHEETS FROM IECCOST

The attached tables provide additional detail regarding the cost estimates that were completed for the various emissions control equipment retrofits at Independence, White Bluff, and REDACTED Cost estimates for the individual systems as they might be installed onto each unit are provided, along with tabulations of the control system costs for each plant, where the reagent and solid waste handling systems would be designed to handle the needs of both units at the Independence and White Bluff sites.

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ETR_00000820

Independence 1 FGD		LSFO	LSD/FF	CFB/FF
FGD Technology		LSFO	LSD	LSD
=> Absorber Technology Selection		Absorber	Spray Dryer	CFB Reactor
NOx Control Technology		n/a	n/a	n/a
Hg Removal Technology		n/a	n/a	n/a
Particulate Control Technology		n/a	FF	FF
IEC Technology		n/a	n/a	n/a
Plant's Net Rating	MW	836.0	836.0	836.0
Plant Capacity Factor	%	85%	85%	85%
Boiler Efficiency	%	83.06%	83.06%	83.06%
Plant Location	State	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30
Fuel	Type	N. Antelope	N. Antelope	N. Antelope
Percent Sulfur	%	0.33%	0.33%	0.33%
SO_2 Removal Efficiency:	%	95.0%	92.0%	92.0%
Utility and Chemical Consumption Rates:				
Dibasic Acid	tons/yr	---	---	---
Lime	tons/yr	---	26,745	36,471
Limestone	tons/yr	44,292	---	---
Methane	1000 scf/yr	---	---	---
Steam	tons/yr	---	---	---
Water	1000 gal/yr	372,807	353,174	327,439
Total Power Consumption	kW	9,813	10,387	9,899
Product Production Rates:				
SO_2 Allowances Generated @ $500/ton	tons/yr	16,900	16,100	16,100
Gypsum Byproduct	tons/yr	---	---	---
Solid Waste for Disposal	tons/yr	71,305	59,090	73,846
Capital Costs:				
Cost Basis Year		2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land $	$	$78,707,972	$123,873,728	$106,890,132
	$/kW	$94.15	$148.17	$127.86
First-Year and Levelized Costs:				
First-Year Costs:				
Fixed O&M:	$	$7,267,537	$7,376,825	$6,272,361
	$/kW-Yr	$8.69	$8.82	$7.50
	Mills/KWh	1.17	1.19	1.01
Variable O&M:	$	-$4,282,584	-$2,891,983	-$2,201,032
	$/kW-Yr	-$5.12	-$3.46	-$2.63
	Mills/KWh	-0.69	-0.46	-0.35
Fixed Charges:	$	$5,997,547	$9,439,178	$8,145,028
	$/kW-Yr	$7.17	$11.29	$9.74
	Mills/KWh	0.96	1.52	1.31
Total:	$	$8,982,501	$13,924,020	$12,216,357
	$/kW-Yr	$10.74	$16.66	$14.61
	Mills/KWh	1.44	2.24	1.96

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ETR_00000821

Independence 1 FGD

		LSFO	LSD/FF	CFB/FF
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$10.28	$10.44	$8.87
	Mills/KWh	1.38	1.40	1.19
Variable O&M:	$/kW-Yr	-$6.06	-$4.09	-$3.11
	Mills/KWh	-0.81	-0.55	-0.42
Fixed Charges:	$/kW-Yr	$9.89	$15.56	$13.43
	Mills/KWh	1.33	2.09	1.80
Total:	$/kW-Yr	$14.11	$21.90	$19.19
	Mills/KWh	1.89	2.94	2.58
	$/ton SO2	$496.67	$796.22	$697.41

SO2 Control Costs

		Case 1	Case 2	Case 3
FGD Technology		LSFO	LSD	LSD
Absorber Choice		Absorber	Spray Dryer	CFB Reactor
Total Capital Requirement (TCR)	$	$78,707,972	$80,293,110	$63,309,514
	$/kW	$94.15	$96.04	$75.73
FGD Power Consumption	kW	9,813	5,343	4,855
First-Year Costs:				
Fixed O&M:	$	$7,267,537	$6,103,372	$4,998,908
	$/kW-Yr	$8.69	$7.30	$5.98
	Mills/KWh	1.17	0.98	0.80
	$/ton SO2 removed	$306.03	$265.39	$217.36
Variable O&M:	$	-$4,282,584	-$4,168,953	-$3,478,002
	$/kW-Yr	-$5.12	-$4.99	-$4.16
	Mills/KWh	-0.69	-0.67	-0.56
	$/ton SO2 removed	-$180.34	-$181.28	-$151.23
Fixed Charges:	$	$5,997,547	$6,118,335	$4,824,185
	$/kW-Yr	$7.17	$7.32	$5.77
	Mills/KWh	0.96	0.98	0.77
	$/ton SO2 removed	$252.55	$266.04	$209.77
Total:	$	$8,982,501	$8,052,754	$6,345,091
	$/kW-Yr	$10.74	$9.63	$7.59
	Mills/KWh	1.44	1.29	1.02
	$/ton SO2 removed	$378.24	$350.15	$275.90
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$10.28	$8.64	$7.07
	Mills/KWh	1.38	1.16	0.95
	$/ton SO2 removed	$361.97	$313.90	$257.10
Variable O&M:	$/kW-Yr	-$6.06	-$5.90	-$4.92
	Mills/KWh	-0.81	-0.79	-0.66
	$/ton SO2 removed	-$213.30	-$214.41	-$178.88
Fixed Charges:	$/kW-Yr	$9.89	$10.08	$7.95
	Mills/KWh	1.33	1.35	1.07
	$/ton SO2 removed	$348.00	$366.59	$289.05
Total:	$/kW-Yr	$14.11	$12.82	$10.10
	Mills/KWh	1.89	1.72	1.36
	$/ton SO2 removed	$496.67	$466.08	$367.27

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ETR_00000822

Independence 1 FGD		LSFO	LSD/FF	CFB/FF
Particulate Control Costs		Case 1	Case 2	Case 3
Particulate Control Technology		n/a	FF	FF
Total Capital Requirement (TCR):	$	$0	$43,580,618	$43,580,618
	$/kW	$0.00	$52.13	$52.13
Particulate Control Power Consumption	kW	0	5,044	5,044
First-Year Costs:				
Fixed O&M:	$	$0	$1,273,453	$1,273,453
	$/kW-Yr	$0.00	$1.52	$1.52
	Mills/KWh	0.00	0.20	0.20
Variable O&M:	$	$0	$1,276,970	$1,276,970
	$/kW-Yr	$0.00	$1.53	$1.53
	Mills/KWh	0.00	0.21	0.21
Fixed Charges:	$	$0	$3,320,843	$3,320,843
	$/kW-Yr	$0.00	$3.97	$3.97
	Mills/KWh	0.00	0.53	0.53
Total:	$	$0	$5,871,266	$5,871,266
	$/kW-Yr	$0.00	$7.02	$7.02
	Mills/KWh	0.00	0.94	0.94
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$0.00	$1.80	$1.80
	Mills/KWh	0.00	0.24	0.24
Variable O&M:	$/kW-Yr	$0.00	$1.81	$1.81
	Mills/KWh	0.00	0.24	0.24
Fixed Charges:	$/kW-Yr	$0.00	$5.47	$5.47
	Mills/KWh	0.00	0.74	0.74
Total:	$/kW-Yr	$0.00	$9.08	$9.08
	Mills/KWh	0.00	1.22	1.22

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ETR_00000823

Independence 1 Hg Control

		TOXECON I	TOXECON 1.5	TOXECON II
FGD Technology		n/a	n/a	n/a
=> Absorber Technology Selection		n/a	n/a	n/a
NOx Control Technology		n/a	n/a	n/a
Hg Removal Technology		ACI	ACI	ACI
Particulate Control Technology		FF	FF	n/a
IEC Technology		n/a	n/a	n/a
Plant's Net Rating	MW	836.0	836.0	836.0
Plant Capacity Factor	%	85%	85%	85%
Boiler Efficiency	%	83.06%	83.06%	83.06%
Plant Location	State	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30
Fuel	Type	N. Antelope	N. Antelope	N. Antelope
Percent Sulfur	%	0.33%	0.33%	0.33%
Removal Rates:				
Hg Removal	%	90.0%	90.0%	90.0%
Consumption Rates:				
Activated Carbon	tons/yr	5,237	17,457	17,457
Water	1000 gal/yr	---	---	---
Total Power Consumption	kW	4,126	4,275	213
Product Production Rates:				
Solid Waste for Disposal	tons/yr	5,200	17,500	17,500
Capital Costs:				
Cost Basis Year		2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land				
$	$	$36,376,999	$34,905,515	$10,604,354
	$/kW	$43.51	$41.75	$12.68
First-Year and Levelized Costs:				
First-Year Costs:				
Fixed O&M:	$	$1,362,683	$1,393,662	$759,704
	$/kW-Yr	$1.63	$1.67	$0.91
	Mills/KWh	0.22	0.22	0.12
Variable O&M:	$	$5,952,273	$17,441,524	$16,413,215
	$/kW-Yr	$7.12	$20.86	$19.63
	Mills/KWh	0.96	2.80	2.64
Fixed Charges:	$	$2,771,927	$2,659,800	$808,052
	$/kW-Yr	$3.32	$3.18	$0.97
	Mills/KWh	0.45	0.43	0.13
Total:	$	$10,086,884	$21,494,985	$17,980,971
	$/kW-Yr	$12.07	$25.71	$21.51
	Mills/KWh	1.62	3.45	2.89

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000824

Independence 1 Hg Control

		TOXECON I	TOXECON 1.5	TOXECON II
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$1.93	$1.97	$1.07
	Mills/KWh	0.26	0.26	0.14
Variable O&M:	$/kW-Yr	$8.42	$24.68	$23.22
	Mills/KWh	1.13	3.31	3.12
Fixed Charges:	$/kW-Yr	$4.57	$4.38	$1.33
	Mills/KWh	0.61	0.59	0.18
Total:	$/kW-Yr	$14.92	$31.03	$25.63
	Mills/KWh	2.00	4.17	3.44
	$/lb Hg	*$35,700*	*$73,700*	*$60,600*

Hg Control Costs

		Case 1	Case 2	Case 3
Hg Removal Technology		ACI	ACI	ACI
Total Capital Requirement (TCR):	$	$7,010,499	$13,263,471	$10,604,354
	$/kW	$8.39	$15.87	$12.68
Hg Control Power Consumption	kW	3,644	3,793	213
First-Year Costs:				
Fixed O&M:	$	$502,454	$759,704	$759,704
	$/kW-Yr	$0.60	$0.91	$0.91
	Mills/KWh	0.08	0.12	0.12
	$/lb Hg removed	$1,460	$2,208	$2,208
Variable O&M:	$	$5,830,257	$17,319,507	$16,413,215
	$/kW-Yr	$6.97	$20.72	$19.63
	Mills/KWh	0.94	2.78	2.64
	$/lb Hg removed	$16,944	$50,334	$47,700
Fixed Charges:	$	$534,200	$1,010,677	$808,052
	$/kW-Yr	$0.64	$1.21	$0.97
	Mills/KWh	0.09	0.16	0.13
	$/lb Hg removed	$1,552	$2,937	$2,348
Total:	$	$6,866,911	$19,089,888	$17,980,971
	$/kW-Yr	$8.21	$22.83	$21.51
	Mills/KWh	1.10	3.07	2.89
	$/lb Hg removed	$19,957	$55,479	$52,256
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$0.71	$1.07	$1.07
	Mills/KWh	0.10	0.14	0.14
	$/lb Hg removed	$1,727	$2,611	$2,611
Variable O&M:	$/kW-Yr	$8.25	$24.50	$23.22
	Mills/KWh	1.11	3.29	3.12
	$/lb Hg removed	$20,041	$59,535	$56,419
Fixed Charges:	$/kW-Yr	$0.88	$1.67	$1.33
	Mills/KWh	0.12	0.22	0.18
	$/lb Hg removed	$2,139	$4,047	$3,236
Total:	$/kW-Yr	$9.84	$27.24	$25.63
	Mills/KWh	1.32	3.66	3.44
	$/lb Hg removed	$23,908	$66,193	$62,267

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000825

Independence 1 Hg Control

TOXECON I TOXECON 1.5 TOXECON II

Particulate Control Costs

		Case 1	Case 2	Case 3
Particulate Control Technology		FF	FF	n/a
Total Capital Requirement (TCR):	$	$29,366,500	$21,642,044	$0
	$/kW	$35.13	$25.89	$0.00
Particulate Control Power Consumption	kW	482	482	0
First-Year Costs:				
Fixed O&M:	$	$860,229	$633,957	$0
	$/kW-Yr	$1.03	$0.76	$0.00
	Mills/KWh	0.14	0.10	0.00
Variable O&M:	$	$122,017	$122,017	$0
	$/kW-Yr	$0.15	$0.15	$0.00
	Mills/KWh	0.02	0.02	0.00
Fixed Charges:	$	$2,237,727	$1,649,124	$0
	$/kW-Yr	$2.68	$1.97	$0.00
	Mills/KWh	0.36	0.26	0.00
Total:	$	$3,219,973	$2,405,098	$0
	$/kW-Yr	$3.85	$2.88	$0.00
	Mills/KWh	0.52	0.39	0.00
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$1.22	$0.90	$0.00
	Mills/KWh	0.16	0.12	0.00
Variable O&M:	$/kW-Yr	$0.17	$0.17	$0.00
	Mills/KWh	0.02	0.02	0.00
Fixed Charges:	$/kW-Yr	$3.69	$2.72	$0.00
	Mills/KWh	0.50	0.37	0.00
Total:	$/kW-Yr	$5.08	$3.79	$0.00
	Mills/KWh	0.68	0.51	0.00

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000826

Independence 1 NOx Control		Mobotec	SCR	SNCR	LNB + OFA
FGD Technology		n/a	n/a	n/a	n/a
=> Absorber Technology Selection		n/a	n/a	n/a	n/a
NOx Control Technology		OFA	SCR	SNCR	LNB
Hg Removal Technology		n/a	n/a	n/a	n/a
Particulate Control Technology		n/a	n/a	n/a	n/a
IEC Technology		n/a	n/a	n/a	n/a
Plant's Net Rating	MW	836.0	836.0	836.0	836.0
Plant Capacity Factor	%	85%	85%	85%	85%
Boiler Efficiency	%	83.06%	83.06%	83.06%	83.06%
Plant Location	State	AR	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30	1.30
Fuel	Type	N. Antelope	N. Antelope	N. Antelope	N. Antelope
Percent Sulfur	%	0.33%	0.33%	0.33%	0.33%
Removal Rates:					
SO2 Removal	%	0.0%	0.0%	0.0%	0.0%
NOx Removal	%	40.0%	90.0%	30.0%	35.0%
Hg Removal	%	0.0%	0.0%	0.0%	0.0%
Consumption Rates:					
Ammonia	tons/yr	---	2,825	4,478	---
Methane	1000 scf/yr	---	---	---	---
Steam	tons/yr	---	---	---	---
Urea	tons/yr	---	---	---	---
Water	1000 gal/yr	---	---	---	---
Total Power Consumption	kW	7,013	2,433	46	---
Product Production Rates:					
Solid Waste for Disposal	tons/yr	---	---	---	---
Capital Costs:					
Cost Basis Year		2004	2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land $	$	$14,545,466	$78,432,312	$8,623,935	$20,868,074
	$/kW	$17.40	$93.82	$10.32	$24.96
First-Year and Levelized Costs:					
First-Year Costs:					
Fixed O&M:	$	$57,866	$1,050,823	$129,359	$442,936
	$/kW-Yr	$0.07	$1.26	$0.15	$0.53
	Mills/KWh	0.01	0.17	0.02	0.07
Variable O&M:	$	$1,775,517	$6,669,409	$1,019,048	$0
	$/kW-Yr	$2.12	$7.98	$1.22	$0.00
	Mills/KWh	0.29	1.07	0.16	0.00
Fixed Charges:	$	$1,108,364	$5,976,542	$657,144	$1,590,147
	$/kW-Yr	$1.33	$7.15	$0.79	$1.90
	Mills/KWh	0.18	0.96	0.11	0.26
Total:	$	$2,941,747	$13,696,773	$1,805,551	$2,033,084
	$/kW-Yr	$3.52	$16.38	$2.16	$2.43
	Mills/KWh	0.47	2.20	0.29	0.33

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000827

Independence 1 NOx Control		Mobotec	SCR	SNCR	LNB + OFA
Levelized Current Dollars:					
Fixed O&M:	$/kW-Yr	$0.08	$1.49	$0.18	$0.68
	Mills/KWh	0.01	0.20	0.02	0.09
Variable O&M:	$/kW-Yr	$2.51	$9.44	$1.44	$0.00
	Mills/KWh	0.34	1.27	0.19	0.00
Fixed Charges:	$/kW-Yr	$1.83	$9.85	$1.08	$2.62
	Mills/KWh	0.25	1.32	0.15	0.35
Total:	$/kW-Yr	$4.42	$20.77	$2.71	$3.30
	Mills/KWh	0.59	2.79	0.36	0.44

NOx Control Costs		Case 1	Case 2	Case 3	Case 4
NOx Control Technology		OFA	SCR	SNCR	LNB + OFA
Total Capital Requirement (TCR):	$	$14,545,466	$78,432,312	$8,623,935	$20,868,074
	$/kW	$17.40	$93.82	$10.32	$24.96
NOx Control Power Consumption	kW	7,013	2,433	46	0
First-Year Costs:					
Fixed O&M:	$	$57,866	$1,050,823	$129,359	$442,936
	$/kW-Yr	$0.07	$1.26	$0.15	$0.53
	Mills/KWh	0.01	0.17	0.02	0.07
	$/ton NOx removed	$17	$138	$51	$96
Variable O&M:	$	$1,775,517	$6,669,409	$1,019,048	$0
	$/kW-Yr	$2.12	$7.98	$1.22	$0.00
	Mills/KWh	0.29	1.07	0.16	0.00
	$/ton NOx removed	$524	$874	$401	$0
Fixed Charges:	$	$1,108,364	$5,976,542	$657,144	$1,590,147
	$/kW-Yr	$1.33	$7.15	$0.79	$1.90
	Mills/KWh	0.18	0.96	0.11	0.26
	$/ton NOx removed	$327	$783	$258	$344
Total:	$	$2,941,747	$13,696,773	$1,805,551	$2,033,084
	$/kW-Yr	$3.52	$16.38	$2.16	$2.43
	Mills/KWh	0.47	2.20	0.29	0.33
	$/ton NOx removed	$867	$1,795	$710	$440
Levelized Current Dollars:					
Fixed O&M:	$/kW-Yr	$0.08	$1.49	$0.18	$0.68
	Mills/KWh	0.01	0.20	0.02	0.09
	$/ton NOx removed	$20	$163	$60	$124
Variable O&M:	$/kW-Yr	$2.51	$9.44	$1.44	$0.00
	Mills/KWh	0.34	1.27	0.19	0.00
	$/ton NOx removed	$619	$1,034	$474	$0
Fixed Charges:	$/kW-Yr	$1.83	$9.85	$1.08	$2.62
	Mills/KWh	0.25	1.32	0.15	0.35
	$/ton NOx removed	$450	$1,079	$356	$474
Total:	$/kW-Yr	$4.42	$20.77	$2.71	$3.30
	Mills/KWh	0.59	2.79	0.36	0.44
	$/ton NOx removed	$1,090	$2,276	$890	$598

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000828

Independence 2 FGD		LSFO	LSD/FF	CFB/FF
FGD Technology		LSFO	LSD	LSD
=> Absorber Technology Selection		Absorber	Spray Dryer	CFB Reactor
NOx Control Technology		n/a	n/a	n/a
Hg Removal Technology		n/a	n/a	n/a
Particulate Control Technology		n/a	FF	FF
IEC Technology		n/a	n/a	n/a
Plant's Net Rating	MW	842.0	842.0	842.0
Plant Capacity Factor	%	85%	85%	85%
Boiler Efficiency	%	81.95%	81.95%	81.95%
Plant Location	State	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30
Fuel	Type	N. Antelope	N. Antelope	N. Antelope
Percent Sulfur	%	0.33%	0.33%	0.33%
Removal Rates:				
SO2 Removal	%	95.0%	92.0%	92.0%
Consumption Rates:				
Dibasic Acid	tons/yr	---	---	---
Lime	tons/yr	---	26,779	36,517
Limestone	tons/yr	44,348	---	---
Steam	tons/yr	---	---	---
Water	1000 gal/yr	439,849	429,139	403,418
Total Power Consumption	kW	10,083	10,760	10,272
Product Production Rates:				
SO_2 Allowances Generated @$500/ton	tons/yr	17,200	16,400	16,400
Gypsum Byproduct	tons/yr	---	---	---
Solid Waste for Disposal	tons/yr	71,395	59,165	73,939
Capital Costs:				
Cost Basis Year		2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land	$			
$		$80,715,571	$126,960,902	$109,795,204
	$/kW	$95.86	$150.78	$130.40
First-Year and Levelized Costs:				
First-Year Costs:				
Fixed O&M:	$	$7,398,946	$7,503,827	$6,388,248
	$/kW-Yr	$8.79	$8.91	$7.59
	Mills/KWh	1.18	1.20	1.02
Variable O&M:	$	-$4,334,426	-$2,915,905	-$2,224,192
	$/kW-Yr	-$5.15	-$3.46	-$2.64
	Mills/KWh	-0.69	-0.47	-0.35
Fixed Charges:	$	$6,150,526	$9,674,421	$8,366,395
	$/kW-Yr	$7.30	$11.49	$9.94
	Mills/KWh	0.98	1.54	1.33
Total:	$	$9,215,046	$14,262,342	$12,530,450
	$/kW-Yr	$10.94	$16.94	$14.88
	Mills/KWh	1.47	2.27	2.00

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000829

Independence 2 FGD

		LSFO	LSD/FF	CFB/FF
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$10.39	$10.54	$8.97
	Mills/KWh	1.40	1.42	1.21
Variable O&M:	$/kW-Yr	-$6.09	-$4.10	-$3.12
	Mills/KWh	-0.82	-0.55	-0.42
Fixed Charges:	$/kW-Yr	$10.07	$15.83	$13.69
	Mills/KWh	1.35	2.13	1.84
Total:	$/kW-Yr	$14.37	$22.28	$19.54
	Mills/KWh	1.93	2.99	2.62
		$508.87	$814.59	$714.54

SO_2 Control Costs

		Case 1	Case 2	Case 3
FGD Technology		LSFO	LSD	LSD
Absorber Choice		Absorber	Spray Dryer	CFB Reactor
Total Capital Requirement (TCR)	$	$80,715,571	$81,522,165	$64,356,466
	$/kW	$95.86	$96.82	$76.43
FGD Power Consumption	kW	10,083	5,479	4,991
First-Year Costs:				
Fixed O&M:	$	$7,398,946	$6,176,095	$5,060,516
	$/kW-Yr	$8.79	$7.34	$6.01
	Mills/KWh	1.18	0.99	0.81
	$/ton SO2 removed	$311.17	$268.21	$219.77
Variable O&M:	$	-$4,334,426	-$4,252,899	-$3,561,186
	$/kW-Yr	-$5.15	-$5.05	-$4.23
	Mills/KWh	-0.69	-0.68	-0.57
	$/ton SO2 removed	-$182.29	-$184.69	-$154.65
Fixed Charges:	$	$6,150,526	$6,211,989	$4,903,963
	$/kW-Yr	$7.30	$7.38	$5.82
	Mills/KWh	0.98	0.99	0.78
	$/ton SO2 removed	$258.67	$269.77	$212.97
Total:	$	$9,215,046	$8,135,185	$6,403,292
	$/kW-Yr	$10.94	$9.66	$7.60
	Mills/KWh	1.47	1.30	1.02
	$/ton SO2 removed	$387.55	$353.29	$278.08
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$10.39	$8.68	$7.11
	Mills/KWh	1.40	1.17	0.95
	$/ton SO2 removed	$368.05	$317.24	$259.94
Variable O&M:	$/kW-Yr	-$6.09	-$5.97	-$5.00
	Mills/KWh	-0.82	-0.80	-0.67
	$/ton SO2 removed	-$215.61	-$218.45	-$182.92
Fixed Charges:	$/kW-Yr	$10.07	$10.17	$8.03
	Mills/KWh	1.35	1.37	1.08
	$/ton SO2 removed	$356.43	$371.73	$293.46
Total:	$/kW-Yr	$14.37	$12.87	$10.13
	Mills/KWh	1.93	1.73	1.36
	$/ton SO2 removed	$508.87	$470.52	$370.47

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000830

Independence 2 FGD

		LSFO	LSD/FF	CFB/FF

Particulate Control Costs

		Case 1	Case 2	Case 3
Particulate Control Technology		n/a	FF	FF
Total Capital Requirement (TCR):	$	$0	$45,438,738	$45,438,738
	$/kW	$0.00	$53.97	$53.97
Particulate Control Power Consumption	kW	0	5,281	5,281
First-Year Costs:				
Fixed O&M:	$	$0	$1,327,732	$1,327,732
	$/kW-Yr	$0.00	$1.58	$1.58
	Mills/KWh	0.00	0.21	0.21
Variable O&M:	$	$0	$1,336,994	$1,336,994
	$/kW-Yr	$0.00	$1.59	$1.59
	Mills/KWh	0.00	0.21	0.21
Fixed Charges:	$	$0	$3,462,432	$3,462,432
	$/kW-Yr	$0.00	$4.11	$4.11
	Mills/KWh	0.00	0.55	0.55
Total:	$	$0	$6,127,158	$6,127,158
	$/kW-Yr	$0.00	$7.28	$7.28
	Mills/KWh	0.00	0.98	0.98
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$0.00	$1.87	$1.87
	Mills/KWh	0.00	0.25	0.25
Variable O&M:	$/kW-Yr	$0.00	$1.88	$1.88
	Mills/KWh	0.00	0.25	0.25
Fixed Charges:	$/kW-Yr	$0.00	$5.67	$5.67
	Mills/KWh	0.00	0.76	0.76
Total:	$/kW-Yr	$0.00	$9.41	$9.41
	Mills/KWh	0.00	1.26	1.26

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000831

Independence 2 Hg Control		TOXECON I	TOXECON 1.5	TOXECON II
FGD Technology		n/a	n/a	n/a
=> Absorber Technology Selection		n/a	n/a	n/a
NOx Control Technology		n/a	n/a	n/a
Hg Removal Technology		ACI	ACI	ACI
Particulate Control Technology		FF	FF	n/a
IEC Technology		n/a	n/a	n/a
Plant's Net Rating	MW	842.0	842.0	842.0
Plant Capacity Factor	%	85%	85%	85%
Boiler Efficiency	%	81.95%	81.95%	81.95%
Plant Location	State	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30
Fuel	Type	N. Antelope	N. Antelope	N. Antelope
Percent Sulfur	%	0.33%	0.33%	0.33%
Removal Rates:				
Hg Removal	%	90.0%	90.0%	90.0%
Consumption Rates:				
Activated Carbon	tons/yr	5,486	18,286	18,286
Water	1000 gal/yr	---	---	---
Total Power Consumption	kW	4,319	4,475	223
Product Production Rates:				
Solid Waste for Disposal	tons/yr	5,500	18,300	18,300
Capital Costs:				
Cost Basis Year		2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land $	$	$38,032,412	$35,774,699	$11,016,978
	$/kW	$45.17	$42.49	$13.08
First-Year and Levelized Costs:				
First-Year Costs:				
Fixed O&M:	$	$1,403,092	$1,414,065	$776,471
	$/kW-Yr	$1.67	$1.68	$0.92
	Mills/KWh	0.22	0.23	0.12
Variable O&M:	$	$6,234,244	$18,268,914	$17,192,386
	$/kW-Yr	$7.40	$21.70	$20.42
	Mills/KWh	0.99	2.91	2.74
Fixed Charges:	$	$2,898,070	$2,726,032	$839,494
	$/kW-Yr	$3.44	$3.24	$1.00
	Mills/KWh	0.46	0.43	0.13
Total:	$	$10,535,406	$22,409,012	$18,808,351
	$/kW-Yr	$12.51	$26.61	$22.34
	Mills/KWh	1.68	3.57	3.00

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000832

Independence 2 Hg Control

		TOXECON I	TOXECON 1.5	TOXECON II
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$1.97	$1.99	$1.09
	Mills/KWh	0.26	0.27	0.15
Variable O&M:	$/kW-Yr	$8.76	$25.66	$24.15
	Mills/KWh	1.18	3.45	3.24
Fixed Charges:	$/kW-Yr	$4.74	$4.46	$1.37
	Mills/KWh	0.64	0.60	0.18
Total:	$/kW-Yr	$15.47	$32.11	$26.62
	Mills/KWh	2.08	4.31	3.57
	$/lb Hg	*$37,300*	*$76,700*	*$63,300*

Hg Control Costs

		Case 1	Case 2	Case 3
Hg Removal Technology		ACI	ACI	ACI
Total Capital Requirement (TCR):	$	$7,475,014	$14,008,483	$11,016,978
	$/kW	$8.88	$16.64	$13.08
Hg Control Power Consumption	kW	3,817	3,973	223
First-Year Costs:				
Fixed O&M:	$	$507,979	$776,471	$776,471
	$/kW-Yr	$0.60	$0.92	$0.92
	Mills/KWh	0.08	0.12	0.12
	$/lb Hg removed	$1,474	$2,254	$2,254
Variable O&M:	$	$6,107,032	$18,141,702	$17,192,386
	$/kW-Yr	$7.25	$21.55	$20.42
	Mills/KWh	0.97	2.89	2.74
	$/lb Hg removed	$17,726	$52,657	$49,901
Fixed Charges:	$	$569,596	$1,067,446	$839,494
	$/kW-Yr	$0.68	$1.27	$1.00
	Mills/KWh	0.09	0.17	0.13
	$/lb Hg removed	$1,653	$3,098	$2,437
Total:	$	$7,184,608	$19,985,620	$18,808,351
	$/kW-Yr	$8.53	$23.74	$22.34
	Mills/KWh	1.15	3.19	3.00
	$/lb Hg removed	$20,854	$58,009	$54,592
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$0.71	$1.09	$1.09
	Mills/KWh	0.10	0.15	0.15
	$/lb Hg removed	$1,744	$2,666	$2,666
Variable O&M:	$/kW-Yr	$8.58	$25.48	$24.15
	Mills/KWh	1.15	3.42	3.24
	$/lb Hg removed	$20,966	$62,282	$59,023
Fixed Charges:	$/kW-Yr	$0.93	$1.75	$1.37
	Mills/KWh	0.13	0.23	0.18
	$/lb Hg removed	$2,278	$4,269	$3,358
Total:	$/kW-Yr	$10.22	$28.32	$26.62
	Mills/KWh	1.37	3.80	3.57
	$/lb Hg removed	$24,988	$69,217	$65,047

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000833

Independence 2 Hg Control		TOXECON I	TOXECON 1.5	TOXECON II
Particulate Control Costs		Case 1	Case 2	Case 3
Particulate Control Technology		FF	FF	n/a
Total Capital Requirement (TCR):	$	$30,557,397	$21,766,216	$0
	$/kW	$36.29	$25.85	$0.00
Particulate Control Power Consumption	kW	502	502	0
First-Year Costs:				
Fixed O&M:	$	$895,113	$637,594	$0
	$/kW-Yr	$1.06	$0.76	$0.00
	Mills/KWh	0.14	0.10	0.00
Variable O&M:	$	$127,212	$127,212	$0
	$/kW-Yr	$0.15	$0.15	$0.00
	Mills/KWh	0.02	0.02	0.00
Fixed Charges:	$	$2,328,474	$1,658,586	$0
	$/kW-Yr	$2.77	$1.97	$0.00
	Mills/KWh	0.37	0.26	0.00
Total:	$	$3,350,799	$2,423,392	$0
	$/kW-Yr	$3.98	$2.88	$0.00
	Mills/KWh	0.53	0.39	0.00
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$1.26	$0.90	$0.00
	Mills/KWh	0.17	0.12	0.00
Variable O&M:	$/kW-Yr	$0.18	$0.18	$0.00
	Mills/KWh	0.02	0.02	0.00
Fixed Charges:	$/kW-Yr	$3.81	$2.71	$0.00
	Mills/KWh	0.51	0.36	0.00
Total:	$/kW-Yr	$5.25	$3.79	$0.00
	Mills/KWh	0.70	0.51	0.00

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000834

Independence 2 NOx Control

		Mobotec	SCR	SNCR	LNB + OFA
FGD Technology		n/a	n/a	n/a	n/a
=> Absorber Technology Selection		n/a	n/a	n/a	n/a
NOx Control Technology		OFA	SCR	SNCR	LNB
Hg Removal Technology		n/a	n/a	n/a	n/a
Particulate Control Technology		n/a	n/a	n/a	n/a
IEC Technology		n/a	n/a	n/a	n/a
Plant's Net Rating	MW	842.0	842.0	842.0	842.0
Plant Capacity Factor	%	85%	85%	85%	85%
Boiler Efficiency	%	81.95%	81.95%	81.95%	81.95%
Plant Location	State	AR	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30	1.30
Fuel	Type	N. Antelope	N. Antelope	N. Antelope	N. Antelope
Percent Sulfur	%	0.33%	0.33%	0.33%	0.33%
Removal Rate:					
NOx Removal	%	40.0%	90.0%	30.0%	35.0%
Consumption Rates:					
Ammonia	tons/yr	---	3,229	4,751	---
Methane	1000 scf/yr	---	---	---	---
Steam	tons/yr	---	---	---	---
Urea	tons/yr	---	---	---	---
Water	1000 gal/yr	---	---	---	---
Total Power Consumption	kW	7,064	2,447	48	---
Product Production Rates:					
Solid Waste for Disposal	tons/yr	---	---	---	---
Capital Costs:					
Cost Basis Year		2004	2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land $	$	$14,589,276	$77,575,741	$8,661,277	$20,965,065
	$/kW	$17.33	$92.13	$10.29	$24.90
First-Year and Levelized Costs:					
First-Year Costs:					
Fixed O&M:	$	$58,132	$1,039,054	$129,919	$444,996
	$/kW-Yr	$0.07	$1.23	$0.15	$0.53
	Mills/KWh	0.01	0.17	0.02	0.07
Variable O&M:	$	$1,788,260	$6,781,527	$1,081,147	$0
	$/kW-Yr	$2.12	$8.05	$1.28	$0.00
	Mills/KWh	0.29	1.08	0.17	0.00
Fixed Charges:	$	$1,111,703	$5,911,271	$659,989	$1,597,538
	$/kW-Yr	$1.32	$7.02	$0.78	$1.90
	Mills/KWh	0.18	0.94	0.11	0.25
Total:	$	$2,958,094	$13,731,852	$1,871,055	$2,042,534
	$/kW-Yr	$3.51	$16.31	$2.22	$2.43
	Mills/KWh	0.47	2.19	0.30	0.33

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000835

Independence 2 NOx Control

		Mobotec	SCR	SNCR	LNB + OFA
Levelized Current Dollars:					
Fixed O&M:	$/kW-Yr	$0.08	$1.46	$0.18	$0.68
	Mills/KWh	0.01	0.20	0.02	0.09
Variable O&M:	$/kW-Yr	$2.51	$9.53	$1.52	$0.00
	Mills/KWh	0.34	1.28	0.20	0.00
Fixed Charges:	$/kW-Yr	$1.82	$9.67	$1.08	$2.61
	Mills/KWh	0.24	1.30	0.15	0.35
Total:	$/kW-Yr	$4.41	$20.66	$2.78	$3.30
	Mills/KWh	0.59	2.77	0.37	0.44

NOx Control Costs

		Case 1	Case 2	Case 3	Case 4
NOx Control Technology		OFA	SCR	SNCR	LNB + OFA
Total Capital Requirement (TCR):	$	$14,589,276	$77,575,741	$8,661,277	$20,965,065
	$/kW	$17.33	$92.13	$10.29	$24.90
NOx Control Power Consumption	kW	7,064	2,447	48	0
First-Year Costs:					
Fixed O&M:	$	$58,132	$1,039,054	$129,919	$444,996
	$/kW-Yr	$0.07	$1.23	$0.15	$0.53
	Mills/KWh	0.01	0.17	0.02	0.07
	$/ton NOx removed	$15	$119	$45	$84
Variable O&M:	$	$1,788,260	$6,781,527	$1,081,147	$0
	$/kW-Yr	$2.12	$8.05	$1.28	$0.00
	Mills/KWh	0.29	1.08	0.17	0.00
	$/ton NOx removed	$461	$777	$372	$0
Fixed Charges:	$	$1,111,703	$5,911,271	$659,989	$1,597,538
	$/kW-Yr	$1.32	$7.02	$0.78	$1.90
	Mills/KWh	0.18	0.94	0.11	0.25
	$/ton NOx removed	$287	$678	$227	$302
Total:	$	$2,958,094	$13,731,852	$1,871,055	$2,042,534
	$/kW-Yr	$3.51	$16.31	$2.22	$2.43
	Mills/KWh	0.47	2.19	0.30	0.33
	$/ton NOx removed	$763	$1,574	$644	$387
Levelized Current Dollars:					
Fixed O&M:	$/kW-Yr	$0.08	$1.46	$0.18	$0.68
	Mills/KWh	0.01	0.20	0.02	0.09
	$/ton NOx removed	$18	$141	$53	$109
Variable O&M:	$/kW-Yr	$2.51	$9.53	$1.52	$0.00
	Mills/KWh	0.34	1.28	0.20	0.00
	$/ton NOx removed	$546	$920	$440	$0
Fixed Charges:	$/kW-Yr	$1.82	$9.67	$1.08	$2.61
	Mills/KWh	0.24	1.30	0.15	0.35
	$/ton NOx removed	$395	$934	$313	$417
Total:	$/kW-Yr	$4.41	$20.66	$2.78	$3.30
	Mills/KWh	0.59	2.77	0.37	0.44
	$/ton NOx removed	$958	$1,994	$805	$525

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000836

REDACTED

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD

REDACTED

Confidential Business Information

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ETR_00000838

REDACTED

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD

REDACTED

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000840

REDACTED

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000841

REDACTED

Confidential Business Information

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ETR_00000842

REDACTED

Confidential Business Information

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ETR_00000843

REDACTED

Confidential Business Information

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ETR_00000844

White Bluff 1 FGD

		LSFO	LSD/FF	CFB/FF
FGD Technology		LSFO	LSD	LSD
=> Absorber Technology Selection		Absorber	Spray Dryer	CFB Reactor
NOx Control Technology		n/a	n/a	n/a
Hg Removal Technology		n/a	n/a	n/a
Particulate Control Technology		n/a	FF	FF
IEC Technology		n/a	n/a	n/a
Plant's Net Rating	MW	815.0	815.0	815.0
Plant Capacity Factor	%	85%	85%	85%
Boiler Efficiency	%	82.55%	82.55%	82.55%
Plant Location	State	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30
Fuel	Type	Black Thunder	Black Thunder	Black Thunder
Percent Sulfur	%	0.32%	0.32%	0.32%
Removal Rates:				
SO_2 Removal	%	95.0%	92.0%	92.0%
Consumption Rates:				
Dibasic Acid	tons/yr	---	---	---
Lime	tons/yr	---	25,515	34,793
Limestone	tons/yr	39,538	---	---
Steam	tons/yr	---	---	---
Water	1000 gal/yr	389,248	395,321	370,656
Total Power Consumption	kW	9,412	10,317	9,802
Product Production Rates:				
SO_2 Allowances Generated @ $500/ton	tons/yr	19,700	19,000	19,000
Gypsum Byproduct	tons/yr	---	---	---
Solid Waste for Disposal	tons/yr	65,087	55,625	69,928
Capital Costs:				
Cost Basis Year		2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land $	$	$77,488,329	$122,880,813	$106,382,752
	$/kW	$95.08	$150.77	$130.53
First-Year and Levelized Costs:				
First-Year Costs:				
Fixed O&M:	$	$7,149,600	$7,348,636	$6,244,415
	$/kW-Yr	$8.77	$9.02	$7.66
	Mills/KWh	1.18	1.21	1.03
Variable O&M:	$	-$5,963,406	-$4,477,609	-$3,827,542
	$/kW-Yr	-$7.32	-$5.49	-$4.70
	Mills/KWh	-0.98	-0.74	-0.63
Fixed Charges:	$	$5,904,611	$9,363,518	$8,106,366
	$/kW-Yr	$7.24	$11.49	$9.95
	Mills/KWh	0.97	1.54	1.34
Total:	$	$7,090,804	$12,234,545	$10,523,239
	$/kW-Yr	$8.70	$15.01	$12.91
	Mills/KWh	1.17	2.02	1.73

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000845

White Bluff 1 FGD

		LSFO	LSD/FF	CFB/FF
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$10.38	$10.66	$9.06
	Mills/KWh	1.39	1.43	1.22
Variable O&M:	$/kW-Yr	-$8.65	-$6.50	-$5.55
	Mills/KWh	-1.16	-0.87	-0.75
Fixed Charges:	$/kW-Yr	$9.98	$15.83	$13.71
	Mills/KWh	1.34	2.13	1.84
Total:	$/kW-Yr	$11.70	$20.00	$17.21
	Mills/KWh	1.57	2.69	2.31
		$421.06	$742.86	$639.42

SO_2 Control Costs

		Case 1	Case 2	Case 3
FGD Technology		LSFO	LSD	LSD
Absorber Choice		Absorber	Spray Dryer	CFB Reactor
Total Capital Requirement (TCR)	$	$77,488,329	$79,264,930	$62,766,869
	$/kW	$95.08	$97.26	$77.01
FGD Power Consumption	kW	9,412	5,298	4,783
First-Year Costs:				
Fixed O&M:	$	$7,149,600	$6,074,132	$4,969,911
	$/kW-Yr	$8.77	$7.45	$6.10
	Mills/KWh	1.18	1.00	0.82
	$/ton SO2 removed	$315.58	$276.85	$226.52
Variable O&M:	$	-$5,963,406	-$5,748,313	-$5,098,245
	$/kW-Yr	-$7.32	-$7.05	-$6.26
	Mills/KWh	-0.98	-0.95	-0.84
	$/ton SO2 removed	-$263.22	-$262.00	-$232.37
Fixed Charges:	$	$5,904,611	$6,039,988	$4,782,835
	$/kW-Yr	$7.24	$7.41	$5.87
	Mills/KWh	0.97	1.00	0.79
	$/ton SO2 removed	$260.63	$275.30	$218.00
Total:	$	$7,090,804	$6,365,807	$4,654,501
	$/kW-Yr	$8.70	$7.81	$5.71
	Mills/KWh	1.17	1.05	0.77
	$/ton SO2 removed	$312.98	$290.15	$212.15
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$10.38	$8.82	$7.21
	Mills/KWh	1.39	1.18	0.97
	$/ton SO2 removed	$373.27	$327.46	$267.93
Variable O&M:	$/kW-Yr	-$8.65	-$8.34	-$7.40
	Mills/KWh	-1.16	-1.12	-0.99
	$/ton SO2 removed	-$311.34	-$309.90	-$274.85
Fixed Charges:	$/kW-Yr	$9.98	$10.21	$8.09
	Mills/KWh	1.34	1.37	1.09
	$/ton SO2 removed	$359.13	$379.34	$300.39
Total:	$/kW-Yr	$11.70	$10.68	$7.90
	Mills/KWh	1.57	1.43	1.06
	$/ton SO2 removed	$421.06	$396.91	$293.47

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000846

White Bluff 1 FGD

Particulate Control Costs

		LSFO	LSD/FF	CFB/FF
		Case 1	Case 2	Case 3
Particulate Control Technology		n/a	FF	FF
Total Capital Requirement (TCR):	$	$0	$43,615,883	$43,615,883
	$/kW	$0.00	$53.52	$53.52
Particulate Control Power Consumption	kW	0	5,019	5,019
First-Year Costs:				
Fixed O&M:	$	$0	$1,274,504	$1,274,504
	$/kW-Yr	$0.00	$1.56	$1.56
	Mills/KWh	0.00	0.21	0.21
Variable O&M:	$	$0	$1,270,703	$1,270,703
	$/kW-Yr	$0.00	$1.56	$1.56
	Mills/KWh	0.00	0.21	0.21
Fixed Charges:	$	$0	$3,323,530	$3,323,530
	$/kW-Yr	$0.00	$4.08	$4.08
	Mills/KWh	0.00	0.55	0.55
Total:	$	$0	$5,868,738	$5,868,738
	$/kW-Yr	$0.00	$7.20	$7.20
	Mills/KWh	0.00	0.97	0.97
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$0.00	$1.85	$1.85
	Mills/KWh	0.00	0.25	0.25
Variable O&M:	$/kW-Yr	$0.00	$1.84	$1.84
	Mills/KWh	0.00	0.25	0.25
Fixed Charges:	$/kW-Yr	$0.00	$5.62	$5.62
	Mills/KWh	0.00	0.75	0.75
Total:	$/kW-Yr	$0.00	$9.31	$9.31
	Mills/KWh	0.00	1.25	1.25

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000847

White Bluff 1 Hg Control

		TOXECON I	TOXECON 1.5	TOXECON II
FGD Technology		n/a	n/a	n/a
=> Absorber Technology Selection		n/a	n/a	n/a
NOx Control Technology		n/a	n/a	n/a
Hg Removal Technology		ACI	ACI	ACI
Particulate Control Technology		FF	FF	n/a
IEC Technology		n/a	n/a	n/a
Plant's Net Rating	MW	815.0	815.0	815.0
Plant Capacity Factor	%	85%	85%	85%
Boiler Efficiency	%	82.55%	82.55%	82.55%
Plant Location	State	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30
Fuel	Type	Black Thunder	Black Thunder	Black Thunder
Percent Sulfur	%	0.32%	0.32%	0.32%
Removal Rates:				
Hg Removal	%	90.0%	90.0%	90.0%
Consumption Rates:				
Activated Carbon	tons/yr	5,211	17,371	17,371
Water	1000 gal/yr	---	---	---
Total Power Consumption	kW	4,105	4,254	212
Product Production Rates:				
Solid Waste for Disposal	tons/yr	5,200	17,400	17,400
Capital Costs:				
Cost Basis Year		2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land $	$	$36,467,657	$34,425,930	$10,561,226
	$/kW	$44.75	$42.24	$12.96
First-Year and Levelized Costs:				
First-Year Costs:				
Fixed O&M:	$	$1,365,181	$1,379,138	$757,951
	$/kW-Yr	$1.68	$1.69	$0.93
	Mills/KWh	0.22	0.23	0.12
Variable O&M:	$	$5,922,840	$17,355,158	$16,331,884
	$/kW-Yr	$7.27	$21.29	$20.04
	Mills/KWh	0.98	2.86	2.69
Fixed Charges:	$	$2,778,835	$2,623,256	$804,765
	$/kW-Yr	$3.41	$3.22	$0.99
	Mills/KWh	0.46	0.43	0.13
Total:	$	$10,066,856	$21,357,552	$17,894,600
	$/kW-Yr	$12.35	$26.21	$21.96
	Mills/KWh	1.66	3.52	2.95

Confidential Business Information

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ETR_00000848

5/3 net

White Bluff 1 Hg Control

		TOXECON I	TOXECON 1.5	TOXECON II
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$1.98	$2.00	$1.10
	Mills/KWh	0.27	0.27	0.15
Variable O&M:	$/kW-Yr	$8.60	$25.19	$23.70
	Mills/KWh	1.15	3.38	3.18
Fixed Charges:	$/kW-Yr	$4.70	$4.44	$1.36
	Mills/KWh	0.63	0.60	0.18
Total:	$/kW-Yr	$15.28	$31.62	$26.16
	Mills/KWh	2.05	4.25	3.51
	$/lb Hg	*$26,700*	*$54,800*	*$45,100*

Hg Control Costs

		Case 1	Case 2	Case 3
Hg Removal Technology		ACI	ACI	ACI
Total Capital Requirement (TCR):	$	$6,996,247	$13,219,902	$10,561,226
	$/kW	$8.58	$16.22	$12.96
Hg Control Power Consumption	kW	3,626	3,774	212
First-Year Costs:				
Fixed O&M:	$	$501,876	$757,951	$757,951
	$/kW-Yr	$0.62	$0.93	$0.93
	Mills/KWh	0.08	0.12	0.12
	$/lb Hg removed	$1,092	$1,650	$1,650
Variable O&M:	$	$5,801,367	$17,233,685	$16,331,884
	$/kW-Yr	$7.12	$21.15	$20.04
	Mills/KWh	0.96	2.84	2.69
	$/lb Hg removed	$12,627	$37,509	$35,546
Fixed Charges:	$	$533,114	$1,007,357	$804,765
	$/kW-Yr	$0.65	$1.24	$0.99
	Mills/KWh	0.09	0.17	0.13
	$/lb Hg removed	$1,160	$2,192	$1,752
Total:	$	$6,836,357	$18,998,992	$17,894,600
	$/kW-Yr	$8.39	$23.31	$21.96
	Mills/KWh	1.13	3.13	2.95
	$/lb Hg removed	$14,879	$41,351	$38,947
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$0.73	$1.10	$1.10
	Mills/KWh	0.10	0.15	0.15
	$/lb Hg removed	$1,292	$1,951	$1,951
Variable O&M:	$/kW-Yr	$8.42	$25.01	$23.70
	Mills/KWh	1.13	3.36	3.18
	$/lb Hg removed	$14,935	$44,365	$42,044
Fixed Charges:	$/kW-Yr	$0.90	$1.70	$1.36
	Mills/KWh	0.12	0.23	0.18
	$/lb Hg removed	$1,599	$3,021	$2,414
Total:	$/kW-Yr	$10.05	$27.81	$26.16
	Mills/KWh	1.35	3.74	3.51
	$/lb Hg removed	$17,826	$49,338	$46,409

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000849

White Bluff 1 Hg Control		**TOXECON I**	**TOXECON 1.5**	**TOXECON II**
Particulate Control Costs		Case 1	Case 2	Case 3
Particulate Control Technology		FF	FF	n/a
Total Capital Requirement (TCR):	$	$29,471,410	$21,206,028	$0
	$/kW	$36.16	$26.02	$0.00
Particulate Control Power Consumption	kW	480	480	0
First-Year Costs:				
Fixed O&M:	$	$863,305	$621,187	$0
	$/kW-Yr	$1.06	$0.76	$0.00
	Mills/KWh	0.14	0.10	0.00
Variable O&M:	$	$121,473	$121,473	$0
	$/kW-Yr	$0.15	$0.15	$0.00
	Mills/KWh	0.02	0.02	0.00
Fixed Charges:	$	$2,245,721	$1,615,899	$0
	$/kW-Yr	$2.76	$1.98	$0.00
	Mills/KWh	0.37	0.27	0.00
Total:	$	$3,230,499	$2,358,560	$0
	$/kW-Yr	$3.96	$2.89	$0.00
	Mills/KWh	0.53	0.39	0.00
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$1.25	$0.90	$0.00
	Mills/KWh	0.17	0.12	0.00
Variable O&M:	$/kW-Yr	$0.18	$0.18	$0.00
	Mills/KWh	0.02	0.02	0.00
Fixed Charges:	$/kW-Yr	$3.80	$2.73	$0.00
	Mills/KWh	0.51	0.37	0.00
Total:	$/kW-Yr	$5.23	$3.81	$0.00
	Mills/KWh	0.70	0.51	0.00

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000850

White Bluff 1 NOx Control

		Mobotec	SCR	SNCR	LNB + OFA
FGD Technology		n/a	n/a	n/a	n/a
=> Absorber Technology Selection		n/a	n/a	n/a	n/a
NOx Control Technology		OFA	SCR	SNCR	LNB
Hg Removal Technology		n/a	n/a	n/a	n/a
Particulate Control Technology		n/a	n/a	n/a	n/a
IEC Technology		n/a	n/a	n/a	n/a
Plant's Net Rating	MW	815.0	815.0	815.0	815.0
Plant Capacity Factor	%	85%	85%	85%	85%
Boiler Efficiency	%	82.55%	82.55%	82.55%	82.52%
Plant Location	State	AR	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30	1.30
Fuel	Type	Black Thunder	Black Thunder	Black Thunder	Black Thunder
Percent Sulfur	%	0.32%	0.32%	0.32%	0.32%
Removal Rates:					
NOx Removal	%	40.0%	90.0%	30.0%	35.0%
Consumption Rates:					
Ammonia	tons/yr	---	4,923	5,835	---
Methane	1000 scf/yr	---	---	---	---
Steam	tons/yr	---	---	---	---
Urea	tons/yr	---	---	---	---
Water	1000 gal/yr	---	---	---	---
Total Power Consumption	kW	6,837	2,454	59	---
Product Production Rates:					
Sludge for Disposal	tons/yr	---	---	---	---
Capital Costs:					
Cost Basis Year		2004	2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land $	$	$14,391,696	$76,695,726	$8,699,850	$20,526,658
	$/kW	$17.66	$94.11	$10.67	$25.19
First-Year and Levelized Costs:					
First-Year Costs:					
Fixed O&M:	$	$56,930	$1,030,377	$130,498	$435,685
	$/kW-Yr	$0.07	$1.26	$0.16	$0.53
	Mills/KWh	0.01	0.17	0.02	0.07
Variable O&M:	$	$1,730,917	$6,998,538	$1,327,975	$0
	$/kW-Yr	$2.12	$8.59	$1.63	$0.00
	Mills/KWh	0.29	1.15	0.22	0.00
Fixed Charges:	$	$1,096,647	$5,844,214	$662,929	$1,564,131
	$/kW-Yr	$1.35	$7.17	$0.81	$1.92
	Mills/KWh	0.18	0.96	0.11	0.26
Total:	$	$2,884,494	$13,873,130	$2,121,402	$1,999,816
	$/kW-Yr	$3.54	$17.02	$2.60	$2.45
	Mills/KWh	0.48	2.29	0.35	0.33

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000851

White Bluff 1 NOx Control

		Mobotec	SCR	SNCR	LNB + OFA
Levelized Current Dollars:					
Fixed O&M:	$/kW-Yr	$0.08	$1.50	$0.19	$0.69
	Mills/KWh	0.01	0.20	0.03	0.09
Variable O&M:	$/kW-Yr	$2.51	$10.16	$1.93	$0.00
	Mills/KWh	0.34	1.36	0.26	0.00
Fixed Charges:	$/kW-Yr	$1.85	$9.88	$1.12	$2.64
	Mills/KWh	0.25	1.33	0.15	0.36
Total:	$/kW-Yr	$4.45	$21.53	$3.24	$3.33
	Mills/KWh	0.60	2.89	0.43	0.45

NOx Control Costs

		Case 1	Case 2	Case 3	Case 4
NOx Control Technology		OFA	SCR	SNCR	LNB + OFA
Total Capital Requirement (TCR):	$	$14,391,696	$76,695,726	$8,699,850	$20,526,658
	$/kW	$17.66	$94.11	$10.67	$25.19
NOx Control Power Consumption	kW	6,837	2,454	59	0
First-Year Costs:					
Fixed O&M:	$	$56,930	$1,030,377	$130,498	$435,685
	$/kW-Yr	$0.07	$1.26	$0.16	$0.53
	Mills/KWh	0.01	0.17	0.02	0.07
	$/ton NOx rem.	$10	$77	$29	$54
Variable O&M:	$	$1,730,917	$6,998,538	$1,327,975	$0
	$/kW-Yr	$2.12	$8.59	$1.63	$0.00
	Mills/KWh	0.29	1.15	0.22	0.00
	$/ton NOx rem.	$293	$526	$300	$0
Fixed Charges:	$	$1,096,647	$5,844,214	$662,929	$1,564,131
	$/kW-Yr	$1.35	$7.17	$0.81	$1.92
	Mills/KWh	0.18	0.96	0.11	0.26
	$/ton NOx rem.	$186	$439	$150	$194
Total:	$	$2,884,494	$13,873,130	$2,121,402	$1,999,816
	$/kW-Yr	$3.54	$17.02	$2.60	$2.45
	Mills/KWh	0.48	2.29	0.35	0.33
	$/ton NOx rem.	$488	$1,043	$479	$248
Levelized Current Dollars:					
Fixed O&M:	$/kW-Yr	$0.08	$1.50	$0.19	$0.69
	Mills/KWh	0.01	0.20	0.03	0.09
	$/ton NOx rem.	$11	$92	$35	$70
Variable O&M:	$/kW-Yr	$2.51	$10.16	$1.93	$0.00
	Mills/KWh	0.34	1.36	0.26	0.00
	$/ton NOx rem.	$346	$622	$354	$0
Fixed Charges:	$/kW-Yr	$1.85	$9.88	$1.12	$2.64
	Mills/KWh	0.25	1.33	0.15	0.36
	$/ton NOx rem.	$256	$605	$206	$268
Total:	$/kW-Yr	$4.45	$21.53	$3.24	$3.33
	Mills/KWh	0.60	2.89	0.43	0.45
	$/ton NOx rem.	$613	$1,320	$595	$337

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000852

White Bluff 2 FGD

		LSFO	LSD/FF	CFB/FF
FGD Technology		LSFO	LSD	LSD
=> Absorber Technology Selection		Absorber	Spray Dryer	CFB Reactor
NOx Control Technology		n/a	n/a	n/a
Hg Removal Technology		n/a	n/a	n/a
Particulate Control Technology		n/a	FF	FF
IEC Technology		n/a	n/a	n/a
Plant's Net Rating	MW	844.0	844.0	844.0
Plant Capacity Factor	%	85%	85%	85%
Boiler Efficiency	%	82.64%	82.64%	82.64%
Plant Location	State	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30
Fuel	Type	Black Thunder	Black Thunder	Black Thunder
Percent Sulfur	%	0.32%	0.32%	0.32%
Removal Rates:				
SO2 Removal	%	95.0%	92.0%	92.0%
Consumption Rates:				
Dibasic Acid	tons/yr	---	---	---
Lime	tons/yr	---	25,976	35,422
Limestone	tons/yr	40,253	---	---
Water	1000 gal/yr	396,283	395,926	370,771
Total Power Consumption	kW	9,564	10,437	9,940
Product Production Rates:				
SO_2 Allowances Generated @ $500/ton	tons/yr	22,700	22,000	22,000
Gypsum Byproduct	tons/yr	---	---	---
Solid Waste for Disposal	tons/yr	66,263	56,630	71,192
Capital Costs:				
Cost Basis Year		2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land $	$	$77,830,702	$124,306,725	$107,272,483
	$/kW	$92.22	$147.28	$127.10
First-Year and Levelized Costs:				
First-Year Costs:				
Fixed O&M:	$	$7,262,227	$7,412,366	$6,303,466
	$/kW-Yr	$8.60	$8.78	$7.47
	Mills/KWh	1.16	1.18	1.00
Variable O&M:	$	-$7,366,519	-$5,866,271	-$5,197,523
	$/kW-Yr	-$8.73	-$6.95	-$6.16
	Mills/KWh	-1.17	-0.93	-0.83
Fixed Charges:	$	$5,930,699	$9,472,172	$8,174,163
	$/kW-Yr	$7.03	$11.22	$9.69
	Mills/KWh	0.94	1.51	1.30
Total:	$	$5,826,407	$11,018,268	$9,280,106
	$/kW-Yr	$6.90	$13.05	$11.00
	Mills/KWh	0.93	1.75	1.48

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000853

White Bluff 2 FGD

		LSFO	LSD/FF	CFB/FF
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$10.18	$10.39	$8.83
	Mills/KWh	1.37	1.40	1.19
Variable O&M:	$/kW-Yr	-$10.32	-$8.22	-$7.28
	Mills/KWh	-1.39	-1.10	-0.98
Fixed Charges:	$/kW-Yr	$9.68	$15.46	$13.35
	Mills/KWh	1.30	2.08	1.79
Total:	$/kW-Yr	$9.54	$17.63	$14.90
	Mills/KWh	1.28	2.37	2.00
		$348.97	$666.22	$562.83

SO_2 Control Costs

		Case 1	Case 2	Case 3
FGD Technology		LSFO	LSD	LSD
Absorber Choice		Absorber	Spray Dryer	CFB Reactor
Total Capital Requirement (TCR)	$	$77,830,702	$80,106,808	$63,072,566
	$/kW	$92.22	$94.91	$74.73
FGD Power Consumption	kW	9,564	5,347	4,849
First-Year Costs:				
Fixed O&M:	$	$7,262,227	$6,120,799	$5,011,898
	$/kW-Yr	$8.60	$7.25	$5.94
	Mills/KWh	1.16	0.97	0.80
	$/ton SO2 removed	$314.86	$274.03	$224.38
Variable O&M:	$	-$7,366,519	-$7,154,954	-$6,486,206
	$/kW-Yr	-$8.73	-$8.48	-$7.69
	Mills/KWh	-1.17	-1.14	-1.03
	$/ton SO2 removed	-$319.38	-$320.33	-$290.39
Fixed Charges:	$	$5,930,699	$6,104,139	$4,806,130
	$/kW-Yr	$7.03	$7.23	$5.69
	Mills/KWh	0.94	0.97	0.76
	$/ton SO2 removed	$257.13	$273.28	$215.17
Total:	$	$5,826,407	$5,069,984	$3,331,822
	$/kW-Yr	$6.90	$6.01	$3.95
	Mills/KWh	0.93	0.81	0.53
	$/ton SO2 removed	$252.61	$226.98	$149.16
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$10.18	$8.58	$7.02
	Mills/KWh	1.37	1.15	0.94
	$/ton SO2 removed	$372.42	$324.12	$265.40
Variable O&M:	$/kW-Yr	-$10.32	-$10.03	-$9.09
	Mills/KWh	-1.39	-1.35	-1.22
	$/ton SO2 removed	-$377.77	-$378.88	-$343.47
Fixed Charges:	$/kW-Yr	$9.68	$9.97	$7.85
	Mills/KWh	1.30	1.34	1.05
	$/ton SO2 removed	$354.31	$376.57	$296.49
Total:	$/kW-Yr	$9.54	$8.52	$5.78
	Mills/KWh	1.28	1.14	0.78
	$/ton SO2 removed	$348.97	$321.81	$218.42

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000854

White Bluff 2 FGD		LSFO	LSD/FF	CFB/FF
Particulate Control Costs		Case 1	Case 2	Case 3
Particulate Control Technology		n/a	FF	FF
Total Capital Requirement (TCR):	$	$0	$44,199,916	$44,199,916
	$/kW	$0.00	$52.37	$52.37
Particulate Control Power Consumption	kW	0	5,090	5,090
First-Year Costs:				
Fixed O&M:	$	$0	$1,291,567	$1,291,567
	$/kW-Yr	$0.00	$1.53	$1.53
	Mills/KWh	0.00	0.21	0.21
Variable O&M:	$	$0	$1,288,683	$1,288,683
	$/kW-Yr	$0.00	$1.53	$1.53
	Mills/KWh	0.00	0.21	0.21
Fixed Charges:	$	$0	$3,368,034	$3,368,034
	$/kW-Yr	$0.00	$3.99	$3.99
	Mills/KWh	0.00	0.54	0.54
Total:	$	$0	$5,948,284	$5,948,284
	$/kW-Yr	$0.00	$7.05	$7.05
	Mills/KWh	0.00	0.95	0.95
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$0.00	$1.81	$1.81
	Mills/KWh	0.00	0.24	0.24
Variable O&M:	$/kW-Yr	$0.00	$1.81	$1.81
	Mills/KWh	0.00	0.24	0.24
Fixed Charges:	$/kW-Yr	$0.00	$5.50	$5.50
	Mills/KWh	0.00	0.74	0.74
Total:	$/kW-Yr	$0.00	$9.11	$9.11
	Mills/KWh	0.00	1.22	1.22

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000855

White Bluff 2 Hg Control

		TOXECON I	TOXECON 1.5	TOXECON II
FGD Technology		n/a	n/a	n/a
=> Absorber Technology Selection		n/a	n/a	n/a
NOx Control Technology		n/a	n/a	n/a
Hg Removal Technology		ACI	ACI	ACI
Particulate Control Technology		FF	FF	n/a
IEC Technology		n/a	n/a	n/a
Plant's Net Rating	MW	844.0	844.0	844.0
Plant Capacity Factor	%	85%	85%	85%
Boiler Efficiency	%	82.64%	82.64%	82.64%
Plant Location	State	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30
Fuel	Type	Black Thunder	Black Thunder	Black Thunder
Percent Sulfur	%	0.32%	0.32%	0.32%
Removal Rates:				
Hg Removal	%	90.0%	90.0%	90.0%
Consumption Rates:				
Activated Carbon	tons/yr	5,286	17,619	17,619
Water	1000 gal/yr	---	---	---
Total Power Consumption	kW	4,163	4,314	215
Product Production Rates:				
Solid Waste for Disposal	tons/yr	5,300	17,600	17,600
Capital Costs:				
Cost Basis Year		2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land $	$	$36,892,747	$35,152,445	$10,684,939
	$/kW	$43.71	$41.65	$12.66
First-Year and Levelized Costs:				
First-Year Costs:				
Fixed O&M:	$	$1,378,093	$1,401,788	$762,980
	$/kW-Yr	$1.63	$1.66	$0.90
	Mills/KWh	0.22	0.22	0.12
Variable O&M:	$	$6,007,289	$17,602,954	$16,565,235
	$/kW-Yr	$7.12	$20.86	$19.63
	Mills/KWh	0.96	2.80	2.64
Fixed Charges:	$	$2,811,227	$2,678,616	$814,192
	$/kW-Yr	$3.33	$3.17	$0.96
	Mills/KWh	0.45	0.43	0.13
Total:	$	$10,196,610	$21,683,358	$18,142,407
	$/kW-Yr	$12.08	$25.69	$21.50
	Mills/KWh	1.62	3.45	2.89

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000856

White Bluff 2 Hg Control

		TOXECON I	TOXECON 1.5	TOXECON II
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$1.93	$1.96	$1.07
	Mills/KWh	0.26	0.26	0.14
Variable O&M:	$/kW-Yr	$8.42	$24.67	$23.21
	Mills/KWh	1.13	3.31	3.12
Fixed Charges:	$/kW-Yr	$4.59	$4.37	$1.33
	Mills/KWh	0.62	0.59	0.18
Total:	$/kW-Yr	$14.94	$31.01	$25.61
	Mills/KWh	2.01	4.16	3.44
	$/lb Hg	*$26,600*	*$54,700*	*$45,000*

Hg Control Costs

		Case 1	Case 2	Case 3
Hg Removal Technology		ACI	ACI	ACI
Total Capital Requirement (TCR):	$	$7,037,127	$13,344,879	$10,684,939
	$/kW	$8.34	$15.81	$12.66
Hg Control Power Consumption	kW	3,677	3,828	215
First-Year Costs:				
Fixed O&M:	$	$503,534	$762,980	$762,980
	$/kW-Yr	$0.60	$0.90	$0.90
	Mills/KWh	0.08	0.12	0.12
	$/lb Hg removed	$1,076	$1,631	$1,631
Variable O&M:	$	$5,884,257	$17,479,921	$16,565,235
	$/kW-Yr	$6.97	$20.71	$19.63
	Mills/KWh	0.94	2.78	2.64
	$/lb Hg removed	$12,580	$37,369	$35,414
Fixed Charges:	$	$536,229	$1,016,880	$814,192
	$/kW-Yr	$0.64	$1.20	$0.96
	Mills/KWh	0.09	0.16	0.13
	$/lb Hg removed	$1,146	$2,174	$1,741
Total:	$	$6,924,020	$19,259,781	$18,142,407
	$/kW-Yr	$8.20	$22.82	$21.50
	Mills/KWh	1.10	3.06	2.89
	$/lb Hg removed	$14,803	$41,174	$38,786
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$0.71	$1.07	$1.07
	Mills/KWh	0.09	0.14	0.14
	$/lb Hg removed	$1,273	$1,929	$1,929
Variable O&M:	$/kW-Yr	$8.25	$24.50	$23.21
	Mills/KWh	1.11	3.29	3.12
	$/lb Hg removed	$14,879	$44,201	$41,888
Fixed Charges:	$/kW-Yr	$0.88	$1.66	$1.33
	Mills/KWh	0.12	0.22	0.18
	$/lb Hg removed	$1,580	$2,996	$2,398
Total:	$/kW-Yr	$9.83	$27.23	$25.61
	Mills/KWh	1.32	3.66	3.44
	$/lb Hg removed	$17,732	$49,125	$46,215

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000857

White Bluff 2 Hg Control

Particulate Control Costs

		TOXECON I	TOXECON 1.5	TOXECON II
		Case 1	Case 2	Case 3
Particulate Control Technology		FF	FF	n/a
Total Capital Requirement (TCR):	$	$29,855,620	$21,807,567	$0
	$/kW	$35.37	$25.84	$0.00
Particulate Control Power Consumption	kW	486	486	0
First-Year Costs:				
Fixed O&M:	$	$874,559	$638,808	$0
	$/kW-Yr	$1.04	$0.76	$0.00
	Mills/KWh	0.14	0.10	0.00
Variable O&M:	$	$123,032	$123,032	$0
	$/kW-Yr	$0.15	$0.15	$0.00
	Mills/KWh	0.02	0.02	0.00
Fixed Charges:	$	$2,274,998	$1,661,737	$0
	$/kW-Yr	$2.70	$1.97	$0.00
	Mills/KWh	0.36	0.26	0.00
Total:	$	$3,272,590	$2,423,577	$0
	$/kW-Yr	$3.88	$2.87	$0.00
	Mills/KWh	0.52	0.39	0.00
Levelized Current Dollars:				
Fixed O&M:	$/kW-Yr	$1.23	$0.90	$0.00
	Mills/KWh	0.16	0.12	0.00
Variable O&M:	$/kW-Yr	$0.17	$0.17	$0.00
	Mills/KWh	0.02	0.02	0.00
Fixed Charges:	$/kW-Yr	$3.71	$2.71	$0.00
	Mills/KWh	0.50	0.36	0.00
Total:	$/kW-Yr	$5.11	$3.78	$0.00
	Mills/KWh	0.69	0.51	0.00

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000858

White Bluff 2 NOx Control

		Mobotec	SCR	SNCR	LNB + OFA
FGD Technology		n/a	n/a	n/a	n/a
=> Absorber Technology Selection		n/a	n/a	n/a	n/a
NOx Control Technology		OFA	SCR	SNCR	LNB
Hg Removal Technology		n/a	n/a	n/a	n/a
Particulate Control Technology		n/a	n/a	n/a	n/a
IEC Technology		n/a	n/a	n/a	n/a
Plant's Net Rating	MW	844.0	844.0	844.0	844.0
Plant Capacity Factor	%	85%	85%	85%	85%
Boiler Efficiency	%	82.64%	82.64%	82.64%	82.64%
Plant Location	State	AR	AR	AR	AR
Retrofit Factor		1.30	1.30	1.30	1.30
Fuel	Type	Black Thunder	Black Thunder	Black Thunder	Black Thunder
Percent Sulfur	%	0.32%	0.32%	0.32%	0.32%
Removal Rates:					
NOx Removal	%	40.0%	90.0%	30.0%	35.0%
Consumption Rates:					
Ammonia	tons/yr	---	5,012	5,941	---
Methane	1000 scf/yr	---	---	---	---
Steam	tons/yr	---	---	---	---
Urea	tons/yr	---	---	---	---
Water	1000 gal/yr	---	---	---	---
Total Power Consumption	kW	7,080	2,499	60	---
Product Production Rates:					
Solid Waste for Disposal	tons/yr	---	---	---	---
Capital Costs:					
Cost Basis Year		2004	2004	2004	2004
TCR w/ Market Dem., Power Outage, & Land $	$	$14,603,868	$76,657,622	$8,770,893	$20,997,341
	$/kW	$17.30	$90.83	$10.39	$24.88
First-Year and Levelized Costs:					
First-Year Costs:					
Fixed O&M:	$	$58,220	$1,030,339	$131,563	$445,682
	$/kW-Yr	$0.07	$1.22	$0.16	$0.53
	Mills/KWh	0.01	0.16	0.02	0.07
Variable O&M:	$	$1,792,508	$7,125,022	$1,351,975	$0
	$/kW-Yr	$2.12	$8.44	$1.60	$0.00
	Mills/KWh	0.29	1.13	0.22	0.00
Fixed Charges:	$	$1,112,815	$5,841,311	$668,342	$1,599,997
	$/kW-Yr	$1.32	$6.92	$0.79	$1.90
	Mills/KWh	0.18	0.93	0.11	0.25
Total:	$	$2,963,542	$13,996,672	$2,151,881	$2,045,679
	$/kW-Yr	$3.51	$16.58	$2.55	$2.42
	Mills/KWh	0.47	2.23	0.34	0.33

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000859

White Bluff 2 NOx Control

		Mobotec	SCR	SNCR	LNB + OFA
Levelized Current Dollars:					
Fixed O&M:	$/kW-Yr	$0.08	$1.44	$0.18	$0.68
	Mills/KWh	0.01	0.19	0.02	0.09
Variable O&M:	$/kW-Yr	$2.51	$9.99	$1.89	$0.00
	Mills/KWh	0.34	1.34	0.25	0.00
Fixed Charges:	$/kW-Yr	$1.82	$9.54	$1.09	$2.61
	Mills/KWh	0.24	1.28	0.15	0.35
Total:	$/kW-Yr	$4.41	$20.97	$3.17	$3.29
	Mills/KWh	0.59	2.82	0.43	0.44

NOx Control Costs

		Case 1	Case 2	Case 3	Case 4
NOx Control Technology		OFA	SCR	SNCR	LNB + OFA
Total Capital Requirement (TCR):	$	$14,603,868	$76,657,622	$8,770,893	$20,997,341
	$/kW	$17.30	$90.83	$10.39	$24.88
NOx Control Power Consumption	kW	7,080	2,499	60	0
First-Year Costs:					
Fixed O&M:	$	$58,220	$1,030,339	$131,563	$445,682
	$/kW-Yr	$0.07	$1.22	$0.16	$0.53
	Mills/KWh	0.01	0.16	0.02	0.07
	$/ton NOx removed	$10	$76	$29	$54
Variable O&M:	$	$1,792,508	$7,125,022	$1,351,975	$0
	$/kW-Yr	$2.12	$8.44	$1.60	$0.00
	Mills/KWh	0.29	1.13	0.22	0.00
	$/ton NOx removed	$298	$526	$300	$0
Fixed Charges:	$	$1,112,815	$5,841,311	$668,342	$1,599,997
	$/kW-Yr	$1.32	$6.92	$0.79	$1.90
	Mills/KWh	0.18	0.93	0.11	0.25
	$/ton NOx removed	$185	$431	$148	$195
Total:	$	$2,963,542	$13,996,672	$2,151,881	$2,045,679
	$/kW-Yr	$3.51	$16.58	$2.55	$2.42
	Mills/KWh	0.47	2.23	0.34	0.33
	$/ton NOx removed	$492	$1,034	$477	$249
Levelized Current Dollars:					
Fixed O&M:	$/kW-Yr	$0.08	$1.44	$0.18	$0.68
	Mills/KWh	0.01	0.19	0.02	0.09
	$/ton NOx removed	$11	$90	$34	$70
Variable O&M:	$/kW-Yr	$2.51	$9.99	$1.89	$0.00
	Mills/KWh	0.34	1.34	0.25	0.00
	$/ton NOx removed	$352	$622	$354	$0
Fixed Charges:	$/kW-Yr	$1.82	$9.54	$1.09	$2.61
	Mills/KWh	0.24	1.28	0.15	0.35
	$/ton NOx removed	$255	$594	$204	$269
Total:	$/kW-Yr	$4.41	$20.97	$3.17	$3.29
	Mills/KWh	0.59	2.82	0.43	0.44
	$/ton NOx removed	$619	$1,307	$593	$339

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000860

Independence – Unit 1+ 2 Pollution Control Capital and Levelized Costs

FGD	Capital Cost ($)	Capital Cost ($/kW)	Levelized Cost* ($/ton SO_2)
Wet Limestone with Forced Oxidation	$138,700,000	$83	$402
Lime Spray Dryer with Fabric Filter	$237,200,000	$141	$695
Circulating Fluid Bed with Fabric Filter	$204,200,000	$122	$610

** Independence levelized cost includes a credit for SO_2 removal beyond the SO_2 allowances currently available for each unit. The credit is based on an allowance value of $500/ton. The allowance credit was calculated by subtracting the calculated new emission rate after the retrofit from the allowances held (36,556 tons/yr based on reported allowances for the year 2008 as reported in the EPA Allowances Held Report). The result is the number of allowances that would be available for sale by Entergy.*

NOx Control	Capital Cost ($)	Capital Cost ($/kW)	Levelized Cost* ($/ton NOx)
Mobotec Advanced Overfire Air	$29,150,000	$17	$1020
Selective Catalytic Reduction	$148,400,000	$88	$2,030
Selective Non-catalytic Reduction	$14,100,000	$8	$765
Low NOx Burners with Overfire Air	$41,900,000	$25	$560

**Independence levelized cost does not currently include credit for NOx allowances.*

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000861

White Bluff – Unit 1+2 Pollution Control Capital and Levelized Costs

FGD	Capital Cost ($)	Capital Cost ($/kW)	Levelized Cost* ($/ton SO_2)
Wet Limestone with Forced Oxidation	$136,700,000	$82	$290
Lime Spray Dryer with Fabric Filter	$237,900,000	$143	$610
Circulating Fluid Bed with Fabric Filter	$204,200,000	$123	$510

**White Bluff levelized costs includes a credit for SO_2 removal beyond the SO_2 allowances currently available for each unit. The credit is based on an allowance value of $500/ton. The allowance credit was calculated by subtracting the calculated new emission rate after the retrofit from the allowances held (44,840 tons/yr based on reported allowances for the year 2008 as reported in the EPA Allowances Held Report). The result is the number of allowances that would be available for sale by Entergy.*

NOx Control	Capital Cost ($)	Capital Cost ($/kW)	Levelized Cost* ($/ton NOx)
Mobotec Advanced Overfire Air	$29,000,000	$18	$615
Selective Catalytic Reduction	$145,700,000	$88	$1280
Selective Non-catalytic Reduction	$14,300,000	$9	$550
Low NOx Burners with Overfire Air	$41,500,000	$25	$340

** White Bluff levelized cost does not currently include credit for NOx allowances.*

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000862

Great River Energy Coal Drying Process

GRE Coal Drying Technology - Equipment Cost Calculations

		INDEPENDENCE 1 & 2	REDACTED	WHITE BLUFF 1 & 2
Inflation Rate	%	3%		3%
Capital Cost Current $	%	2%		2%
Capital Cost Constant $	%	0%		0%
Construction Labor Rate	$/hr	$38.00		$38.00
Operating Labor Rate	$/hr	$30.00		$30.00
Power Cost	Mills/kWh	$34		$34
Methane Cost	$/1000 scf	$5		$5
Steam Cost (medium pressure)	$/1000 lbs	$3.50		$3.50
Prime Contractor's Markup (% of equipment)	%	10%		10%
General Facilities (% of installed cost)	%	10%		10%
Engineering Fees (% of installed cost)	%	10%		10%
Process Contingencies (% of installed cost)	%	25%		25%
Project Contingencies (% of installed cost)	%	15%		15%
Levelized Fixed Charge Rate (FCR)	%	10.5%		10.5%
Discount Rate (MAR)	%	7.5%		7.5%
AFUDC Rate	%	5.1%		5.1%
Construction Period	years	3		3
First Year Fixed Charge Rate	%	7.6%		7.6%
Service Life	years	20		20
Discount Rate - Constant $	%	4.4%		4.4%
Levelized Fixed Charged Rate - Constant $	%	10.5%		10.5%
Escalation Rates:				
Consumables - current $	%	2.0%		2.0%
Consumables - constant $	%	0.0%		0.0%
Capital - current $	%	2.0%		2.0%
Capital constant $	%	0.0%		0.0%
Power and Steam - current $	%	2.0%		2.0%
Power and Steam - constant $	%	0.3%		0.3%
Market demand - current $	%	0.0%		0.0%
Royalties Adjustment (% of process capital)	%	0.5%		0.5%
Fabric Filter Bag Life	years	6		6
Solids Disposal Cost	$/ton	$2		$2
Feedstock Coal Price, delivered	$/ton	$25		$22
Reagent Storage	days	30		30

Confidential Business Information

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ETR_00000863

Maintenance (% of installed cost)	%	5%		5%
SO2 Allowance Value	$/ton	$500		$500

		INDEPENDENCE 1 & 2	REDACTED	WHITE BLUFF 1 & 2
[redacted]				[redacted]
Operating Quantity:				
Coal Supply Conveyor		3		3
Fluidized Bed Coal Dryer		1		1
Product Screw Conveyor		3		3
Processed Coal Conveyor		3		3
Fabric Filter		1		1
Process Air Fans		2		2
Process Air Ductwork		1		1
Circulating Water Pump		2		2
Instrument/Plant Air Compressor		2		2
Onsite Electrical Power Hookups		1		1
Total Installed Quantity:				
Coal Supply Conveyor		4		4
Fluidized Bed Coal Dryer		1		1
Product Screw Conveyor		4		4
Processed Coal Conveyor		4		4
Fabric Filter		1		1
Process Air Fans		2		2
Process Air Ductwork		1		1
Circulating Water Pump		3		3
Instrument/Plant Air Compressor		2		2
Onsite Electrical Power Hookups		1		1
[redacted]				[redacted]
Flow Capacity/Sizing Criteria:				
Coal Supply Conveyor	TPH Solids	339.8		337.2
Fluidized Bed Coal Dryer	TPH Feed	1019.5		1011.6
Product Screw Conveyor	TPH Solids	316.9		314.2
Off-Gas	K ACFM	2039.0		2023.2
Processed Coal Conveyor	TPH Solids	316.9		314.2
Fabric Filter	K ACFM	2039.0		2023.2
Process Air Fans	K ACFM	1019.5		1011.6
Process Air Ductwork	K ACFM	2039.0		2023.2
Circulating Water Pump	gpm	2621.9		2592.2
Instrument/Plant Air Compressor	K SCFM	2796.7		2765.0

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000864

Onsite Electrical Power Hookups	MW	1678.0	REDACTED	1659.0
Horsepower Calculations:				
Coal Supply Conveyor	Oper. HP	24.0		24.0
Product Screw Conveyor	Oper. HP	24.0		24.0
Processed Coal Conveyor	Oper. HP	24.0		24.0
Fabric Filter	Oper. HP	293.1		291.1
Process Air Fans	Oper. HP	4812.0		4774.7
	T.B. HP	6000.0		6000.0
Circulating Water Pump	Oper. HP	435.1		430.2
	T.B. HP	500.0		500.0
Instrument/Plant Air Compressor	Oper. HP	96.4		95.3
Total =	HP	11708.6		11663.3
Total =	kW	8731.1		8697.3
Material Costs	1999	2004		2004
Coal Supply Conveyor	$	$143,219		$142,515
Fluidized Bed Coal Dryer	$	$1,660,013		$1,653,427
Product Screw Conveyor	$	$137,081		$136,369
Processed Coal Conveyor	$	$137,081		$136,369
Fabric Filter	$	$5,380,500		$5,344,568
Process Air Fans	$	$1,484,740		$1,484,740
Process Air Ductwork	$	$1,289,105		$1,284,100
Circulating Water Pump	$	$56,547		$56,547
Instrument/Plant Air Compressor	$	$117,720		$117,720
Onsite Electrical Power Hookups	$	$1,817,547		$1,811,348
TOTAL	$	$12,223,552		$12,167,703
Total Material Costs				
Coal Supply Conveyor	$	$190,958		$190,020
Fluidized Bed Coal Dryer	$	$1,660,013		$1,653,427
Product Screw Conveyor	$	$182,775		$181,826
Processed Coal Conveyor	$	$182,775		$181,826
Fabric Filter	$	$5,380,500		$5,344,568
Process Air Fans	$	$1,484,740		$1,484,740
Process Air Ductwork	$	$1,289,105		$1,284,100
Circulating Water Pump	$	$84,820		$84,820
Instrument/Plant Air Compressor	$	$117,720		$117,720
Onsite Electrical Power Hookups	$	$1,817,547		$1,811,348
TOTAL	$	$12,390,953		$12,334,395

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000865

Installation Factors:				
Coal Supply Conveyor		1.26	REDACTED	1.26
Fluidized Bed Coal Dryer		2.20		2.20
Product Screw Conveyor		1.26		1.26
Processed Coal Conveyor		1.26		1.26
Fabric Filter		1.56		1.56
Process Air Fans		1.33		1.33
Process Air Ductwork		1.10		1.10
Circulating Water Pump		5.00		5.00
Instrument/Plant Air Compressor		3.02		3.01
Onsite Electrical Power Hookups		1.09		1.09
Total Installed Cost:				
Coal Supply Conveyor	$	$239,854		$238,836
Fluidized Bed Coal Dryer	$	$3,656,864		$3,643,407
Product Screw Conveyor	$	$230,940		$229,902
Processed Coal Conveyor	$	$230,940		$229,902
Fabric Filter	$	$8,393,580		$8,337,526
Process Air Fans	$	$1,967,475		$1,967,415
Process Air Ductwork	$	$1,418,015		$1,412,510
Circulating Water Pump	$	$424,101		$424,101
Instrument/Plant Air Compressor	$	$355,466		$354,710
Onsite Electrical Power Hookups	$	$1,979,968		$1,973,215
TOTAL:	$	$18,897,203		$18,811,525
Retrofit Factor Summary				
Retrofit Factors				
State		1		1
Seismic		1		1
Congestion		1		1
Undergrounds		1		1
Soil - Geotechnical		1		1
Miscellaneous		1.3		1.3
RETROFIT FACTOR		1.3		1.3
Total Process Capital				
Coal Supply Conveyor	$	$311,810		$310,487
Fluidized Bed Coal Dryer	$	$4,753,923		$4,736,429
Product Screw Conveyor	$	$300,222		$298,873
Processed Coal Conveyor	$	$300,222		$298,873

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000866

Fabric Filter	$	$10,911,654	REDACTED	$10,838,783
Process Air Fans	$	$2,557,718		$2,557,640
Process Air Ductwork	$	$1,843,420		$1,836,264
Circulating Water Pump	$	$551,331		$551,331
Instrument/Plant Air Compressor	$	$462,106		$461,124
Onsite Electrical Power Hookups	$	$2,573,958		$2,565,180
TOTAL:	$	$24,566,364		$24,454,982

Capital Cost Summary

Total Process Capital			
TOTAL:	$	$24,566,364	$24,454,982
General Facilities			
TOTAL:	$	$2,456,636	$2,445,498
Engineering and Home Office Fees			
TOTAL:	$	$2,456,636	$2,445,498
Process Contingencies			
TOTAL:	$	$6,141,591	$6,113,746
Project Contingencies			
TOTAL:	$	$3,684,955	$3,668,247
Total Plant Cost			
TOTAL:	$	$39,306,183	$39,127,972
	$/kW	$23.42	$23.59
	Mills/kWh	0.33	0.33
Total Cash Expended (TCE)	$	$38,540,511	$38,365,771
Allowance for Funds During Construction (AFDC)	$	$1,968,454	$1,959,529
Total Plant Investment (TPI)	$	$40,508,965	$40,325,300
Preproduction Costs	$	$684,108	$726,109
Inventory Capital	$	$0	$0
Initial Catalyst and Chemicals	$	$0	$2
Prepaid Royalties	$	$122,832	$122,275
Total Capital Requirement (TCR)	$	$41,315,904	$41,173,685
Market Demand Escalation	$	$0	$0
Power Outage Penalty	$	$0	$0
Land Cost	$	$0	$0
TCR (w/Market Dem, Power Outage, and Land $)	$	**$41,315,904**	**$41,173,685**
	$/kW	$24.62	$24.82
	Mills/kWh	0.35	0.35

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000867

			REDACTED
Maintenance Cost By Area			
First Year Maintenance Labor Cost			
TOTAL:	$	$786,124	$782,559
First Year Maintenance Material Cost			
TOTAL:	$	$1,179,185	$1,173,839
Total First Year Maintenance Cost			
TOTAL:	$	$1,965,309	$1,956,399

Operating Cost Summary			
Important Operating Parameters			
Fines Disposal	tons/hr	10.2	10.1
Total APC Power Consumption	kW	8,731	8,697
Reduced ID Fan/Pulverizer Credit	kW	910	910
Reduced Coal Usage (Efficiency Credit)	tons/hr	20	20
SO2 Reduction Credit	tons/hr	0.470	0.453
Fixed O&M Costs			
Number of Operators		1	1
Operating Labor Cost	$/yr	$62,400	$62,400
Maintenance Labor and Materials Cost	$/yr	$1,965,309	$1,956,399
Administrative and Support Labor	$/yr	$254,557	$253,488
TOTAL first year fixed O&M cost	$/yr	$2,282,266	$2,272,286
Variable Operating Costs			
SO2 Credit	$/yr	-$1,751,039	-$1,684,713
Periodic Replacement - FF Bags	$/yr	$113,278	$112,400
Fines Disposal	$/yr	$151,824	$150,647
Efficiency Credit	$/yr	-$3,719,943	-$3,301,292
Reduced ID Fan/Pulverizer Power Credit	$/yr	-$230,379	-$230,379
Additional Power Cost	$/yr	$2,210,401	$2,201,840
Total First Year Variable Cost	$/yr	($3,225,858)	($2,751,497)

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000868

GRE Coal Drying Technology - Combustion Info

		INDEPENDENCE 1 & 2	REDACTED	WHITE BLUFF 1 & 2
Boiler & Plant Data Summary				
Coal Flow Rates				
Btu Input Rate to Boiler	MMBtu/hr	17,943.00		17,804.40
Coal Input Rate to Boiler	tons/hr	1019.500		1011.600
Coal Input Rate to Boiler	lbs/MMBtu	113.64		113.60
MMBtu/Hr Out of Boiler	MMBtu/hr	14,908.00		14,701.60
Total Gross Rating	MW	1,760		1,760
Total Net Rating (less auxiliary power)	MW	1,678		1,659
Plant Capacity Factor	%	85%		85%
Ambient Absolute Pressure	in Hg	29.92		29.92
SO2 Removal Efficiency	%	7.00%		7.00%
NOx Removal Efficiency	%	0.00%		0.00%
Hg Removal Efficiency	%	7.00%		7.00%
Outlet Particulate Emissions Limit	lb/MMBTU	0.04		0.03
Process Efficiency	%	100%		100%
Dryer Temperature	deg F	302		302
Mercury Concentration in Feedstock Coal	ppm	0.07		0.09
Fabric Filter Air to Cloth Ratio	ACFM/ft^2	6.00		6.00
Efficiency Increase	%	2%		2%

Processed Coal Calcs

Index Number	1	2	3
Coal Name	N. Antelope	Black Thunder	Black Thunder
COAL ULTIMATE ANALYSIS (ASTM, as received, weight percent)			
Moisture	27.05%	27.30%	27.30%
Carbon	51.76%	50.97%	50.97%
Hydrogen	3.67%	3.50%	3.50%
Nitrogen	0.90%	0.60%	0.60%
Chlorine	0.05%	0.01%	0.01%
Sulfur	0.33%	0.32%	0.32%
Ash	4.40%	5.30%	5.30%
Oxygen	11.84%	12.00%	12.00%
TOTAL	100.00%	100.00%	100.00%

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000869

Mott Spooner HHV (Btu/lb)		8,800	8,800	8,800
		1019	298	1012
Lbs per 100 lb Coal				
Moisture		27.05	27.3	27.3
Carbon		51.76	50.97	50.97
Hydrogen		3.67	3.5	3.5
Nitrogen		0.9	0.6	0.6
Chlorine		0.05	0.01	0.01
Sulfur		0.33	0.32	0.32
Ash		4.4	5.3	5.3
Oxygen		11.84	12	12
TOTAL		100	100	100
After Processing, lbs per 100 lb coal				
Moisture		20.29	20.48	20.48
Carbon		51.76	50.97	50.97
Hydrogen		3.67	3.5	3.5
Nitrogen		0.9	0.6	0.6
Chlorine		0.05	0.01	0.01
Sulfur		0.33	0.32	0.32
Ash		4.4	5.3	5.3
Oxygen		11.84	12	12
TOTAL		93.24	93.18	93.18
Processed Coal Ultimate Analysis				
Moisture		21.76%	21.97%	21.97%
Carbon		55.51%	54.70%	54.70%
Hydrogen		3.94%	3.76%	3.76%
Nitrogen		0.97%	0.64%	0.64%
Chlorine		0.05%	0.01%	0.01%
Sulfur		0.35%	0.34%	0.34%
Ash		4.72%	5.69%	5.69%
Oxygen		12.70%	12.88%	12.88%
TOTAL		100.00%	100.00%	100.00%
Mott Spooner HHV (Btu/lb)		9,647	9,408	9,408
New Required Coal Flow (Processed Coal)	lb/hr	1859947	558007	1892378
	ton/hr	930	279	946

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ETR_00000870

GRE Coal Processing Technology - Cost Summary and Consumption Rates/Product Production Rates

First Year and Levelized Cost Breakdown

		INDEPENDENCE 1 & 2	REDACTED	WHITE BLUFF 1 & 2
Total Capital Requirement (TCR)	$	$41,315,904		$41,173,685
	$/kW	**$24.62**		**$24.82**
First Year Costs				
Fixed O&M	$	$2,282,266		$2,272,286
	$/kW-yr	$1.36		$1.37
	Mills/kWh	0.18		0.18
Variable O&M	$	($3,225,858)		($2,751,497)
	$/kW-yr	($1.92)		($1.66)
	Mills/kWh	(0.26)		(0.22)
Fixed Charges	$	$3,148,272		$3,137,435
	$/kW-yr	$1.88		$1.89
	Mills/kWh	0.25		0.25
Total	$	$2,204,680		$2,658,224
	$/kW-yr	$1.31		$1.60
	Mills/kWh	0.18		0.22
Levelized Current Dollars				
Fixed O&M	$/kW-yr	$1.61		$1.62
	Mills/kWh	0.22		0.22
Variable O&M	$/kW-yr	($2.27)		($1.96)
	Mills/kWh	(0.31)		(0.26)
Fixed Charges	$/kW-yr	$2.59		$2.61
	Mills/kWh	0.35		0.35
Total	$/kW-yr	$1.92		$2.26
	Mills/kWh	$0.26		$0.30
Levelized Constant Dollars				
Fixed O&M	$/kW-yr	$1.36		$1.37
	Mills/kWh	0.18		0.18
Variable O&M	$/kW-yr	($1.89)		($1.63)
	Mills/kWh	(0.26)		(0.23)
Fixed Charges	$/kW-yr	$2.59		$2.61
	Mills/kWh	0.35		0.35
Total	$/kW-yr	$2.06		$2.35
	Mills/kWh	0.27		0.31

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ETR_00000871

APPENDIX E - Levelized and Operating Cost Breakdowns for Each Unit

Independence 1 Levelized and First-Year O&M Cost Breakdown

Wet Limestone with Forced Oxidation:

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$2,863,519	$3,386,969
Maintenance Labor and Materials Cost	$/yr	$3,165,145	$3,743,732
Administrative and Support Labor	$/yr	$1,238,873	$1,465,339
TOTAL First Year Fixed O&M Cost	$/yr	$7,267,537	$8,596,040
Variable Operating Costs			
Reagent Costs	$/yr	$544,798	$644,386
Sludge Disposal Cost for FGD System	$/yr	$1,140,879	$1,349,431
Credit for Byproduct	$/yr	$0	$0
Dibasic Acid Costs	$/yr	$0	$0
SO2 Credit	$/yr	($8,452,556)	($9,997,680)
Steam Costs	$/yr	$0	$0
Water Cost - Blowdown Only	$/yr	$0	$0
Additional Power Costs	$/yr	$2,484,296	$2,938,424
TOTAL First Year Variable Cost	$/yr	($4,282,583)	($5,065,439)

Lime Spray Dryer with Fabric Filter

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$1,763,878	$2,086,314
Maintenance Labor and Materials Cost	$/yr	$4,675,534	$5,530,219
Administrative and Support Labor	$/yr	$937,413	$1,108,772
TOTAL First Year Fixed O&M Cost	$/yr	$7,376,825	$8,725,305
Variable Operating Costs			
Reagent Costs	$/yr	$1,604,723	$1,898,065
Sludge Disposal Cost for FGD System	$/yr	$945,445	$1,118,272
Credit for Byproduct	$/yr	$0	$0
SO2 Credits	$/yr	($8,077,590)	($9,554,170)
Steam Costs	$/yr	$0	$0
Water Cost - Fresh	$/yr	$5,865	$6,937
Water Cost - Blowdown	$/yr	$0	$0
FF Bags	$/yr	$587,057	$694,371
Additional Power Costs	$/yr	$2,629,574	$3,110,259
TOTAL First Year Variable Cost	$/yr	($2,304,926)	($2,726,267)

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ETR_00000872

Circulating Fluid Bed with Fabric Filter

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$1,763,878	$2,086,314
Maintenance Labor and Materials Cost	$/yr	$3,689,405	$4,363,826
Administrative and Support Labor	$/yr	$819,078	$968,805
TOTAL First Year Fixed O&M Cost	$/yr	$6,272,361	$7,418,945
Variable Operating Costs			
Reagent Costs	$/yr	$2,188,258	$2,588,271
Sludge Disposal Cost for FGD System	$/yr	$1,181,540	$1,397,525
Credit for Byproduct	$/yr	$0	$0
SO2 Credits	$/yr	($8,077,590)	($9,554,170)
Steam Costs	$/yr	$0	$0
Water Cost - Fresh	$/yr	$569	$673
Water Cost - Blowdown	$/yr	$0	$0
FF Bags	$/yr	$587,057	$694,371
Additional Power Costs	$/yr	$2,506,190	$2,960,160
TOTAL First Year Variable Cost	$/yr	($1,613,976)	($1,913,171)

Mobotec Advanced OFA

		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$57,866	$68,443
TOTAL First Year Fixed O&M Cost	$/yr	$57,866	$68,443
Variable Operating Costs			
ROFA Fan Power	$/yr	$1,775,517	$2,100,081
TOTAL First Year Variable Cost	$/yr	$1,775,517	$2,100,081

Selective Catalytic Reduction

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$174,734	$206,675
Maintenance Labor and Materials Cost	$/yr	$876,089	$1,036,237
TOTAL First Year Fixed O&M Cost	$/yr	$1,050,823	$1,242,913
Variable Operating Costs			
Reagent	$/yr	$635,529	$751,703
Catalyst Replacement	$/yr	$5,338,707	$6,314,620
Catalyst Disposal	$/yr	$4,128	$4,882
Electricity	$/yr	$615,959	$728,556
High-dust SCR Steam	$/yr	$75,086	$88,812

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ETR_00000873

NOx Credit	$/yr	$0	$0
Total First Year Variable O&M Costs	$/yr	$6,669,409	$7,888,574

Selective Noncatalytic Reduction

		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$113,455	$134,195
TOTAL First Year Fixed O&M Cost	$/yr	$113,455	$134,195
Variable Operating Costs			
Reagent Cost	$/yr	$1,007,505	$1,191,677
Water Cost	$/yr	$0	$0
Additional Power Costs	$/yr	$11,543	$13,653
NOx Credit	$/yr	$0	$0
Total First Year Variable O&M Costs	$/yr	$1,019,048	$1,205,330

Low NOx Burners with Overfire Air

		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$442,936	$523,905
TOTAL First Year Fixed O&M Cost	$/yr	$442,936	$523,905
Variable Operating Costs			
TOTAL First Year Variable Cost	$/yr	$0	$0

TOXECON I

		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$1,362,683	$1,611,781
TOTAL First Year Fixed O&M Cost	$/yr	$1,362,683	$1,611,781
Variable Operating Costs			
Annual Sorbent Cost	$/yr	$4,751,027	$5,619,513
Sorbent Disposal Cost	$/yr	$10,474	$12,389
Additional Power Cost	$/yr	$1,044,463	$1,235,390
FF Bags	$/yr	$342,450	$405,049
Total First Year Variable O&M Costs	$/yr	$6,148,413	$7,272,341

TOXECON I.5

	First Year	Levelized
Fixed O&M Costs		

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ETR_00000874

Maintenance Labor and Materials Cost	$/yr	$1,393,662	$1,648,422
TOTAL First Year Fixed O&M Cost	$/yr	$1,393,662	$1,648,422
Variable Operating Costs			
Annual Sorbent Cost	$/yr	$15,836,757	$18,731,709
Sorbent Disposal Cost	$/yr	$34,914	$41,296
Additional Power Cost	$/yr	$1,082,154	$1,279,971
FF Bags	$/yr	$114,150	$135,016
Total First Year Variable O&M Costs	$/yr	$17,067,975	$20,187,993

TOXECON II

		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$759,704	$898,578
TOTAL First Year Fixed O&M Cost	$/yr	$759,704	$898,578
Variable Operating Costs			
Annual Sorbent Cost	$/yr	$15,836,757	$18,731,709
Sorbent Disposal Cost	$/yr	$34,914	$41,296
Additional Power Cost	$/yr	$53,845	$63,688
Total First Year Variable O&M Costs	$/yr	$15,925,516	$18,836,694

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000875

Independence 2 Levelized and First-Year O&M Cost Breakdown

Wet Limestone with Forced Oxidation:

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$2,877,869	$3,403,943
Maintenance Labor and Materials Cost	$/yr	$3,265,818	$3,862,808
Administrative and Support Labor	$/yr	$1,255,259	$1,484,720
TOTAL First Year Fixed O&M Cost	$/yr	$7,398,946	$8,751,470
Variable Operating Costs			
Reagent Costs	$/yr	$545,484	$645,198
Sludge Disposal Cost for FGD System	$/yr	$1,142,317	$1,351,132
Credit for Byproduct	$/yr	$0	$0
Dibasic Acid Costs	$/yr	$0	$0
SO2 Credit	$/yr	($8,574,768)	($10,142,233)
Steam Costs	$/yr	$0	$0
Water Cost - Blowdown Only	$/yr	$0	$0
Additional Power Costs	$/yr	$2,552,541	$3,019,145
TOTAL First Year Variable Cost	$/yr	($4,334,426)	($5,126,757)

Lime Spray Dryer with Fabric Filter

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$1,767,407	$2,090,489
Maintenance Labor and Materials Cost	$/yr	$4,790,647	$5,666,376
Administrative and Support Labor	$/yr	$945,772	$1,118,659
TOTAL First Year Fixed O&M Cost	$/yr	$7,503,827	$8,875,523
Variable Operating Costs			
Reagent Costs	$/yr	$1,606,745	$1,900,457
Sludge Disposal Cost for FGD System	$/yr	$946,636	$1,119,681
Credit for Byproduct	$/yr	$0	$0
SO2 Credits	$/yr	($8,199,329)	($9,698,164)
Steam Costs	$/yr	$0	$0
Water Cost - Fresh	$/yr	$5,872	$6,946
Water Cost - Blowdown	$/yr	$0	$0
FF Bags	$/yr	$614,926	$727,334
Additional Power Costs	$/yr	$2,724,171	$3,222,148
TOTAL First Year Variable Cost	$/yr	($2,300,979)	($2,721,597)

Circulating Fluid Bed with Fabric Filter

	First Year	Levelized

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000876

Fixed O&M Costs			
Operating Labor Cost	$/yr	$1,767,407	$2,090,489
Maintenance Labor and Materials Cost	$/yr	$3,794,595	$4,488,245
Administrative and Support Labor	$/yr	$826,246	$977,283
TOTAL First Year Fixed O&M Cost	$/yr	$6,388,248	$7,556,017
Variable Operating Costs			
Reagent Costs	$/yr	$2,191,016	$2,591,533
Sludge Disposal Cost for FGD System	$/yr	$1,183,029	$1,399,286
Credit for Byproduct	$/yr	$0	$0
SO2 Credits	$/yr	($8,199,329)	($9,698,164)
Steam Costs	$/yr	$0	$0
Water Cost - Fresh	$/yr	$569	$674
Water Cost - Blowdown	$/yr	$0	$0
FF Bags	$/yr	$614,926	$727,334
Additional Power Costs	$/yr	$2,600,523	$3,075,897
TOTAL First Year Variable Cost	$/yr	($1,609,267)	($1,903,440)

Mobotec Advanced OFA

		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$58,132	$68,758
TOTAL First Year Fixed O&M Cost	$/yr	$58,132	$68,758
Variable Operating Costs			
ROFA Fan Power	$/yr	$1,788,260	$2,115,153
TOTAL First Year Variable Cost	$/yr	$1,788,260	$2,115,153

Selective Catalytic Reduction

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$175,699	$207,817
Maintenance Labor and Materials Cost	$/yr	$863,354	$1,021,175
TOTAL First Year Fixed O&M Cost	$/yr	$1,039,054	$1,228,992
Variable Operating Costs			
Reagent	$/yr	$726,518	$859,326
Catalyst Replacement	$/yr	$5,345,435	$6,322,578
Catalyst Disposal	$/yr	$4,133	$4,889
Electricity	$/yr	$619,597	$732,859
High-dust SCR Steam	$/yr	$85,844	$101,536
NOx Credit	$/yr	$0	$0
Total First Year Variable O&M Costs	$/yr	$6,781,527	$8,021,187

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000877

Selective Noncatalytic Reduction			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$129,919	$153,668
TOTAL First Year Fixed O&M Cost	$/yr	$129,919	$153,668
Variable Operating Costs			
Reagent Cost	$/yr	$1,068,900	$1,264,295
Water Cost	$/yr	$0	$0
Additional Power Costs	$/yr	$12,247	$14,485
NOx Credit	$/yr	$0	$0
Total First Year Variable O&M Costs	$/yr	$1,081,147	$1,278,780

Low NOx Burners with Overfire Air			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$444,996	$526,341
TOTAL First Year Fixed O&M Cost	$/yr	$444,996	$526,341
Variable Operating Costs			
TOTAL First Year Variable Cost	$/yr	$0	$0

TOXECON I			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$1,403,092	$1,659,577
TOTAL First Year Fixed O&M Cost	$/yr	$1,403,092	$1,659,577
Variable Operating Costs			
Annual Sorbent Cost	$/yr	$4,976,569	$5,886,283
Sorbent Disposal Cost	$/yr	$10,971	$12,977
Additional Power Cost	$/yr	$1,093,449	$1,293,331
FF Bags	$/yr	$223,778	$264,685
Total First Year Variable O&M Costs	$/yr	$6,304,767	$7,457,276

TOXECON I.5			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$1,414,065	$1,672,556
TOTAL First Year Fixed O&M Cost	$/yr	$1,414,065	$1,672,556

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ETR_00000878

Variable Operating Costs			
Annual Sorbent Cost	$/yr	$16,588,562	$19,620,945
Sorbent Disposal Cost	$/yr	$36,572	$43,257
Additional Power Cost	$/yr	$1,132,930	$1,340,029
FF Bags	$/yr	$159,399	$188,537
Total First Year Variable O&M Costs	$/yr	$17,917,462	$21,192,767

TOXECON II

		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$776,471	$918,410
TOTAL First Year Fixed O&M Cost	$/yr	$776,471	$918,410
Variable Operating Costs			
Annual Sorbent Cost	$/yr	$16,588,562	$19,620,945
Sorbent Disposal Cost	$/yr	$36,572	$43,257
Additional Power Cost	$/yr	$56,401	$66,711
Total First Year Variable O&M Costs	$/yr	$16,681,535	$19,730,913

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000879

White Bluff 1 Levelized and First-Year O&M Cost Breakdown

Wet Limestone with Forced Oxidation:

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$2,813,048	$3,327,272
Maintenance Labor and Materials Cost	$/yr	$3,118,427	$3,688,474
Administrative and Support Labor	$/yr	$1,218,125	$1,440,798
TOTAL First Year Fixed O&M Cost	$/yr	$7,149,600	$8,456,544
Variable Operating Costs			
Reagent Costs	$/yr	$486,318	$575,217
Sludge Disposal Cost for FGD System	$/yr	$1,041,394	$1,231,760
Credit for Byproduct	$/yr	$0	$0
Dibasic Acid Costs	$/yr	$0	$0
SO2 Credit	$/yr	($9,873,805)	($11,678,732)
Steam Costs	$/yr	$0	$0
Water Cost - Blowdown Only	$/yr	$0	$0
Additional Power Costs	$/yr	$2,382,687	$2,818,241
TOTAL First Year Variable Cost	$/yr	($5,963,406)	($7,053,514)

Lime Spray Dryer with Fabric Filter

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$1,751,079	$2,071,175
Maintenance Labor and Materials Cost	$/yr	$4,665,334	$5,518,156
Administrative and Support Labor	$/yr	$932,223	$1,102,633
TOTAL First Year Fixed O&M Cost	$/yr	$7,348,636	$8,691,964
Variable Operating Costs			
Reagent Costs	$/yr	$1,530,902	$1,810,750
Sludge Disposal Cost for FGD System	$/yr	$889,996	$1,052,687
Credit for Byproduct	$/yr	$0	$0
SO2 Credits	$/yr	($9,516,088)	($11,255,625)
Steam Costs	$/yr	$0	$0
Water Cost - Fresh	$/yr	$5,595	$6,618
Water Cost - Blowdown	$/yr	$0	$0
FF Bags	$/yr	$584,148	$690,930
Additional Power Costs	$/yr	$2,611,986	$3,089,456
TOTAL First Year Variable Cost	$/yr	($3,893,461)	($4,605,185)

Circulating Fluid Bed with Fabric Filter

	First Year	Levelized

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000880

Fixed O&M Costs			
Operating Labor Cost	$/yr	$1,751,079	$2,071,175
Maintenance Labor and Materials Cost	$/yr	$3,679,423	$4,352,020
Administrative and Support Labor	$/yr	$813,914	$962,697
TOTAL First Year Fixed O&M Cost	$/yr	$6,244,415	$7,385,892
Variable Operating Costs			
Reagent Costs	$/yr	$2,087,593	$2,469,204
Sludge Disposal Cost for FGD System	$/yr	$1,118,848	$1,323,373
Credit for Byproduct	$/yr	$0	$0
SO2 Credits	$/yr	($9,516,088)	($11,255,625)
Steam Costs	$/yr	$0	$0
Water Cost - Fresh	$/yr	$543	$642
Water Cost - Blowdown	$/yr	$0	$0
FF Bags	$/yr	$584,148	$690,930
Additional Power Costs	$/yr	$2,481,563	$2,935,192
TOTAL First Year Variable Cost	$/yr	($3,243,394)	($3,836,285)

Mobotec Advanced OFA

		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$56,930	$67,336
TOTAL First Year Fixed O&M Cost	$/yr	$56,930	$67,336
Variable Operating Costs			
ROFA Fan Power	$/yr	$1,730,917	$2,047,327
TOTAL First Year Variable Cost	$/yr	$1,730,917	$2,047,327

Selective Catalytic Reduction

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$171,355	$202,679
Maintenance Labor and Materials Cost	$/yr	$859,022	$1,016,051
TOTAL First Year Fixed O&M Cost	$/yr	$1,030,377	$1,218,730
Variable Operating Costs			
Reagent	$/yr	$1,107,787	$1,310,290
Catalyst Replacement	$/yr	$5,134,519	$6,073,107
Catalyst Disposal	$/yr	$3,970	$4,696
Electricity	$/yr	$621,341	$734,922
High-dust SCR Steam	$/yr	$130,921	$154,853
NOx Credit	$/yr	$0	$0
Total First Year Variable O&M Costs	$/yr	$6,998,538	$8,277,868

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000881

Selective Noncatalytic Reduction			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$130,498	$154,353
TOTAL First Year Fixed O&M Cost	$/yr	$130,498	$154,353
Variable Operating Costs			
Reagent Cost	$/yr	$1,312,933	$1,552,936
Water Cost	$/yr	$0	$0
Additional Power Costs	$/yr	$15,043	$17,792
NOx Credit	$/yr	$0	$0
Total First Year Variable O&M Costs	$/yr	$1,327,975	$1,570,729

Low NOx Burners with Overfire Air			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$435,685	$515,328
TOTAL First Year Fixed O&M Cost	$/yr	$435,685	$515,328
Variable Operating Costs			
TOTAL First Year Variable Cost	$/yr	$0	$0

TOXECON I			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$1,365,181	$1,614,736
TOTAL First Year Fixed O&M Cost	$/yr	$1,365,181	$1,614,736
Variable Operating Costs			
Annual Sorbent Cost	$/yr	$4,727,485	$5,591,667
Sorbent Disposal Cost	$/yr	$10,422	$12,328
Additional Power Cost	$/yr	$1,039,348	$1,229,340
FF Bags	$/yr	$340,753	$403,042
Total First Year Variable O&M Costs	$/yr	$6,118,008	$7,236,377

TOXECON I.5			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$1,379,138	$1,631,244
TOTAL First Year Fixed O&M Cost	$/yr	$1,379,138	$1,631,244

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000882

Variable Operating Costs			
Annual Sorbent Cost	$/yr	$15,758,282	$18,638,890
Sorbent Disposal Cost	$/yr	$34,741	$41,092
Additional Power Cost	$/yr	$1,076,853	$1,273,701
FF Bags	$/yr	$113,584	$134,347
Total First Year Variable O&M Costs	$/yr	$16,983,460	$20,088,030

TOXECON II

		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$757,951	$896,504
TOTAL First Year Fixed O&M Cost	$/yr	$757,951	$896,504
Variable Operating Costs			
Annual Sorbent Cost	$/yr	$15,758,282	$18,638,890
Sorbent Disposal Cost	$/yr	$34,741	$41,092
Additional Power Cost	$/yr	$53,578	$63,372
Total First Year Variable O&M Costs	$/yr	$15,846,601	$18,743,354

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ETR_00000883

White Bluff 2 Levelized and First-Year O&M Cost Breakdown

Wet Limestone with Forced Oxidation:

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$2,882,646	$3,409,592
Maintenance Labor and Materials Cost	$/yr	$3,138,203	$3,711,865
Administrative and Support Labor	$/yr	$1,241,378	$1,468,302
TOTAL First Year Fixed O&M Cost	$/yr	$7,262,227	$8,589,759
Variable Operating Costs			
Reagent Costs	$/yr	$495,107	$585,613
Sludge Disposal Cost for FGD System	$/yr	$1,060,215	$1,254,022
Credit for Byproduct	$/yr	$0	$0
Dibasic Acid Costs	$/yr	$0	$0
SO2 Credit	$/yr	($11,343,030)	($13,416,531)
Steam Costs	$/yr	$0	$0
Water Cost - Blowdown Only	$/yr	$0	$0
Additional Power Costs	$/yr	$2,421,189	$2,863,781
TOTAL First Year Variable Cost	$/yr	($7,366,519)	($8,713,116)

Lime Spray Dryer with Fabric Filter

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$1,768,571	$2,091,865
Maintenance Labor and Materials Cost	$/yr	$4,703,760	$5,563,606
Administrative and Support Labor	$/yr	$940,035	$1,111,872
TOTAL First Year Fixed O&M Cost	$/yr	$7,412,366	$8,767,343
Variable Operating Costs			
Reagent Costs	$/yr	$1,558,569	$1,843,475
Sludge Disposal Cost for FGD System	$/yr	$906,081	$1,071,712
Credit for Byproduct	$/yr	$0	$0
SO2 Credits	$/yr	($10,978,848)	($12,985,777)
Steam Costs	$/yr	$0	$0
Water Cost - Fresh	$/yr	$5,696	$6,738
Water Cost - Blowdown	$/yr	$0	$0
FF Bags	$/yr	$592,494	$700,802
Additional Power Costs	$/yr	$2,642,231	$3,125,230
TOTAL First Year Variable Cost	$/yr	($5,273,777)	($6,237,821)

Circulating Fluid Bed with Fabric Filter

	First Year	Levelized

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ETR_00000884

Fixed O&M Costs			
Operating Labor Cost	$/yr	$1,768,571	$2,091,865
Maintenance Labor and Materials Cost	$/yr	$3,713,671	$4,392,528
Administrative and Support Labor	$/yr	$821,224	$971,343
TOTAL First Year Fixed O&M Cost	$/yr	$6,303,466	$7,455,737
Variable Operating Costs			
Reagent Costs	$/yr	$2,125,321	$2,513,829
Sludge Disposal Cost for FGD System	$/yr	$1,139,068	$1,347,290
Credit for Byproduct	$/yr	$0	$0
SO2 Credits	$/yr	($10,978,848)	($12,985,777)
Steam Costs	$/yr	$0	$0
Water Cost - Fresh	$/yr	$552	$653
Water Cost - Blowdown	$/yr	$0	$0
FF Bags	$/yr	$592,494	$700,802
Additional Power Costs	$/yr	$2,516,383	$2,976,377
TOTAL First Year Variable Cost	$/yr	($4,605,029)	($5,446,826)

Mobotec Advanced OFA

		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$58,220	$68,863
TOTAL First Year Fixed O&M Cost	$/yr	$58,220	$68,863
Variable Operating Costs			
ROFA Fan Power	$/yr	$1,792,508	$2,120,177
TOTAL First Year Variable Cost	$/yr	$1,792,508	$2,120,177

Selective Catalytic Reduction

		First Year	Levelized
Fixed O&M Costs			
Operating Labor Cost	$/yr	$176,021	$208,198
Maintenance Labor and Materials Cost	$/yr	$854,318	$1,010,487
TOTAL First Year Fixed O&M Cost	$/yr	$1,030,339	$1,218,685
Variable Operating Costs			
Reagent	$/yr	$1,127,808	$1,333,971
Catalyst Replacement	$/yr	$5,227,314	$6,182,865
Catalyst Disposal	$/yr	$4,042	$4,781
Electricity	$/yr	$632,571	$748,204
High-dust SCR Steam	$/yr	$133,288	$157,653
NOx Credit	$/yr	$0	$0
Total First Year Variable O&M Costs	$/yr	$7,125,022	$8,427,473

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Selective Noncatalytic Reduction			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$131,563	$155,613
TOTAL First Year Fixed O&M Cost	$/yr	$131,563	$155,613
Variable Operating Costs			
Reagent Cost	$/yr	$1,336,661	$1,581,002
Water Cost	$/yr	$0	$0
Additional Power Costs	$/yr	$15,314	$18,114
NOx Credit	$/yr	$0	$0
Total First Year Variable O&M Costs	$/yr	$1,351,975	$1,599,116

Low NOx Burners with Overfire Air			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$445,682	$527,152
TOTAL First Year Fixed O&M Cost	$/yr	$445,682	$527,152
Variable Operating Costs			
TOTAL First Year Variable Cost	$/yr	$0	$0

TOXECON I			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$1,378,093	$1,630,008
TOTAL First Year Fixed O&M Cost	$/yr	$1,378,093	$1,630,008
Variable Operating Costs			
Annual Sorbent Cost	$/yr	$4,795,031	$5,671,561
Sorbent Disposal Cost	$/yr	$10,571	$12,504
Additional Power Cost	$/yr	$1,054,022	$1,246,697
FF Bags	$/yr	$345,622	$408,801
Total First Year Variable O&M Costs	$/yr	$6,205,246	$7,339,562

TOXECON I.5			
		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$1,401,788	$1,658,035
TOTAL First Year Fixed O&M Cost	$/yr	$1,401,788	$1,658,035

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Variable Operating Costs			
Annual Sorbent Cost	$/yr	$15,983,438	$18,905,204
Sorbent Disposal Cost	$/yr	$35,237	$41,679
Additional Power Cost	$/yr	$1,092,062	$1,291,691
FF Bags	$/yr	$115,207	$136,267
Total First Year Variable O&M Costs	$/yr	$17,225,945	$20,374,841

TOXECON II

		First Year	Levelized
Fixed O&M Costs			
Maintenance Labor and Materials Cost	$/yr	$762,980	$902,453
TOTAL First Year Fixed O&M Cost .	$/yr	$762,980	$902,453
Variable Operating Costs			
Annual Sorbent Cost	$/yr	$15,983,438	$18,905,204
Sorbent Disposal Cost	$/yr	$35,237	$41,679
Additional Power Cost	$/yr	$54,344	$64,278
Total First Year Variable O&M Costs	$/yr	$16,073,019	$19,011,160

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REDACTED

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ETR_00000888

REDACTED

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD
ETR_00000889

REDACTED

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ETR_00000890

REDACTED

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ETR_00000891

[i] 10 Year Levelized All-In Power Price based on MIDAS June 2004 run 12C-18 for Northern Arkansas Region. Throughout the 10 years there is no capacity price in this region. Also assumes that Auxiliary and Replacement Power would both have to be purchased on the market.

[ii] 10 Year Levelized Weighted Average of Delivered Contract and Spot Coal taken from the July 30, 2004 Coal Forecast. We are currently in the process of revising this forecast and our current estimate for Independence is $1.37/MMBtu. However, this forecast is not finalized so we have included the price from our last published forecast.

[iii] 10 Year Levelized Price based on August 3, 2004 Corporate Henry Hub Gas POV. These prices include no transportation costs or taxes.

[iv] 10 Year Levelized Price of Distillate Fuel Oil #2 Gulf Coast Delivery based on August 13, 2004 Corporate Oil POV. Transportation cost as per conversation with Harrell Wise are $.212/MMBtu for Independence, REDACTED and $.11/MMBtu for White Bluff. Taxes on commodity only are applied to Independence and White Bluff at Arkansas rate of 6% and to REDACTED t Louisiana rate of 3.8%.

[v] All escalations are based on the GDP Deflator taken from the August 17, 2004 Corporate Inflation POV.

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ETR_00000892

ELECTRIC POWER RESEARCH INSTITUTE

NOx Reduction Assessment

ENTERGY's White Bluff and Independence Stations

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EPRI Senior Project Managers
December 10, 2008

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ETR_00000893

Objectives

- Assess Feasibility and Most Cost Effective Approach to Achieve NOx Emission Rates of 0.15 lb/MBtu or lower
  - White Bluff Steam Electric Station
  - Independence Steam Electric Station
- CAIR Required Only NOx Seasonal Compliance for Arkansas Stations
  - Ozone Season Currently May 1 to September 30
  - CAIR Rejected by Courts
- Review Current Equipment Condition and Operation in Context of Current NOx Emission Performance

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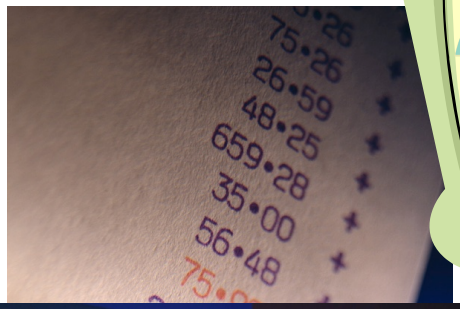
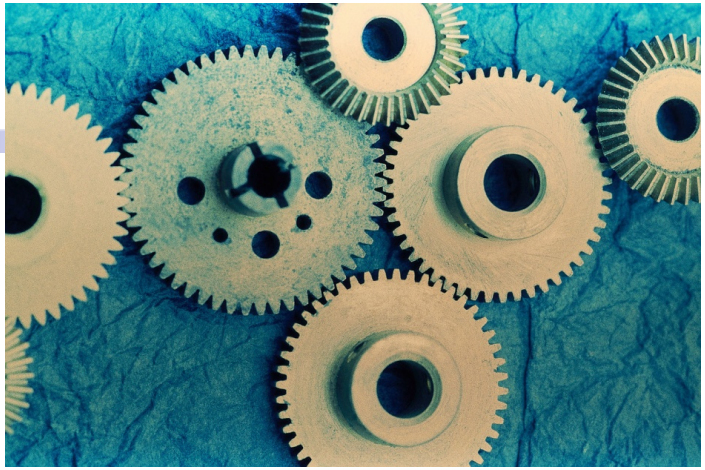
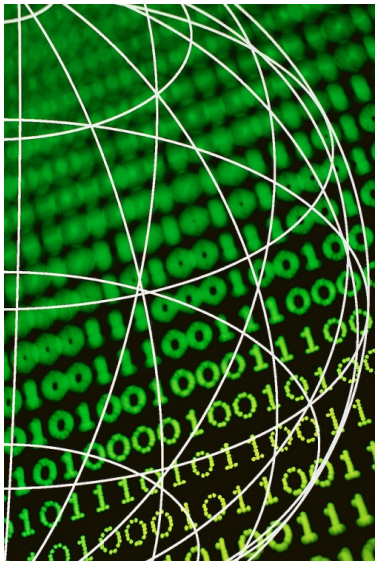
Background Information







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Industry Perspective

- T-fired Units Burning PRB Have Attained .15 lb NOx/Mbtu Via Combustion Staging

- Examples:
  - Rush Island
  - Baldwin
  - Labadie
  - Joppa

- Some have attained .10 lb NOx/Mbtu

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2007 Ozone Season NOx Emissions (lb/Mbtu)

	Average NOx	Full Load NOx	Minimum NOx	Load at Min NOx
White Bluff 1	.247	.247	.228	586
White Bluff 2	.287	.302	.263	679
Ind 1	.263	.270	.221	687
Ind 2	.248	.257	.224	762

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NOx Data Over Load Range

- NOx Emissions
  - Average = .26 lb/Mbtu
  - At full load = .27 lb/Mbtu

- NOx Increases to 0.25 – 0.30 lb/Mbtu at Higher and Lower Loads
  - Increasing NOx at higher loads typically attributable to thermal NOx formation due to higher heat release rates
  - Increasing NOx at lower loads typically attributable to fuel NOx due to increased combustion air to maintain steam temperatures

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Average NOx Reduction Cost per Unit for Each Ozone Season (Baseline NOx of 0.25 lb/MBtu)

NOx Credit Price NOx level (lb/MBtu)	$100	$300	$500	$700
0.20	$61,900	$185,700	$309,500	$433,300
0.15	$123,900	**$371,700**	$619,500	$867,300
0.10	$186,000	$558,000	$930,000	$1,302,000

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ETR_00000899

Unit Operation and Testing - 2008

- Excellent Hospitality and Cooperation from Each Site
- Up-to-date Information
  - In Addition to Results of Previous Tests
- Coal and Air Flow Information Collected
- Detailed ICT Reports Will Be Forwarded to Entergy
- Successfully (Temporarily) Staged Combustion

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ETR_00000900

Results of Recent Testing

- Air and Fuel Flow Imbalances Exist
- Fineness Out of Spec (Pulverizer Grind Performance)
- High Air to Fuel Ratio (AFRAT)
- Effects of Dropping Tilts

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Example Dirty Air Balance – IND 1 (should be within +/- 5%)

	Elevation	Elevation
Corner	A	B
1	-0.76	11.36
2	-0.94	-13.89
3	2.33	-0.86
4	2.01	-0.40
5	1.33	2.00
6	-4.13	6.07
7	-2.07	4.67
8	2.23	-8.96
Minimum	-4.13	-13.89
Maximum	2.33	11.36
abs avg	1.98	6.03
std dev	2.4	8.2

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ETR_00000902

Example Fuel Balance – WB 1 (should be within +/- 10%)

	Elevation	Elevation
Corner	A	B
1	-14.50	-26.29
2	-0.60	18.01
3	-21.98	-14.94
4	33.83	0.16
5	-32.68	-3.14
6	-4.02	-5.61
7	-8.67	40.98
8	48.62	-9.18
Minimum	-32.68	-26.29
Maximum	48.62	40.98
abs avg	20.61	14.79
std dev	27.7	20.9

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Average Unit Fineness Data

	IND 1	IND 2	WB 1	WB 2	GOAL
% on 50 mesh	2.11	2.03	2.68	2.41	0.3
% passing thru 200 mesh	63.24	62.84	64.39	65.31	75

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ETR_00000904

Individual AFRAT Data (should be 1.8-2.0)

AFRAT	A	B	C	D	E	F	G	H
IND 1	2.08	2.52	2.10	2.11	1.58	1.90	2.03	1.83
IND 2	na	2.37	1.78	1.63	1.74	1.86	2.01	2.11
WB 1	2.95	2.10	2.12	2.40	2.30	2.26	2.48	2.43
WB 2	2.51	2.91	2.11	2.00	2.48	2.50	2.50	2.58

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Tilt Effect Tests Results

- WB 2
  - Dropped Tilts from 30 to 15
  - Superheat Temperature Lost 9 F
  - NOx Dropped .04 lb/Mbtu
  - NOx Steady at 0.20 lb/Mbtu

- IND 2
  - Dropped Tilts from 12 to 0
  - Superheat Temperature Lost 6 F
  - NOx Dropped .04 lb/Mbtu
  - NOx Steady at 0.19 lb/Mbtu

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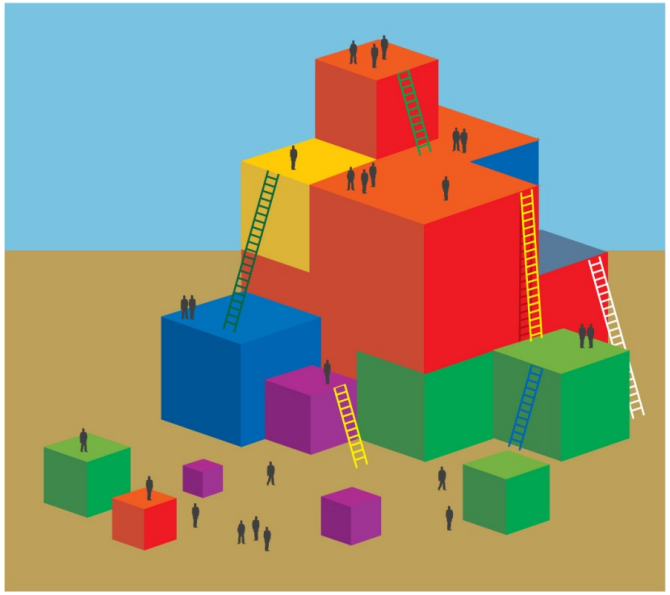
The Pre-requisites



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ETR_00000907

Recommendations (Pre-requisites)

- Ensure Proper Mill Performance
- Establish Fuel and Air Flow Balance
  - For Each Elevation / Burner Level
  - Via Riffler and Orifices
- Ensure All Burner Tilts are Fully Functional
- Ensure All Burner Tilts in Each Corner are in Synch
- Attain Consistent AFRAT of 1.8 - 2.0 for All Corners

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Improving Mill Performance

- Grind Fineness Specifications
  - >75% passing through 200 mesh screen
  - >99.7% passing through 50 mesh screen
- Mill Inspection to Identify Issues, or
- Mill Overhaul
  - Restore Clearances
  - Restore Surfaces
  - Check Grinding Force
  - 8 Mills / unit, >$100k / Mill
- Improves Flow Balance, Reduces Slagging Potential
- Small Reduction in NOx & Improvement in Heat Rate

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Air and Fuel Balance

- Inspect Rifflers
  - Replace / Restore Those Found Worn or Damaged
- Replace Orifices As Needed to Balance Each Level
- Estimated Costs
  - Inspect all 24 rifflers, $1k each
  - Replace ~6 rifflers, $5k each
  - Replace ~4 orifices per unit, $1k each
- Reduces Slagging Potential
- Small Reduction in NOx & Improvement in Heat Rate

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Tilts

- Restore Burner Tilts to Fully Functional
- Synchronize Tilts
- Estimated Costs:
  - WB 2, $50k
  - All other units, $10k

- Enable OFA Tilts
- Estimated Costs:
  - $20k per unit, including restoring feedback to DCS

- Permits Combustion Staging with Minimal Adverse Effects

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Primary Air to Fuel Ratio (AFRAT)

- Attain Consistent AFRAT of 1.8 - 2.0 for All Corners
- Primary Air to Coal Ratio Impacts Fuel Nitrogen Conversion to NOx, Even Under Staged Conditions
- Average AFRAT at Independence is Good, but 2 Lines on Each Unit Were Off-design
- All but one AFRAT on WB units were High
- Reducing Primary Air Flow Provides for More OFA
- May Require Control Settings Adjustments
- Cost $10k / Unit
- Will Result in Substantial NOx Reduction on WB Units

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Primary Recommendations

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ETR_00000913

Primary Recommendations

- Add Superheater Surface Area

- Stage Combustion
  - Bring all Burner Tilts to Horizontal or Below
  - Operate with Top BOOS at High Loads
  - Enable and Use OFA Tilts
  - Realize NOx Reduction
  - Realize Reduced FEGT and Slagging Potential

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Combustion Staging

- For Optimal Effect Add Superheater Surface Area
  - $4-8 million Modification
  - Reduces Slagging and Related Derates
  - Positive Return on Investment
- Bring all Burner Tilts to horizontal
  - Minimal Effect on Steam Temperatures
- Operate with Top Burner Out Of Service (BOOS)
  - At High Loads

- NOx Emission =.15 lb/Mbtu Should Be Attainable

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Additional Options

- Increase OFA Flow
- Reset Controls to Accept Lower Superheat Temperature
- Further Reduce Burner Tilts
- Update / Verify Unit Ratings Via Testing and Analysis

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Details on Additional Options

- Increase OFA Flow
  - Additional NOx Reduction
  - Improve Steam Temperatures
  - Available only if FD Fans Have Margin

- Reset Controls to Accept Lower Superheat Temperature and Further Reduce Burner Tilts
  - A 10 Degrees Drop Will Reduce Steam Temp by 10F
  - Worth about .04 lb/Mbtu Reduction in NOx
  - But Causes about .15% Heat Rate Penalty

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Details on Additional Options

- Update / Verify Unit Ratings Via Testing and Analysis
- Once Mill Performance, Air & Fuel Balance are Restored Additional Generating Capability Might Be Available
- WB2 Rating Currently > WB1?
  - Currently Requires Highest Burner Tilts
  - Struggles with Steam Temperatures

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Additional (& More Costly) Options

- SNCR (Selective Non-Catalyst Reduction)
  - $5 Million Capital Costs
  - .07 lb/Mbtu NOx drop
  - > $1 million Annual Operating Costs

- LNCFS III (Upgraded Over Fire Air and Burner System)
  - $11 Million Capital Costs
  - .10 Lb/Mbtu NOx Drop

- Do Nothing / Buy Allowances for Entire Difference
  - At $300 / ton NOx = $370,000 / Ozone Season

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ETR_00000919

Summary

- Install Additional Superheater Surface
  - Reduce FEGT and Frequency of Deslagging Derates
  - Enable Lowering of Tilts to Horizontal
  - Target Reduction of baseline NOx Approaching 0.15 lb/MBtu
- Re-establish Balanced Air and Coal Flows
- Synchronize Tilts, Ensure All are Fully Functional
- Set All AFRATs to 1.8 - 2.0
- Ensure Optimal Grind Leaving Pulverizers

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Post Script of Recommendations

- Additional NOx Reductions Most Economic Via Allowance Purchases:
  - Average Forecast Price of $300 / ton
  - LNCFS III Cost Effectiveness of ~$1,000 / ton
  - SNCR Cost Effectiveness of > $2,300 / ton
  - These Levelized Costs are Well Above Forecasted Seasonal NOx Allowance Prices

- NOx Reduction Values Assume Continuing PRB Coal
  - Switching to Higher Sulfur Coal Potentially Increases NOx Emissions and Increases Water Wall Wastage Risk

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ETR_00000922

Summary of Major Environmental Regulations Applicable to EAI Operations

HIGHLY SENSITIVE PROTECTED INFORMATION

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Rule	Summary of Rule and Impact	EAI Compliance Strategy
CATR- NOx	• Arkansas subject to Seasonal NOx cap in eastern U.S. Cap beginning in 2012 • Seasonal NOx applies to emissions between May and September of each year. • Sources must match emissions with allowance at the end of each season. • Affected sources buy/sell/trade under this cap with their allocated emission allowances.	• Evaluate cost of controls on a $/ton removed basis. • Evaluate seasonal NOx Allowance Market • Install controls below the market cost of emission credits. • To the extent that emissions are above EAI allocation, buy allowances on month ahead basis to fulfill operational needs.
CAMR	• Annual mercury cap for U.S. Cap starts in 2010 and tightens in 2018 • Sources must match emissions with credits at the end of the year. • Affected sources buy/sell/trade under this cap with their allocated emission credits. • Sources required to install mercury emissions monitoring equipment. • Courts vacated the mercury rule on February 8, 2008. EPA retracted petition for Supreme Court review during February 2009. No current rule in effect, but EPA promulgating Hazardous Air Pollutants(HAPs) Maximum Achievable Control Technology (MACT) standards. Future Rule not likely to be "Cap and Trade". • EPA issued Information Collection Request under Section 114 of the Clean Air Act to collect information to be used in development of new MACT rule. • EGU MACT expected to take the place of CAMR as early as 2015.	• Install mercury continuous emissions monitoring system. • Impact of ICR on Arkansas facilities is minimal. EAI must submit information only and is not required to perform stack testing for the ICR. • EGU MACT may require installation of scrubbers.
CAVR	• States required to develop plans to reduce emissions impacting Class I Protected areas. • For electric generating units, EPA rule defines Best Available Retrofit Technology (BART) for NOx and SO2 on units determined to have impact on regional haze at federal Class I areas. • Arkansas modified state regulation 19 on 9/28/07 requiring BART controls at White Bluff and Lake Catherine Unit 4. • EPA challenged Arkansas State Implementation Plan (SIP) in November 2009 delaying the 2013 mandatory compliance date for CAVR.	• White Bluff required to install Scrubbers and Low NOx Burners within 6 years of state SIP or 5 years of EPA approval, whichever is earlier. Lake Catherine required to install combustion NOx controls to meet lower limits. • A variance to Arkansas regulation was granted by Arkansas Pollution Control and Ecology Commission. White Bluff and Lake Catherine Pollution Control Equipment is not required until 5 years after EPA approves ADEQ SIP.

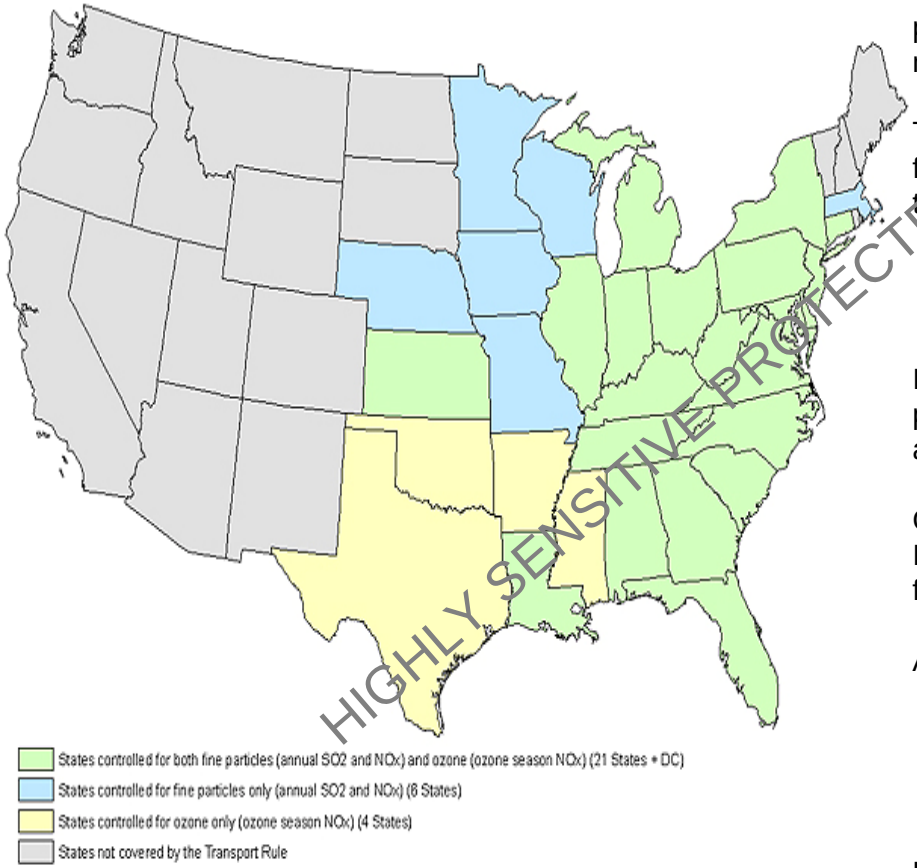
HIGHLY SENSITIVE PROTECTED INFORMATION

Rule	Summary of Rule and Impact	EAI Compliance Strategy
CCR	• EPA to begin regulating coal combustion residuals (CCRs, mainly flyash and bottom ash) as either "special wastes" or non-hazardous wastes. • Subtitle C hazardous waste regulation would regulate CCRs disposed in landfills or surface impoundments. The Subtitle C option would regulate CCRs from the point of generation to final disposal and would include regulation of siting, liners, run-on and run-off controls, ground water monitoring, fugitive dust controls, financial assurance, corrective action and closure. Specific beneficial uses of CCRs, primarily those deemed "encapsulated," will be exempted from regulation and continued recycling would be promoted. • Subtitle D non-hazardous waste regulation would not require federal permits but new landfills or lateral expansions constructed after issuance of the final rule would be subject to minimum liner requirements, groundwater monitoring, leachate collection, and closure/post-closure care.	• Continue to work with industry group USWAG to monitor rulemaking developments, potential outcome and legislative strategy. • Latest projection on EPA's final rulemaking determination looks to be toward end of 2012. • Evaluate cost impact of upgrades under various ash determination scenarios and recycling rates. • Anticipate increased landfilling need due to potential reduction in ash sales. Ash sales are expected to drop considerably should ash destined for disposal be designated as hazardous due to market stigma.

HIGHLY SENSITIVE PROTECTED INFORMATION

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD

States covered by the Transport Rule:



Clean Air Transport Rule

The Transport Rule will limit pollution from power plants that are located in 31 eastern, southern, and midwestern states and DC.

This proposal reduces emissions contributing to fine particle (PM2.5) and ozone nonattainment that travel across state lines:

- Sulfur dioxide (SO2)and nitrogen oxides (NOx) contribute to PM 2.5 transport
- NOx contributes to ozone transport

In August 2010 the Clean Air Transport Rule was proposed to replace the Clean Air Interstate Rule in an attempt to affect interstate emissions transport.

Currently, EAI is complying with the Clean Air Interstate Rule until the Clean Air Transport Rule is finalized.

Arkansas is unique among states…

1) Does not participate in annual NOx and SO2 cap program for downwind particulates
2) Is required to meet seasonal NOx cap for downwind ozone.

EAI is developing a compliance strategy pending final Clean Air Transport Rule.

HIGHLY SENSITIVE PROTECTED INFORMATION

Confidential Business Information

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ETR_00000926

Clean Air Visibility Rule

The Clean Air Visibility Rule require eligible units that contribute to the visibility degradation of a Class I area (national park or national scenic area) to install controls by 2013 to reduce emissions of NOx, SO2, and particulate matter.

Eligible units are those that were under construction from 1962 through 1977.

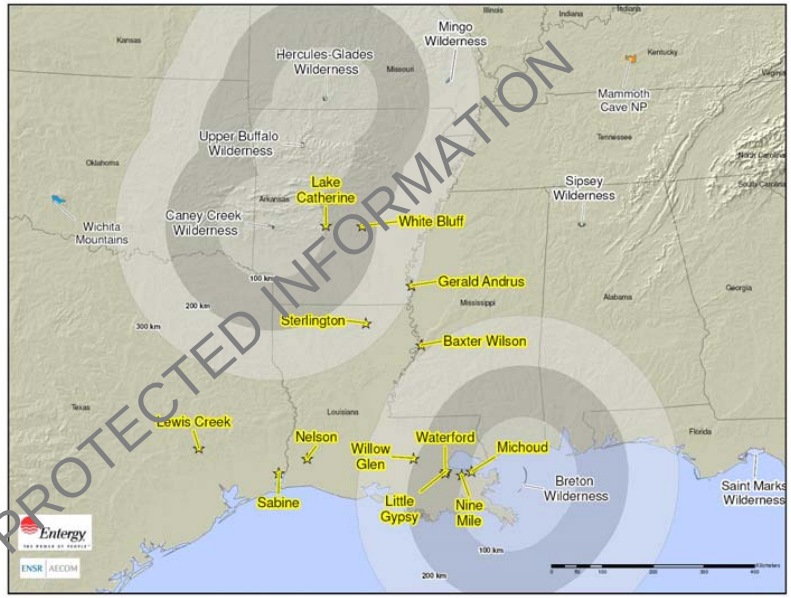
Four Class 1 areas within 150km of EAI BART eligible facilities: Caney Creek, Upper Buffalo, Hercules Glade, and Mingo Wilderness

Best Available Retrofit Technology (BART) is described in the Regional Haze Rule for Affected Units

Arkansas Dept. of Environmental Quality developed State Implementation Plan to reduce SO2 and NOx at affected facilities.

Adopted into State Regulation 19 on September 28, 2007.

EPA challenged the PSD Permit for the White Bluff scrubbers in November 2009 which could delay the 2013 mandatory compliance date for CAVR.



September 28, 2007 Arkansas Regulation 19 mandated that White Bluff:
- Limit SO2 emission rate to 0.15 Lb/MMBtu*
- Limit NOx emission rate to 0.15 Lb/MMBtu*
- Commercial operations within 6 years of State Regulation or 5 years of EPA approval which ever is earlier**

September 28, 2007 State Regulation 19 mandated that Lake Catherine Unit 4:
- When burning gas: Limit NOx emission rate to 0.15 Lb/MMBtu.
- When burning oil: Limit SO2 emission rate to 0.562 Lb/MMBtu

*White Bluff emission limits have been challenged by EPA
**APCE granted variance from state deadline. New deadline is as expeditiously as practical but no later than 5 years after EPA approves ADEQ SIP.

HIGHLY SENSITIVE PROTECTED INFORMATION

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Complying with these requirements will require significant plant investments

CATR Projects:

- EAI is expected to purchase seasonal NOx allowances to cover its compliance gap.

CAMR Projects

- The impact of the February 2008 Federal Court Action to vacate this regulation is discussed later but EAI will defer all control projects.
  - Deferred CAMR projects include installation and maintenance of activated carbon injection systems at Independence and White Bluff.
  - EGU MACT expected to take the place of the CAMR may require scrubbers as early as 2015

CAVR Projects

- The impact of the November 2009 EPA challenge of the PSD permit to install scrubbers is discussed later but EAI has deferred the White Bluff scrubber and Separated Overfire Air control projects.
  - Under the current ADEQ SIP White Bluff will have to install scrubbers and low NOx burners with Separated Overfire Air to meet presumptive limits under EPA's Regional Haze rule.
- Lake Catherine 4 is also required by this rule to install NOx controls. EAI is evaluating the future role of this unit in light of this investment.
- Additional scrubber details are provided in a separate section.

Allowances

- Costs will vary depending on assumptions of
  - Capacity Factors
  - Emission Rate
  - Allowance Market Price Changes

HIGHLY SENSITIVE PROTECTED INFORMATION

Confidential Business Information

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ETR_00000928

Compliance Plan Development

HIGHLY SENSITIVE PROTECTED INFORMATION

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Summary of CATR NOx Cap and Trade Compliance Strategy

HIGHLY SENSITIVE PROTECTED INFORMATION

- To date no controls have been determined to generate reductions below the projected allowance market price for the respective pollutants.

- EAI purchased seasonal NOx allowances in 2009 & 2010 to cover shortages under the CAIR Program and expects to be short seasonal NOx allowances in the future under the CATR Program and will have to purchase from the emissions market to meet operational obligations.

- There are a variety of sensitivities and risks that influence this compliance plan which have been evaluated and considered in its development.
  - Future generation levels
  - Technology performance
  - Allowance availability risk
  - Allowance cost

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD

NOx Control Selection Model

- A variety of potential NOx controls can be installed individually or in combinations
- Model analyzes up to 191 different control technology groups for each unit and ranks by incremental $/ton removal
- Model develops both average and incremental $/ton removal costs for each technology group
- Key Input Variables
  - Real -levelized cost of control groups
    - Capital cost
    - O&M cost
    - Fuel Impact
  - Projected NOx emissions without controls
    - Unit capacity factors
    - Unit heat rates
    - NOx emission rates
  - Removal efficiencies of control groups which determine average tons of NOx removed
- The incremental $/ton removal can then be compared to projected NOx allowance prices when evaluating potential NOx control investments.
- All modeling evaluations to date determined it is more economical to purchase allowances when compared to the cost of installing controls.

HIGHLY SENSITIVE PROTECTED INFORMATION

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Mercury Compliance Strategy

CAMR Projects

- Until February 2008 the CAMR compliance plan included projects at Independence and White Bluff to install Toxecon 2.
- The EGU MACT is expected to replace the CAMR and require coal units to meet specific limits as opposed to a cap and trade regulation. The EGU MACT will likely require scrubbers on White Bluff and Independence.

Impact of February 2008 Court Decision

- EAI will defer all mercury control projects until the EGU MACT is proposed.

HIGHLY SENSITIVE PROTECTED INFORMATION

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White Bluff Scrubber and Low NOx Projects

HIGHLY SENSITIVE PROTECTED INFORMATION

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD

CAVR Compliance Strategy

HIGHLY SENSITIVE PROTECTED INFORMATION

CAVR Projects

- Until November 2009 the CAVR compliance plan included the installation of a scrubber and Separated Overfire Air on both White Bluff units by October 15, 2013.

Impact of November 2009 EPA Challenge

- On March 26, 2010, APC&E Commission granted a variance from Arkansas compliance requirements, therefore EAI has deferred all Scrubber and Separated Overfire Air projects until the Arkansas SIP is approved by EPA.
- Arkansas SIP approval projected during last quarter of 2011.

Confidential Business Information
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Pending White Bluff Scrubber and Low NOx Burners Conceptual Design Basis

HIGHLY SENSITIVE PROTECTED INFORMATION

- The draft Arkansas SIP, which is pending EPA approval, would lower the NOx emission rate to 0.15 Lb/MMBtu and the SO2 emission rate to 0.15 Lb/MMBtu in order to curtail the plant's impact on Federal Class 1 areas. This would require:
  - Installation of Dry Flue Gas Desulphurization technology (scrubber) to reduce SO2 by 95%
  - Retrofitting boilers with low NOx burners and separated overfire air (LNB/SOFA) in order to reduce NOx by approximately 50%.
- Dry Flue Gas Desulphurization (Dry Scrubber)
  - Major new equipment consists of:
    - Lime pile and material handling equipment.
    - Scrubber Reactor Vessel
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    - By Product Handling/Landfill upgrades
- PRB Coal with blending of other coals based on SPO analysis
- Regulatory In Service Deadline – Pending

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Scrubber installation at White Bluff will require significant capital investments.

Entergy Corporation's 3rd Q 2007 10-Q disclosed a $350 million estimate for EAI's share of the project cost.

The latest conceptual cost estimate has gone up significantly from previous estimates due to increases in equipment, commodity, and labor costs. Entergy Corporation's 3rd Q 2008 10-Q disclosed a $630 million estimate for EAI's share of the project cost

Entergy's Fourth Quarter 2009 earnings report list EAI's share of the estimated project cost as $465 million.

HIGHLY SENSITIVE PROTECTED INFORMATION

Confidential Business Information

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CCR Compliance Strategy

- Continue to work with industry group USWAG to monitor rulemaking developments, potential outcome and legislative strategy.
- Latest projection on EPA's final rulemaking determination looks to be toward end of 2012.
- Evaluate cost impact of upgrades under various ash determination scenarios and recycling rates.
- Anticipate increased landfilling need due to potential reduction in ash sales. Ash sales are expected to drop considerably should ash destined for disposal be designated as hazardous due to market stigma.

HIGHLY SENSITIVE PROTECTED INFORMATION

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Summary of Major Environmental Regulations Applicable to EAI Operations

HIGHLY SENSITIVE PROTECTED INFORMATION

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Rule	Summary of Rule and Impact	EAI Compliance Strategy
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Confidential Business Information
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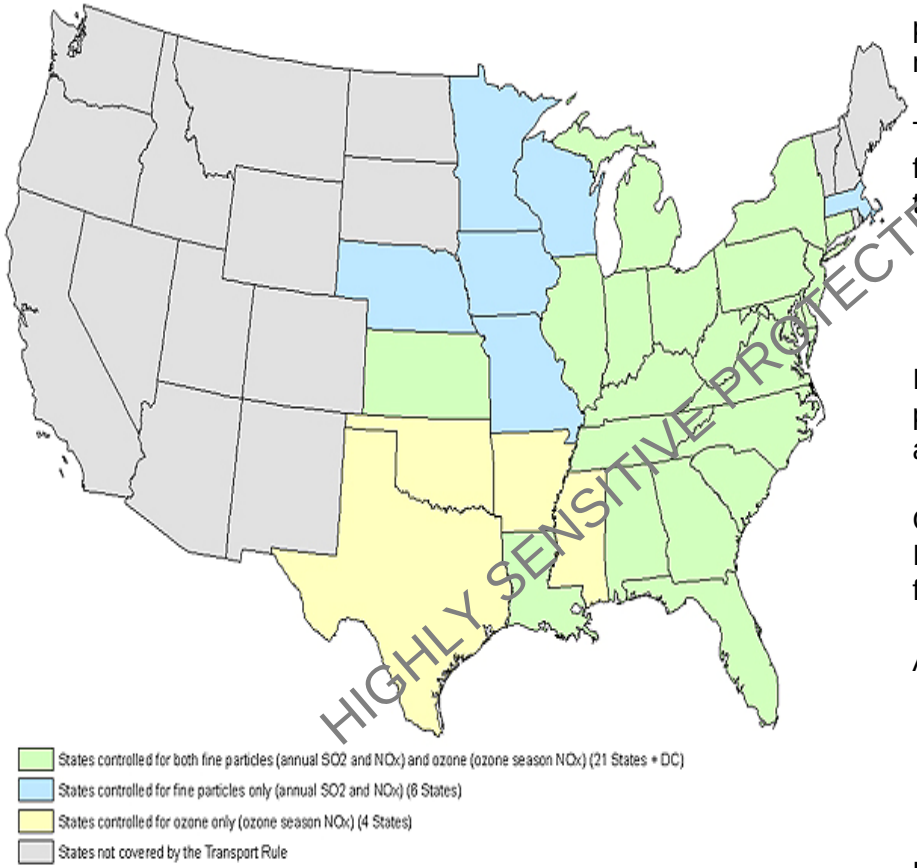
States covered by the Transport Rule:



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Arkansas is unique among states…

1) Does not participate in annual NOx and SO2 cap program for downwind particulates
2) Is required to meet seasonal NOx cap for downwind ozone.

EAI is developing a compliance strategy pending final Clean Air Transport Rule.

HIGHLY SENSITIVE PROTECTED INFORMATION

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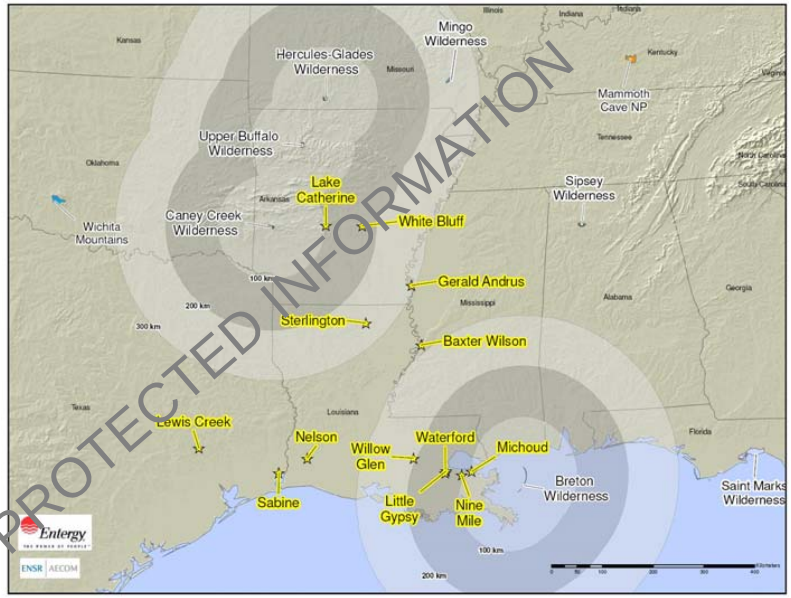

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Complying with these requirements will require significant plant investments

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CAMR Projects

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- Additional scrubber details are provided in a separate section.

Allowances

- Costs will vary depending on assumptions of
  - Capacity Factors
  - Emission Rate
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ETR_00000943

Compliance Plan Development

HIGHLY SENSITIVE PROTECTED INFORMATION

Confidential Business Information
Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Summary of CATR NOx Cap and Trade Compliance Strategy

HIGHLY SENSITIVE PROTECTED INFORMATION

- To date no controls have been determined to generate reductions below the projected allowance market price for the respective pollutants.

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NOx Control Selection Model

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    - NOx emission rates
  - Removal efficiencies of control groups which determine average tons of NOx removed
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Mercury Compliance Strategy

CAMR Projects

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Impact of February 2008 Court Decision

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White Bluff Scrubber and Low NOx Projects

HIGHLY SENSITIVE PROTECTED INFORMATION

Confidential Business Information

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CAVR Compliance Strategy

HIGHLY SENSITIVE PROTECTED INFORMATION

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Pending White Bluff Scrubber and Low NOx Burners Conceptual Design Basis

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ENTERGY

Generation &
Transmission Group
White Bluff Plant
P. O. Box 126
Redfield, AR 72132
Tel 501 688 7390

Document: WB-PE-750

Date: December 14, 1992

To: Steve Coker

From: Jerry Reed JR

Subject: **System Plant Controls Upgrade QAT**
White Bluff Controls Upgrade

A list of controls upgrades for the plant has been compiled and is enclosed. Also the "Plant Controls Database" form has been filled out with as much information as possible. Please advise if additional information is required.

cc Max Halbert
Rick Perryman
Dale Swindle
John Lee
Robert Rickett

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

WBSES CONTROL UPGRADES

CONTROL UPGRADES TO DATE

SYSTEM	MANUFACTURER	$ INVESTED	YEAR
Fly Ash Cycle Timers Units 1 & 2	GE Fenuc	$ 15,000	
Plant Bus Mimic Panel	Optomux	$ 105,000	85
Plant Events Recorder	Rochester	$ 132,000	87
Soot Blower Control System Unit 1	Optomux	$ 60,000	88
Soot Blower Control System Unit 2	Optomux	$ 60,000	88
Fire Monitoring System	Optomux	$ 30,000	88
Dewatering Bin Controls	Optomux	$ 80,000	90,91
Boiler Information System Unit 1 & 2	Optomux	$ 100,000	90,91
Plant Computer AMU Replacement Phases 1, 2, & 3	Foxboro	$ 436,000	90,91, 92
Boiler Feed pump Turbine Controls Unit 1	LoveJoy	$ 350,000	91
Boiler Feed pump Turbine Controls Unit 2	Love Joy	$ 350,000	92
RCD Train Positioner	Allen-Bradley	$ 233,000	92
Rotary Car Dumper	Allen-Bradley	$ 106,000	92
TOTAL $ INVESTED		$2,057,000	

BUDGETED UPGRADES FOR 1993

Plant Annunicator	Rochester	$ 150,000	93
Plant AMU Replacement Phase 4	Foxboro	$ 150,000	93
TOTAL 1993 $ INVESTMENT		$ 300,000	

PROPOSED UPGRADES FOR 1994

Water Treatment Plant Controls	Allen-Bradley	$ 100,000	94
Plant AMU Replacement Phase 5	Foxboro	$ 249,000	94
Stacker/Reclaimer Controls	Allen-Bradley	$ 336,000	94
TOTAL 1994 $ INVESTMENT		$ 685,000	

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

PROPOSED UPGRADES BETWEEN 1995 - 1999

SYSTEM	MANUFACTURER	$ INVESTED	YEAR
Plant DMU Replacement	Foxboro	$ 150,000	95
Boiler Controls Upgrade (CCS) Unit 1	Foxboro	$1,800,000	95
Misc. Analog Controls System Unit 1	Foxboro	$ 300,000	95
Ring Balance Meter Replacement Unit 1	Foxboro	$ 291,000	95
Bottom Ash Control Systems Unit 1	Allen-Bradley	$ 200,000	96
Plant CPU Replacement	Foxboro	$ 150,000	96
Boiler Control Upgrade (CCS) Unit 2	Foxboro	$1,800,000	96
Misc. Analog Controls System Unit 2	Foxboro	$ 300,000	96
Ring Balance Meter Replacement Unit 2	Foxboro	$ 291,000	96
Bottom Ash Control Systems Unit 2	Allen-Bradley	$ 200,000	97
Aux Boiler Controls		$ 50,000	98
GE TSI Replacement Unit 1	GE	$ 150,000	98
RSI Installation Unit 1	GE	$ 150,000	98
Burner Management System (FSSS) Unit 1	Foxboro Allen-Bradley	$ 300,000	98
GE TSI Replacement Unit 2	GE	$ 150,000	99
RSI Installation Unit 2	GE	$ 150,000	99
Burner Management System (FSSS) Unit 2	Foxboro Allen-Bradley	$ 300,000	99
TOTAL INVESTMENT 1995-1999		$6,732,000	

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Confidential Business Information ETR_00001491

PROJECT DESCRIPTIONS

PLANNED FOR 1993

Plant Annunicator	Rochester	$ 150,000

This upgrade would replace the existing plant annunicator which is obsolete. The logic cards are static sensitive are easily damaged when changing indicators in the light boxes. Also, the replacement cards are becoming difficult to obtain. This upgrade would insure the annunicator reliability

Plant AMU Replacement Phase 4	Foxboro	$ 150,000

This improvement will be the next phase of replacing the outdated Foxboro 1A system.

PLANNED FOR 1994

Plant AMU Replacement Phase 5	Foxboro	$ 249,000

This will be a continuation of the phase out replacement of the Foxboro 1A computer system with the new generation of Foxboro IA.

Water Treatment Plant Controls	Allen-Bradley	$ 66,000

This project will replace the relay controls for the Water Treatment plant with a PLC system. A local operator screen will be provided for monitoring the system.

This project is required to maintain water quality for the boiler.

PROPOSED FUTURE UPGRADES

Aux. Boiler Controls	(Not Specified)	$ 200,000

This project will replace the Auxiliary Boiler analog controls with a small configurable control system. This would replace the discrete boiler feed water, boiler drum level, steam pressure, and fuel master controllers with a small DCS type system.

The improvements are necessary to improve the operation of the boiler.

Plant DMU Replacement	Foxboro	$ 150,000

This will be phase 6 of the phased project. The digital inputs will be changed over to the Foxboro IA type modules.

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Confidential Business Information ETR_00001492

Plant CPU Replacement	Foxboro	$ 150,000

This will be the last phase of upgrading the Foxboro 1A system to the IA system.

Boiler Controls Upgrade (CCS) Unit 1	Foxboro	$1,800,000
Boiler Controls Upgrade (CCS) Unit 2	Foxboro	$1,800,000

The existing analog Coordinated Control System (CCS) will be upgraded to a digital control system.

The analog type of controls provided with the boiler are failing and replacements are becoming difficult to obtain. The change to a digital control system will improve the operation and insure higher operating availability.

Misc. Analog Controls System Unit 1	Foxboro	$ 300,000
Misc. Analog Controls System Unit 2	Foxboro	$ 300,000

The Miscellaneous Analog Control panel will be upgraded to the Foxboro IA type of architecture. This system includes the DA level controls, Pegging steam

Ring Balance Meter Replacement Unit 1	Foxboro	$ 291,000
Ring Balance Meter Replacement Unit 2	Foxboro	$ 291,000

The existing low differential pressure ring balance transmitters are obsolete and the compensation circuits are a maintenance problem. This upgrade would replace the meters with a conventional type of transmitter and moving the compensation circuits to the DCS.

Bottom Ash Control Systems Unit 1	Allen-Bradley	$ 200,000
Bottom Ash Control Systems Unit 2	Allen-Bradley	$ 200,000

The discrete relay logic used in the control system for the bottom ash handling system would be upgraded to a PLC.

GE TSI Replacement Unit 1	(Not Specified)	$ 150,000
GE TSI Replacement Unit 2	(Not Specified)	$ 150,000

The existing controls for the Turbine Supervisory Instrumentation (TSI) are obsolete and unreliable. The system will be replaced with a new generation type of controls

RSI Installation Unit 1	(Not Specified)	$ 150,000
RSI Installation Unit 2	(Not Specified)	$ 150,000

A Rotor Stress Instrumentation System will be installed to monitor the stress inside the turbine.

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Confidential Business Information ETR_00001493

Burner Management System (FSSS) Unit 1	Foxboro Allen-Bradley	$ 300,000
Burner Management System (FSSS) Unit 2	Foxboro Allen-Bradley	$ 300,000

The existing hardware logic is becoming more maintenance intensive and will be upgraded to a software configurable type of system.

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Confidential Business Information ETR_00001494

Plant Controls Database
Updated Last: _____

Basic Site Information

Plant Name: White Bluff SES Unit Number: 1 MW Capacity: 815 Commission Date: 8/22/80
Plant Manager: Max Halbert Plant Contact: Jerry Reed
Phone No.: 501/688-7390 FAX No.: 501/688-7196
Address: P.O. Box 126 city Redfield state AR zip: 72132-0126

Existing Unit Heat Rate: 10,760 BTU/Net KWH Performance Calculations Done: (Y/N) _____
Condition of Drawings and Associated Information: (1-10) 8.5 (10 = best)
Size of I & C Staff: 8 Shift 9 days Number of Operators in Control Room: 2 BTG 1 Coal
Percentage of Fuel Natural Gas: 0 Number of Sources: —
Percentage of Fuel #2 Fuel Oil: 0.3% Percentage of Fuel #6 Fuel Oil: 0
Percentage of Fuel Coal: 99.3% Other Source: — Percentage: 0

Information From S.O.C.

Service Hours: 82,973 #Start-ups: _____ Type of Load Control: (Auto/Manual) _____
Availability for Last Five Years: 88.94% Projected Dispatch for Next Five Years: _____
Capacity Factors for Last Five Years: 58.5% Type of Dispatch: (Base/Peak/Cycle): Cycle
Projected Capacity Factors for Next Five Years: _____ Forced Outage Rate per Yr.: 2.14%
Minimum Load: 160 Maximum Load: 815 Ramp Rate: 12 mw/min
Number of Reserve Outages per yr.: 4.75 Unit Service Status: (In/Out/ERS): In
NERC Codes: 1) _____, 2) _____, 3) _____, 4) _____ (1 is most frequent occurrence)
Load Control Reliable? (1-10 best) _____

Unit Information

Boiler Manufacturer: CE Model: _____ Type: Controlled Circulation
Generator Manufacturer: GE Model: _____ Type: Water-H_2 Cooled
Turbine Manufacturer: GE Model: G3 Type: TC4F-33.5

				(y/n)	
Exist. Boiler Control	Vendor: TVI	Year New: 1980	Reliable: Y		Yr. Last Mod.: 1989
Exist. Flame Safety	Vendor: CE	Year New: 1980	Reliable: Y		Yr. Last Mod.: 1980
Exist. Burner Mgt.	Vendor:	Year New:	Reliable:		Yr. Last Mod.:
Exist. Data Acquisition	Vendor: Foxboro	Year New: 1980	Reliable: Y		Yr. Last Mod.: 1992

Present Type of Boiler Control: (analog, pneumatic, digital) analog
Present Balance of Plant Logic Controls: (analog, digital, comb., relay) analog digital relay

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Plant Controls Database
Updated Last: _____

Basic Site Information

Plant Name: White Bluff SES Unit Number: 2 Mw Capacity: 844 Commission Date: 7/23/81
Plant Manager: Max Halbert Plant Contact: Jerry Reed
Phone No.: 501/1688-7390 FAX No.: ___/___-____
Address: PO Box 126 city Redfield state AR zip: 72132-0126

Existing Unit Heat Rate: 10,283 BTU/Net KWH Performance Calculations Done: (Y/N) _____
Condition of Drawings and Associated Information: (1-10) 8.5 (10 = best)
Size of I & C Staff: 8 shift 9 days Number of Operators in Control Room: 2 BTG
Percentage of Fuel Natural Gas: 0 Number of Sources: —
Percentage of Fuel #2 Fuel Oil: 0.3% Percentage of Fuel #6 Fuel Oil: 0
Percentage of Fuel Coal: 99.7% Other Source: — Percentage: 0

Information From S.O.C.

Service Hours: 79,860 #Start-ups: _____ Type of Load Control: (Auto/Manual) _____
Availability for Last Five Years: 86.08% Projected Dispatch for Next Five Years: _____
Capacity Factors for Last Five Years: 56.0% Type of Dispatch: (Base/Peak/Cycle): Cycle
Projected Capacity Factors for Next Five Years: _____ Forced Outage Rate per Yr.: 2.59%
Minimum Load: 160 Maximum Load: 844 Ramp Rate: 12 MW/min
Number of Reserve Outages per yr.: 3.8 Unit Service Status: (In/Out/ERS): In
NERC Codes: 1) _____, 2) _____, 3) _____, 4) _____ (1 is most frequent occurrence)
Load Control Reliable? (1-10 best) _____

Unit Information

Boiler Manufacturer: CE	Model: _____	Type: Controled Circulation		
Generator Manufacturer: GE	Model: _____	Type: Water-H_2 Cooled		
Turbine Manufacturer: GE	Model: G3	Type: TC4F-33.5		

			(y/n)	
Exist. Boiler Control	Vendor: W	Year New: 1980	Reliable: Y	Yr. Last Mod.: 1987
Exist. Flame Safety	Vendor: CE	Year New: 1980	Reliable: Y	Yr. Last Mod.: 1980
Exist. Burner Mgt.	Vendor: _____	Year New: _____	Reliable: ___	Yr. Last Mod.: ___
Exist. Data Acquisition	Vendor: Foxboro	Year New: 1980	Reliable: Y	Yr. Last Mod.: M2

Present Type of Boiler Control: (analog, pneumatic, digital) _____
Present Balance of Plant Logic Controls: (analog, digital, comb., relay) analog digital relay

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ISES CONTROL UPGRADES

DRAFT DRAFT DRAFT

TO DATE:

SYSTEM	MANUFACTURER	$ INVESTED
D/A Level & Pressure, Cond. PP Recirc.	Foxboro	200,000
Boiler Ring Balance Meter Replacement	Foxboro	292,000
Plant Computer AMU Replacement	Foxboro	300,000
RCD Train Positioner	Allen-Bradley	283,000
Stacker/Reclaimer Controls	Allen-Bradley	335,996
Fly Ash Cycle Timers	Allen-Bradley	15,000
Plant Event Recorder	Beta	80,000

PLANNED FOR 1993:

Boiler Ring Balance Meter Replacement Unit 2	Foxboro	291,000
Hotwell Level Controls & Actuators Both Units	Foxboro	92,000
Plant Computer AMU Replacement	Foxboro	150,000
Rotary Car Dumper	Allen-Bradley	150,000
Hydroveyor & Pyrites Controls	Allen-Bradley	50,000

PLANNED FOR 1994:

SYSTEM	$ ESTIMATED
Boiler Controls and Actuators & Burner Management Front End Replacement Unit 2	1,800,000

The present analog controls have several identified areas of deficiency. The present Aux Air System does not adequately maintain the windbox to furnace differential thus causing an estimated $200,000 per outage in burner front damage. Damage to the burner front also effects the availability of the nozzle tilts to help in steam temperature control. The present Steam Temperature Controls have been identified through testing to be the primary limiting factor in the coal units being able to participate effectively in system load control. Steam temperatures are presently exceeding design parameters and long term damage to critical boiler components is occurring. The Mill Air Flow Controls can not provide a safe automatic mill startup. Presently the operator must place the hot and cold air dampers in manual when starting the coal feeder in order to maintain adequate air flow. Adequate air flow is essential to prevent mill explosions.

This project will install modern digital controls to replace the existing analog controls. Advanced control schemes will be implemented to provide tighter control over boiler parameters. Ramp rate capability will be increased to provide more system control to the SOC. All final drives will be replaced with more reliable ones. The front end to the FSSS will be replaced so as to maintain good control room ergonomics. Control will be through workstations mounted in the existing BTG board.

Plant Computer AMU Replacement	150,000

This will be the third phase in a six phase project to upgrade the plant computer.

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ISES CONTROL UPGRADES

DRAFT DRAFT DRAFT

Aux. Boiler Controls The present analog controls are not reliable and need to be replaced. This project will provide modern digital controls which will connect to the plant DCS	200,000
Water Treatment Controls The present relay based controls are not reliable and need to be replaced. This project will provide modern digital controls which will connect to the plant DCS.	100,000
Plant Aunnunciator Replacement The present annuniciator has components that are no longer manufactured. When the current supply runs out, it will become unserviceable. This project will replace the annunciator with new equipment compatible with the new plant event recorder.	120,000

PLANNED FOR 1995:

Boiler Controls and Actuators & Burner Management Front End Replacement Unit 1 Reason and goals are the same as Unit 2	1,800,000
Plant Computer AMU Replacement This will be the fourth phase in a six phase project to upgrade the plant computer.	150,000
Sample Panel Data Acquisition The present recorders are obsolete and parts are no longer available. This project will replace the recorders with DCS hardware and workstation.	80,000

PLANNED FOR 1996:

Plant Computer AMU Replacement This will be the fifth phase in a six phase project to upgrade the plant computer.	150,000

PLANNED FOR 1997:

Plant Computer DMU Replacement This will be the final phase in a six phase project to upgrade the plant computer.	150,000

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ISES CONTROL UPGRADES

DRAFT DRAFT DRAFT

POSSIBLE SOMETIME BETWEEN 1994 THRU 1999:

SYSTEM	$ ESTIMATED
Burner Management Both Units The present hardwired logic is becoming more troublesome and harder to maintain. This project will replace the existing FSSS with digital controls.	600,000
Precipitator Energy Management Both Units When the plant computer replacement is completed, the existing precip. computer will also have to be replaced. This project will replace the Foxboro 300 computer with Foxboro I/A hardware.	600,000
GE ATSI Replacement Both Units The present hardware used for advanced turbine supervisory instrumentation (ATSI) is obsolete and very unreliable. This project will replace the ATSI with DCS hardware.	300,000
GE RSI Replacement Both Units The present hardware used for rotor stress instrumentation (RSI) is obsolete and very unreliable. This project will replace the RSI with DCS hardware.	300,000
Ash Handling Controls Both Units The present relay based controls are not reliable and need to be replaced. This project will replace the controls with modern digital controls compatible with the existing DCS.	300,000
Coal Handling Controls Both Units The present relay based controls are not reliable and need to be replaced. This project will replace the controls with modern digital controls compatible with the existing DCS.	400,000

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ENTERGY PLANT CONTROL UPGRADE QUALITY ACTION TEAM

PROCESS OWNER: Robert Tanis

TEAM LEADER: Lewis Hirschy (Plant Engineering Supervisor, Coal Ops., Independence Plant)

TEAM MEMBERS:

Mona Draper	Senior Facilitator, Total Quality Improvement, New Orleans
Lester Jenkins	Engineer, ETS, Design Engineering, Miss.
Nick Musmeci	Engineer, ETS, Design Engineering, New Orleans
Steve Coker	Engineer, Coal Ops., Independence Plant
I.B. Stewart	Operations Superintendent, Southern Region, Michoud Plant
John Booth	Plant Betterments, Northern Region, Lake Catherine Plant
Luis Maldonado	Supervisor, Maintenance Engineering & Standards, ETS, Design Engineering, New Orleans
Wayne Barcelo	Supervisor, Special Systems, Systems Development, System Operations, New Orleans

PRIMARY CUSTOMERS: Power Plant Directors, Mr. James Kenney

TEAM "DELIVERABLES":

1. Develop a System Document (and accompanying process flowchart) that addresses technical and O&M considerations for control upgrade decisions.

2. Develop a data base of existing controls and data acquisition systems currently in use on the System's units and the upgrades planned in the future.

3. Develop engineering guidelines necessary to assure technical adequacy and overall quality of future control upgrades.

4. Evaluate Entergy control vendor performance and make recommendations concerning vendor-related issues.

5. Develop an evaluation methodology (including, but not limited to cost-benefit considerations) tailored to control projects that would be used for future control upgrades.

6. Develop a suggested order to implement planned control upgrades for the System and each Region.

ESTIMATED COMPLETION: March 1, 1993

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ISES CONTROL UPGRADES

DRAFT DRAFT DRAFT

TO DATE:

Mill monitor System Optomux

SYSTEM	MANUFACTURER	$ INVESTED
D/A Level & Pressure, Cond. PP Recirc.	Foxboro	200,000
Boiler Ring Balance Meter Replacement	Foxboro	292,000
Plant Computer AMU Replacement	Foxboro	300,000
RCD Train Positioner	Allen-Bradley	283,000
94 Stacker/Reclaimer Controls	Allen-Bradley	335,996
Fly Ash Cycle Timers	Allen-Bradley	15,000
Plant Event Recorder	Beta	80,000
Deaerator Bin Controls	Optomux	
BFPT Controls	Loveyoy	
Plant Bus Mimic Panel	Optomux	
Fire monitor System	Optomux	
Sootblower Control System Both Units	Optomux	

125, 171, 140 } 436

PLANNED FOR 1993:

Boiler Ring Balance Meter Replacement Unit 2	Foxboro	291,000
Hotwell Level Controls & Actuators Both Units	Foxboro	92,000
Plant Computer AMU Replacement	Foxboro	150,000 OK
~~Rotary Car Dumper~~	~~Allen-Bradley~~	~~150,000~~
~~Hydroveyor & Pyrites Controls~~	~~Allen-Bradley~~	~~50,000~~
Annunciator	Rochester	

PLANNED FOR 1994:

SYSTEM	$ ESTIMATED
Boiler Controls and Actuators & Burner Management Front End Replacement Unit 2	1,800,000

The present analog controls have several identified areas of deficiency. The present Aux Air System does not adequately maintain the windbox to furnace differential thus causing an estimated $200,000 per outage in burner front damage. Damage to the burner front also effects the availability of the nozzle tilts to help in steam temperature control. The present Steam Temperature Controls have been identified through testing to be the primary limiting factor in the coal units being able to participate effectively in system load control. Steam temperatures are presently exceeding design parameters and long term damage to critical boiler components is occurring. The Mill Air Flow Controls can not provide a safe automatic mill startup. Presently the operator must place the hot and cold air dampers in manual when starting the coal feeder in order to maintain adequate air flow. Adequate air flow is essential to prevent mill explosions.

This project will install modern digital controls to replace the existing analog controls. Advanced control schemes will be implemented to provide tighter control over boiler parameters. Ramp rate capability will be increased to provide more system control to the SOC. All final drives will be replaced with more reliable ones. The front end to the FSSS will be replaced so as to maintain good control room ergonomics. Control will be through workstations mounted in the existing BTG board.

Plant Computer AMU Replacement — 150,000 249,000

This will be the third phase in a six phase project to upgrade the plant computer.

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ISES CONTROL UPGRADES

DRAFT DRAFT DRAFT

Aux. Boiler Controls 200,000

The present analog controls are not reliable and need to be replaced.

This project will provide modern digital controls which will connect to the plant DCS

Water Treatment Controls 100,000 93

The present relay based controls are not reliable and need to be replaced.

This project will provide modern digital controls which will connect to the plant DCS.

Plant Aunnunciator Replacement 120,000

The present annuniciator has components that are no longer manufactured. When the current supply runs out, it will become unserviceable.

This project will replace the annunciator with new equipment compatible with the new plant event recorder.

PLANNED FOR 1995:

Boiler Controls and Actuators & Burner Management Front End Replacement Unit 1 1,800,000

Reason and goals are the same as Unit 2

Plant Computer ~~AMU~~ DMU Replacement 150,000 ok

This will be the fourth phase in a six phase project to upgrade the plant computer.

Sample Panel Data Acquisition 80,000

The present recorders are obsolete and parts are no longer available.

This project will replace the recorders with DCS hardware and workstation.

PLANNED FOR 1996:

Plant Computer ~~AMU~~ CPU Replacement 150,000 ok

This will be the fifth phase in a six phase project to upgrade the plant computer.

PLANNED FOR 1997:

~~Plant Computer DMU Replacement~~ ~~150,000~~

~~This will be the final phase in a six phase project to upgrade the plant computer.~~

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ISES CONTROL UPGRADES

DRAFT DRAFT DRAFT

POSSIBLE SOMETIME BETWEEN 1994 THRU 1999:

SYSTEM	$ ESTIMATED
Burner Management Both Units The present hardwired logic is becoming more troublesome and harder to maintain. This project will replace the existing FSSS with digital controls.	600,000
Precipitator Energy Management Both Units When the plant computer replacement is completed, the existing precip. computer will also have to be replaced. This project will replace the Foxboro 300 computer with Foxboro I/A hardware.	600,000
GE ATSI Replacement Both Units The present hardware used for advanced turbine supervisory instrumentation (ATSI) is obsolete and very unreliable. This project will replace the ATSI with DCS hardware.	300,000
GE RSI Replacement Both Units The present hardware used for rotor stress instrumentation (RSI) is obsolete and very unreliable. This project will replace the RSI with DCS hardware.	300,000
Boiler Ash Handling Controls Both Units to include ~~Bottom~~ Pyrites & Hydroveyors The present relay based controls are not reliable and need to be replaced. This project will replace the controls with modern digital controls compatible with the existing DCS.	300,000
Coal Handling Controls Both Units The present relay based controls are not reliable and need to be replaced. This project will replace the controls with modern digital controls compatible with the existing DCS.	400,000

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Plant Controls Database
Updated Last:_____

Basic Site Information

Plant Name:_____ Unit Number:___ Mw Capacity:____ Commission Date: __/__/__
Plant Manager:_____ Plant Contact:_____
Phone No.:___/___-____ FAX No.:___/___-____
Address:_____ city_____ state_____zip:_____

Existing Unit Heat Rate:_____ Performance Calculations Done: (Y/N)_____
Condition of Drawings and Associated Information: (1-10)_____(10 = best)
Size of I & C Staff:_____ Number of Operators in Control Room:_____
Percentage of Fuel Natural Gas:_____ Number of Sources:_____
Percentage of Fuel #2 Fuel Oil:_____ Percentage of Fuel #6 Fuel Oil:_____
Percentage of Fuel Coal:_____ Other Source:_____ Percentage:_____

Information From S.O.C.

Service Hours:_____ #Start-ups:_____ Type of Load Control:(Auto/Manual)_____
Availability for Last Five Years:_____ Projected Dispatch for Next Five Years:_____
Capacity Factors for Last Five Years:_____ Type of Dispatch:(Base/Peak/Cycle):_____
Projected Capacity Factors for Next Five Years:_____ Forced Outage Rate per Yr.:_____
Minimum Load:_____ Maximum Load:_____ Ramp Rate:_____
Number of Reserve Outages per yr.:_____ Unit Service Status:(In/Out/ERS):_____
NERC Codes: 1)_____,2)_____,3)_____,4)_____ (1 is most frequent occurrence)
Load Control Reliable?(1-10 best)_____

Unit Information

Boiler Manufacturer:_____ Model:_____ Type:_____
Generator Manufacturer:_____ Model:_____ Type:_____
Turbine Manufacturer:_____ Model:_____ Type:_____

			(y/n)	
Exist. Boiler Control	Vendor:_____	Year New:_____	Reliable:___	Yr. Last Mod.:___
Exist. Flame Safety	Vendor:_____	Year New:_____	Reliable:___	Yr. Last Mod.:___
Exist. Burner Mgt.	Vendor:_____	Year New:_____	Reliable:___	Yr. Last Mod.:___
Exist. Data Acquisition	Vendor:_____	Year New:_____	Reliable:___	Yr. Last Mod.:___

Present Type of Boiler Control: (analog, pneumatic, digital)_____
Present Balance of Plant Logic Controls: (analog, digital,comb.,relay)_____

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Plant Controls Database
Updated Last:_____

Basic Site Information

Plant Name:_____ Unit Number:___ Mw Capacity:____ Commission Date: __/__/__
Plant Manager:_____ Plant Contact:_____
Phone No.:___/___-____ FAX No.:___/___-____
Address:_____ city_____ state_____zip:_____

Existing Unit Heat Rate:_____ Performance Calculations Done: (Y/N)_____
Condition of Drawings and Associated Information: (1-10)_____(10 = best)
Size of I & C Staff:_____ Number of Operators in Control Room:_____
Percentage of Fuel Natural Gas:_____ Number of Sources:_____
Percentage of Fuel #2 Fuel Oil:_____ Percentage of Fuel #6 Fuel Oil:_____
Percentage of Fuel Coal:_____ Other Source:_____ Percentage:_____

Information From S.O.C.

Service Hours:_____ #Start-ups:_____ Type of Load Control:(Auto/Manual)_____
Availability for Last Five Years:_____ Projected Dispatch for Next Five Years:_____
Capacity Factors for Last Five Years:_____ Type of Dispatch:(Base/Peak/Cycle):_____
Projected Capacity Factors for Next Five Years:_____ Forced Outage Rate per Yr.:_____
Minimum Load:_____ Maximum Load:_____ Ramp Rate:_____
Number of Reserve Outages per yr.:_____ Unit Service Status:(In/Out/ERS):_____
NERC Codes: 1)_____,2)_____,3)_____,4)_____ (1 is most frequent occurrence)
Load Control Reliable?(1-10 best)_____

Unit Information

Boiler Manufacturer:_____ Model:_____ Type:_____
Generator Manufacturer:_____ Model:_____ Type:_____
Turbine Manufacturer:_____ Model:_____ Type:_____

			(y/n)	
Exist. Boiler Control	Vendor:_____	Year New:_____	Reliable:___	Yr. Last Mod.:___
Exist. Flame Safety	Vendor:_____	Year New:_____	Reliable:___	Yr. Last Mod.:___
Exist. Burner Mgt.	Vendor:_____	Year New:_____	Reliable:___	Yr. Last Mod.:___
Exist. Data Acquisition	Vendor:_____	Year New:_____	Reliable:___	Yr. Last Mod.:___

Present Type of Boiler Control: (analog, pneumatic, digital)_____
Present Balance of Plant Logic Controls: (analog, digital,comb.,relay)_____

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

ENTERGY

Generation &
Transmission Group
Independence Plant
P. O. Box 416
Newark, AR 72562
Tel 501 799 8761

MEMO

Date: November 4, 1992

To: Robert Tanis

From: Lewis Hirschy Lewis Hirschy

Subject: **System Plant Control Upgrade QAT**
Meeting #2 - Minutes and Subsequent Activities
Meeting # 3 - Agenda

All members of the QAT met in New Orleans for the second set of meetings on Oct. 23 and 24, 1992. During these meetings we were able to develop a set of actions that will lead to the achievement of our deliverables. We were also able to develop a work schedule and assignments to support final report completion by 1 March 1993. Last, but not least, we started work on a very precise definition of what the terms "Control" and "Upgrade" mean in regard to this QAT. Since the processes developed by this QAT are intended to apply to plants across the system, any confusion about what is considered a "Control Upgrade" must be avoided.

After the meeting, work proceeded to finalize the definitions of "Control" and "Upgrade". Work was started on the design of the data base for existing control equipment and the format for collecting future control upgrade information. Luis Maldonado and I met with you and Randy Dufour to work through some thorny issues surrounding Deliverable 4. Finally, the Little Gypsy, Waterford and White Bluff Plants were visited and information was shared about QAT activities.

The last section of this memo presents an agenda for Meeting # 3 as well as a schedule for meetings through mid January.

I. MEETING # 2 MINUTES

KEY DEFINITIONS .... "CONTROL" AND "UPGRADE"

While reviewing work from the first set of meetings, the Team realized that a critical factor had been overlooked .... just exactly what is a "Control Upgrade"? Without a precise definition, "Control Upgrade" could be interpreted in many ways. This, of course, must be avoided if the work of this QAT is to have any lasting benefit.

It was decided that a separate definition should be developed for "Control" and "Upgrade".

In regard to "Control", we felt that a detailed listing of specific equipment should be provided since there are many different plant designs throughout the System. Work proceeded after the meeting to finalize the listing of "Control" hardware.

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Confidential Business Information ETR_00001506

The Team decided that control hardware included in any of the following systems is considered as "control" for this QAT:

FUEL MANAGEMENT
- Coal Hndl & Storage
- Fuel Oil Hndl & Storage
- Natural Gas Systems

DATA ACQUISITION
- Annunciator & Alarm
- Performance Monitoring
- Logs

PRE-BOILER SYSTEMS
- Condensate
- Condensers
- Feedwater Heaters
- Vacuum Systems
- Feed Pumps & Drives

ELEC. DIST. SYSTEMS
- Batteries
- Vital AC
- Emergency Power
- Aux Power
- Transformers
- Switchyard

BOILER CONTROLS
- Fans
- Fuel/Air
- Feedwater
- Steam Temp
- Soot Blowers
- Auxiliary Monitoring

BLR. SAFETY SYSTEMS
- Burner Safety Controls
- Flame Detection

T/G CONTROLS
- Main Turbine Control
- Turbine Supervisory
- Vibration
- Rotor Stress
- Generator Gas
- Stator Cooling
- Seal Air

ENVIRONMENTAL
- Air
- Water
- CEM's
- Ground Water

COOLING WTR. SYS'S
- Pumps
- Heat Exchangers
- Screens
- Ponds
- Cooling Towers
- Make Up & Blowdown

WASTE MANAGEMENT
- Ash Handling
- Precipitators

BALANCE OF PLANT
- Fire Protection
- Freeze Protection
- Aux Boiler
- Water Treatment Plant
- Water Conditioning
- Sewage Systems
- Gas Handling Systems
- Chemical Hndl Systems
- Air Systems

We decided that the term "Upgrade" should be defined rather simply as:

UPGRADE

A modification to a plant's controls that involves or results in any of the following:

1. *Different technology*
2. *Different capability*
3. *Different control logic*
4. *Total costs (material and labor) above $5,000*
5. *Modifications that are or will be related to other controls.*

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1. Determine a time frame for future control upgrades.
2. Determine if upgrades already budgeted for 1993 should be included in the list.

D. Accomplish plant visits and other activities necessary to identify desired future control upgrades.

3. DEVELOP ENGINEERING GUIDELINES NECESSARY TO ASSURE TECHNICAL ADEQUACY AND OVERALL QUALITY OF FUTURE CONTROL UPGRADES.

DELIVERABLE CLARIFICATION:

Earlier clarifications for this deliverable remain valid; however, as discussion continued, the Team decided to develop "guidelines" in the form of "philosophy" statements. In this way, a general framework can be developed to guide all concerned with control upgrades. We anticipate that references will be made to EPRI documents when more specific engineering topics need guidance.

DELIVERABLE ACTION PLAN:

A. Study EPRI documents and other sources.
B. Develop an Entergy control upgrade design philosophy.

The System's control upgrade design philosophy should form the foundation for every control upgrade. Input devices, final drives, software, I/O, expandability, compatibility, etc. are examples of things that this philosophy will embrace. This philosophy will be independent of vendors.

C. Develop an Entergy control upgrade "installation" philosophy.

The System's control upgrade "installation" philosophy should ensure that the physical installation of every control upgrade meets its user's needs. One of the most fundamental aspects of this philosophy will deal with how the engineers managing a project solicit ideas from O&M personnel. Other factors include the degree to which old systems remain intact, the physical location of hardware, the importance given to human factors engineering, etc. This philosophy should be independent of vendors.

4. DEVELOP CRITERIA FOR EVALUATION OF VENDOR ALLIANCE CONSIDERATIONS.

--- CHANGED TO ---

4. EVALUATE ENTERGY CONTROL VENDOR PERFORMANCE AND MAKE RECOMMENDATIONS CONCERNING VENDOR-RELATED ISSUES.

DELIVERABLE CLARIFICATION

Accurately developing the intent for this deliverable has been a challenge. In the summary of the first set of meetings, it was stated that the Team would concentrate on alliance considerations to include

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budgetary pricing. After further guidance from our customers and reflection on this deliverable, the scope of the Team's efforts is being more focused on ***technical*** considerations.

There are several questions regarding vendors that this QAT will address and answer from the ***technical*** perspective. Business or commercial considerations are a separate issue and may need to be dealt with by another QAT. When and if a future QAT deals with issues such as "alliances" or "leveraged buys", it will be essential that the System's technical control upgrade philosophy and processes are in place.

Following are the most nagging questions that management and engineer alike have been asking with regard to control vendors:

- ***Are the control vendors that the System does business with top performers now and will they be in the future?***

  Performance criteria can be developed to clearly indicate if a vendor is a "Top performer". A "Top performer" vendor will have state-of-the-art hardware and software on the market and will be poised to maintain a leadership role in the control industry.

  System engineers have gained a wealth of information in the last five years as they have managed dozens of control upgrades. EPRI has conducted a study that deals with vendor evaluations. The Instrument Society of America publishes a handbook devoted to vendor comparisons. Numerous power industry magazine articles deal with vendor performance. In sort, there is ample experience and material for this QAT to develop performance criteria against which our vendors can be evaluated.

- ***Which vendors should be used for future control upgrades?***

  When the data associated with Deliverable 2 is collected and vendor performance criteria are defined, it will be possible to develop a Kepner Tregoe decision methodology to determine which vendor should be used for each future control upgrade. No doubt, many factors will be considered. Examples may include:

  - Do vendors under consideration meet "Top Performer" criteria?
  - What vendor's equipment is already in use?
  - What vendor is used in the Region?
  - What type and how many additional control upgrades are planned for the Unit in the future?
  - Are O&M personnel trained on and pleased with a vendor's hardware and software?

- ***Does Entergy do business with too many control vendors?***

  Again, just considering technical matters, the answer to this question will depend on the current and projected performance of the vendors we currently do business with. It will also be influenced by the current and projected investment level with each vendor. Another consideration will be maximization of System engineering resources. For these reasons, answers to the first two questions are a prerequisite for answering this question.

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From a technical perspective, is there any advantage to pursuing a vendor alliance or other agreement with any of our control vendors?

After we know what controls exist in the System, what upgrades are desired for the future (Deliverable 2) and the answer to the three questions just asked, then the Team will have the knowledge to answer this question.

DELIVERABLE ACTION PLAN:

A. Study EPRI documents and other sources.
B. Develop vendor performance criteria and evaluate existing vendors.
C. Develop and apply a Kepner Tregoe methodology for selection of a vendor for each new control upgrade.
D. Determine if vendor alliances would be advantageous.

5. DEVELOP AN EVALUATION METHODOLOGY (INCLUDING, BUT NOT LIMITED TO COST BENEFIT CONSIDERATIONS) TAILORED TO CONTROL PROJECTS THAT WOULD BE USED FOR FUTURE CONTROL UPGRADES.

DELIVERABLE CLARIFICATION:

No change from the last meeting; however, it should be emphasized that this KT methodology is different than the KT methodology discussed on the previous page.

DELIVERABLE ACTION PLAN:

A. Study EPRI documents and other sources.
B. Develop a Kepner Tregoe methodology that will allow control upgrades to be compared to each other.

6. DEVELOP A SUGGESTED ORDER TO IMPLEMENT PLANNED CONTROL UPGRADES FOR THE SYSTEM AND EACH REGION.

DELIVERABLE CLARIFICATION:

The Team discussed the benefit of including only *major* control upgrades in the System list (value large enough to be a capital budget item) and *all* control upgrades in each Region's list. The reason for this idea was the recognition of how projects are currently prioritized and authorized. The Team decided to postpone further consideration of this topic until more is known about the desired control upgrades. After some data is collected, this item will be addressed.

DELIVERABLE ACTION PLAN:

A. Apply the KT methodology to each control upgrade identified in Deliverable 2.
B. Analyze the data and rank order all control upgrades.
C. Determine if small upgrades need to be included in the System listing.

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II. ACTIVITIES SUBSEQUENT TO THE SECOND MEETING

Kerry Tabor provided assistance in developing the schedule of activities and work assignments for the QAT. This schedule will be published as an attachment to these memos after meeting #3..

The summary sheet of QAT members and deliverables as shown in Attachment 2 was faxed to the Plant Managers of Gerald Andrus, Delta, Couch and Lake Catherine Plants.

Work started on scheduled activities as follows (the Deliverable number and activity letter is shown below to aid in cross referencing to the schedule):

1A.	The definitions for "control" and "upgrade" were developed.
2A and 2B.	Data base formats were developed.
3A, 4A and 5A.	EPRI reports are being procured. Several Team members already have copies and have started study. A package of eight recent magazine articles from power industry magazines is being distributed to Team members. Finally, the ISA Distributed Control Systems Manual is on order.

The definitions , formats and topics just mentioned will be reviewed, modified as necessary and approved by the entire Team during meeting #3.

On Oct. 30, 1992, Luis Maldonado and I met with you and Randy Dufour to discuss Deliverable 4 (Criteria for Evaluation of Vendors). As a result of this meeting, the Team will be able to focus more effectively in the area of vendor evaluations.

I visited with the White Bluff Plant staff on Oct. 29 and answered questions about QAT activities. I also gave them a copy of the QAT summary sheet.

Nick Musmeci and I visited the Little Gypsy and Waterford plants on Oct. 30, 1992. The QAT summary sheet will also be provided to these plants.

III. MEETING # 3 AGENDA & FUTURE MEETINGS

MEETING #3

DATE: November 5-6, 1992
LOCATION: Jackson Ms., Capital Towers, 10th floor Conference Room
TIME: 9:00 AM

AGENDA:

1. Discuss Deliverables 1 and 4 to ensure that everyone is comfortable with recent changes.
2. Finalize data base formats and data time frame considerations.
3. Finalize definitions of "control" and "upgrade"
4. Ensure that everyone has copies of EPRI documents and magazine articles.

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5. Compare notes on research done so far.
6. Revise the schedule.
7. Start work with ETS Technology Development on collecting data.
8. Begin working in smaller groups as directed by the schedule.

FUTURE MEETINGS

Upcoming meeting days have been scheduled. In order to minimize travel time, we decided to have back-to-back meetings on Thursday and Friday every other week, rotated among locations as follows:

November 19-20	Little Rock
December 3-4	New Orleans
December 17-18	Little Rock
January 7-8	Jackson

cc:

Frank Gallaher (TLC 3301)	Mickey Cox (TLC 3310)
Jim Rider (TLC 3311)	Glenn Phillips (TLC 3312)
Randy Dufour (TLC 3213)	Mona Draper (TLC 2310)
John Booth (Lake Catherine Plant)	Steve Coker (ISES)
Lester Jenkins (MPL Box 057)	Luis Maldonado (TLC 3213)
Nick Musmeci (TLC 3211)	I. B. Stewart (N107)

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ENTERGY

Generation &
Transmission Group
Independence Plant
P. O. Box 416
Newark, AR 72562
Tel 501 799 8761

Date: October 21, 1992

To: Robert Tanis

From: Lewis Hirschy

Subject: **System Plant Control Upgrade QAT**
Meeting # 1 - Minutes and Subsequent Activities
Meeting # 2 - Agenda

This memo, as well as similar subsequent memos, will document our activities both for you and our primary customer group .... the power plant Directors.

All members of the QAT met in New Orleans for the first meeting on Oct. 8, 1992. We were able to order our activities according to the previously published agenda and made good progress toward finalizing team organization. The first section of this memo documents our activities.

After the Oct. 8 meeting, the Couch and Lake Catherine Plants were visited on Oct. 16 and on Oct. 20, the Gerald Andrus and Delta plants were visited. The second section of this memo documents these visits.

The last section presents an agenda for Meeting # 2 as well as a schedule for meetings through mid November.

I. MEETING # 1 MINUTES

PROCESS OWNER GUIDANCE

As the Director assigned as Process Owner, you opened the meeting by giving general guidance and background information. After a short overview of the effort necessary to reach agreement on the QAT Charter, the Team's relationship to control vendors was explained. Basically, we need to be careful to keep the focus of the Team on "technical" strategy as opposed to "business" strategy. Our involvement with vendors should be focused on technical issues such as product lines, evolving technologies and R&D efforts. Any pricing needed for our activities should be limited to budgetary estimates with no obligations for Entergy or vendors.

Your remarks were concluded with a request that we be sensitive to how busy our customers are and therefore provide convenient feedback in whatever form they request. For now, you suggested copying the Directors on meeting minutes, planning on a presentation somewhere at the midpoint of the Team's effort, and, of course, preparation of a final report and presentation.

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USE OF QUALITY PRINCIPLES AND TECHNIQUES

As Team Leader, I emphasized how important it is for each of the team members to:

- Be trained in and use Quality principles.
- Recognize that a full time on-line facilitator will be very helpful by providing impartial feedback and in keeping the Team focused on meeting our deliverables.
- Recognize that we must follow TQI processes understood by management as we work to deliver the expected results.

CONCERNS AND EXPECTATIONS

Each member of the Team was given a chance to express their individual expectations and concerns. These are listed below in the order they were voiced.

CONCERNS:

1. *"If we aren't careful, we will 're-invent the wheel'!"*
2. *"Will the Directors and Plant Managers buy in, especially if their favorite project is rank ordered lower on the list?"*
3. *"We better not forget about the 'end users'!"*
4. *"Rigid engineering standards don't work and they take away ownership if forced on people. What we need is some flexible policy guidelines, not strict engineering standards."*
5. *"I already have a full work schedule, how am I going to make time for this QAT?"*
6. *"After a system is installed, who is going to be responsible for design changes and accountable for good performance?"*
7. *"We don't have a System control 'philosophy' .... this is one of the first things we must develop!"*
8. *"The current estimates for control upgrades are probably way off from a realistic price tag. At best, they are 'order of magnitude' guesses and the proposed schedules are probably more inaccurate than the budget estimates."*
9. *"I am concerned that we will do a lot of work and the final report will just be filed away!"*
10. *"If the System spends as much for control upgrades as currently projected, there is going to be great funding competition with other projects."*

EXPECTATIONS:

- Directors and Plant Managers can expect the Team to be customer-sensitive.
- Management buy-in for recommendations is expected at the Director and Plant Manager level.
- Plant Managers are expected to support system needs (in regard to the rank-ordering of control upgrades).

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GROUND RULES

After the discussion of expectations and concerns, we developed a set of Ground Rules that should ensure that our QAT stays on track and avoids pitfalls. These Ground Rules are listed below in the order that they were developed.

1. Bob Tanis will provide strategic direction, Lewis will provide leadership, and Mona will provide expertise as an unbiased senior facilitator .

2. Issues not related to System Plant Control Upgrades (e.g. Engineering Organizations) will not be a topic of discussion during QAT business.

3. All team members pledged to be objective and avoid protecting local "turf".

4. Any team member can "FIDO" a topic that he thinks should go on the "Parking Lot". At that point, the topic will go on the Parking Lot to be dealt with later.

5. Breaks will be frequent but relatively short.

6. In dealings with Vendors:

   - We will make a special effort to keep everything we do above reproach.
   - When approaching vendors for information, the contact will be made by a team member not familiar with the vendor.
   - Any processes developed regarding vendors will be "generic" so as to avoid favoritism.
   - QAT proceedings will not be shared with vendors.

DELIVERABLE CLARIFICATION

Over three hours was spent in efforts to better define the deliverables expected from this QAT. Several of the expected results contained in the QAT charter have been reworded slightly. The team feels that the new wording will be an improvement and will proceed as stated below unless our Customers see a problem. Following are the QAT deliverables and a short explanation of what the Team plans on doing to produce each deliverable. When the wording of a deliverable has been changed, both the old and new wording will be shown.

1. A SYSTEM DOCUMENT (AND ACCOMPANYING PROCESS FLOWCHART) THAT CONTAINS OVERALL GUIDANCE ON BALANCING BUSINESS, TECHNICAL AND O&M CONSIDERATIONS FOR CONTROL UPGRADE DECISIONS.

This deliverable must serve as the "umbrella" document to cover all involved personnel and processes. The five other deliverables will rely on this item, although the final format and content for the process document will no doubt be developed in parallel with other deliverables.

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2. A DATA BASE OF EXISTING CONTROLS AND DATA ACQUISITION SYSTEMS CURRENTLY IN USE ON THE SYSTEM'S UNITS AND THE MODIFICATIONS PLANNED IN THE FUTURE.

One of the first tasks of the QAT will be to decide what needs to be included in the data base and then work with ETS Technology Development to collect the necessary information on existing equipment. Team members will contact the plants to determine what control upgrade efforts the plants would like to get on the list for desired upcoming projects.

3. DEVELOP ENGINEERING STANDARDS TO PROVIDE GUIDANCE NECESSARY TO ASSURE TECHNICAL ADEQUACY AND OVERALL QUALITY OF FUTURE CONTROL UPGRADES.

--CHANGED TO--

3. DEVELOP ENGINEERING GUIDELINES NECESSARY TO ASSURE TECHNICAL ADEQUACY AND OVERALL QUALITY OF FUTURE CONTROL UPGRADES.

Engineering guidelines and policy, if wisely designed, will promote overall quality in the technical support of the fossil plants. To balance necessary standardization yet still promote ownership and initiative is the goal and the reason for selecting "guidelines" as opposed to "standards" as a key-word. A wealth of information is available from EPRI as well as from published articles by other utilities who are further along in control upgrades than Entergy.

4. DEVELOP CRITERIA FOR EVALUATION OF POTENTIAL VENDOR ALLIANCES.

--CHANGED TO--

4. DEVELOP CRITERIA FOR EVALUATION OF VENDOR ALLIANCE CONSIDERATIONS.

The team is not going to propose potential alliance partners. Rather, it will focus on characteristics of a beneficial alliance for Entergy. Criteria guidelines will be independent of any vendor. Furthermore, the "How" rather than the "Who" will be the issue. Economies of scale will be an important, but not the only, consideration.

5. DEVELOP A COST-BENEFIT METHODOLOGY TAILORED TO CONTROL PROJECTS THAT WOULD BE USED FOR FUTURE CONTROL UPGRADES.

--CHANGED TO--

5. DEVELOP AN EVALUATION METHODOLOGY (INCLUDING, BUT NOT LIMITED TO COST BENEFIT CONSIDERATIONS) TAILORED TO CONTROL PROJECTS WHAT WOULD BE USED FOR FUTURE CONTROL UPGRADES.

After considerable reflection and discussion, the Team realized that the System needs an overall evaluation process, not just another "cook-book" cost benefit spreadsheet. Definitive "dollar" costs and benefits are certainly an important component; however, some factors do not lend themselves to the assignment of a price tag. Because of the diversity of factors that will need consideration, the Team felt that a Kepner Tregoe methodology should be used.

The evaluation methodology will allow preparation of a relative ranking based on the factors unique to each project. A straightforward rank ordering and summary level statement of reasons

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for the ordering are necessary for presentation to Directors and Plant managers. With this information, the management team can set strategy and priorities.

The evaluation methodology will also support the preparation of definitive Budget Item packages in anticipation of design and installation work. This work should proceed after the management team provides guidance on which projects to pursue. This component of the process will recognize differences in Budget Item preparation between region and/or state.

6. DEVELOP A SUGGESTED ORDER TO IMPLEMENT PLANNED CONTROL UPGRADES FOR THE SYSTEM AND EACH REGION.

Based on the data collected in Deliverable 2 and the Kepner Tregoe evaluation to be accomplished in Deliverable #5, the list of planned control upgrades will be rank ordered for the system and each Region.

INDIVIDUAL EFFORT TO COMPLETE THE QAT

After the discussion on QAT deliverables, there was a better realization that this QAT will take a considerable amount of effort from each member of the team. This topic was discussed during one of the times that Randy Dufour was visiting. Randy emphasized to his employees that the QAT was a priority. The way things were left is for each individual to discuss schedule and resource conflicts with his supervisor and work out alternatives for his work.

INPUT/OUTPUT MODEL

The last hour of the meeting was devoted to developing an Input/Output Model to itemize, in detail, the tasks necessary to accomplish the Deliverables. This activity will be continued during Meeting 2. A process flow chart for QAT activities will also be developed during Meeting 2.

II. PLANT VISITS

The Team feels strongly about doing everything reasonably possible to get plant input. Toward this end, members of the Team will visit each plant in the System.

As a start toward this goal, John Booth, Nick Musmeci and I visited the Lake Catherine and Couch Plants on Oct. 16. The Honeywell data acquisition systems at these plants were inspected, along with other original controls. We were also able to talk to plant personnel and share with them what the QAT is about. It was also fortunate that the Plant Managers at both plants (Harvey Miller and Richard Rothwell) were on site and able to speak to us.

On Oct. 20, Lester Jenkins and I visited the Gerald Andrus and Delta plants. The objective of these visits was similar to the Couch and Lake Catherine visits except that these units still operate with original equipment. The emphasis was therefore on desired future upgrades. We were also able to talk to Rex Shannon and several members of the Gerald Andrus staff. Stan Prather of the Delta plant was not on site; however, we did have time to tour the plant and discuss the QAT with several members of the Delta staff.

As soon as possible, the other plants in the System will be visited.

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III. FUTURE MEETINGS & MEETING # 2 AGENDA

QAT LOGISTICS

The next six meeting days were scheduled during the first meeting. In order to minimize travel time, we decided to have back-to-back meetings on Thursday and Friday every other week, rotated among locations as follows:

October 22-23	New Orleans
November 5-6	Little Rock
November 19-20	Jackson

Additional meetings will be scheduled well in advance to help in making shuttle and hotel reservations

MEETING #2

LOCATION: TLC, conference room 33B
TIME: 9:30 AM

AGENDA:

1. Complete the Input/Output model.
2. Develop a process flow chart for Team activities.
3. Develop a schedule for Team activities.

cc:

Frank Gallaher (TLC 3301)	Mickey Cox (TLC 3310)
Jim Rider (TLC 3311)	Glenn Phillips (TLC 3312)
Randy Dufour (TLC 3213)	Mona Draper (TLC 2310)
John Booth (Lake Catherine Plant)	Steve Coker (ISES)
Lester Jenkins (MPL BOX 057)	Luis Maldonado (TLC 3213)
Nick Musmeci (TLC 3211)	I. B. Stewart (N107)

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ENTERGY POWER PLANT CONTROL UPGRADE QUALITY ACTION TEAM

PROCESS OWNER: Robert Tanis

TEAM LEADER:

Lewis Hirschy	(Plant Eng. Supervisor, Coal Ops., Independence Plant)

TEAM MEMBERS:

Mona Draper	(Senior Facilitator, Total Quality Improvement, New Orleans)
Lester Jenkins	(Engineer, ETS, Design Engineering, Miss.)
Nick Musmeci	(Engineer, ETS, Design Engineering, New Orleans)
Steve Coker	(Engineer, Coal Ops., Independence Plant)
I.B. Stewart	(Operations Superintendent, Southern Region, Michoud Plant)
John Booth	(Technical Support Supervisor, Northern Region, Lake Catherine Plant)
Luis Maldonado	(Supervisor, Maintenance Engineering & Standards, ETS, Design Engineering, New Orleans)

PRIMARY CUSTOMERS:
Power Plant Directors

TEAM "DELIVERABLES"

1. Develop a System Document (and accompanying process flowchart) that contains overall guidance on balancing business, technical and O&M considerations for control upgrade decisions.

2. Develop a data base of existing controls and data acquisition systems currently in use on the System's units and the upgrades planned in the future.

3. Develop engineering guidelines necessary to assure technical adequacy and overall quality of future control upgrades.

4. Develop criteria for evaluation of vendors.

5. Develop an evaluation methodology (including, but not limited to cost-benefit considerations) tailored to control projects that would be used for future control upgrades.

6. Develop a suggested order to implement planned control upgrades for the System and each Region.

ESTIMATED COMPLETION: March 1, 1993

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Tentative Timeline for Long-term Alternative Coal Evaluation

	Q1	Q2	Q3	Q4
Determination of project scope	Team from Fossil ops, Sys Ops and Fuel Supply assembled	Scope finalized		
Determination of fuel sources evaluated	Draft selection	Final selection - Burn Plan established		
Coal yard handling		Draft logistics and handling issues identified	Preliminary cost estimates developed	Detailed cost studies performed on promising alternatives
Boiler evaluation		Initial studies of boiler effects determined. Study plan for boiler identified.	External studies, if any, commissioned. Collect data from ongoing test burns.	Results from any external studies received.
Environmental considerations	Identify limitations on alternative fuels	Application for test burn for coals outside current permits		
Economic evaluation	Preliminary fuel forecast	In-depth fuel forecast	Integration of preliminary O&M and capital into overall fuel economics	Final economic analysis
Budget integration			Draft CapEx estimates identified	Budget CapEx and O&M integrated in budget process

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ETR_00002131

Recommendations - Coal Plant Reliability Team

Redacted

Rec. No.	Recommendation	Proposed Disposition	Process	Responsible Individual(s)
1	Perform more detailed CBO assessments utilizing in-house and/or industry SMEs by re-distributing funds.	Based upon Technical Support's desire to not be the "Policeman/Reporting Agent", Plant Management and the Region Directors will monitor the effectiveness of CBO Assessments, requesting assistance and technical support as required. Plant management to insure that CBA Teams meet routinely and have the appropriate team membership.	CBO	Region Directors Plant Managers
2	Perform thorough life assessments of major and critical components	Include in item 1 above--no further action required.	CBO	NA
3	Stay the course on BTFR/CCI	Continue current auditing and reporting--- no further action required.	CBO	NA
4	Follow OEM test recommendations for generator stator	Include in item 1 above -- no further action required.	CBO	NA
5	Develop a method to measure the quality of CBO assessments	Based upon Technical Support's desire to not be the "Policeman/Reporting Agent", Plant Management and the Region Directors will monitor the effectiveness of CBO Assessments, requesting assistance and technical support as required. Sabine template has been approved as a means of insuring consistency from site to site.	CBO	Region Directors Plant Managers
6	Perform life assessment on main transformers and exciters	Include in item 1 above -- no further action required.	CBO	NA
7	Charter team to evaluate CBO recommendations, measures, and ensure consistent implementation.	Region Directors and Plant Managers to work together to drive consistency through the use of CBO measures (See item 8 below). Technical Support is to work with OU to check and adjust the CBO Toolkit documentation as necessary. Sabine template has been approved as a means of insuring consistency from site to site.	CBO	Region Directors Plant Managers Charlie Weatherford
8	**CBO Measures** •Reduction in LMWhs due to improvement in CBO process assessments •Failures not anticipated by assessments •Reduction in LMWhs due to improvement in work quality •Track service hours relative to OEM recommendations and identify risks.	Region Directors and Plant Managers to work together to drive consistency through the use of CBO measures. Work with Business Support to develop any new measures required. Allow the use of measures to drive CBO consistency at this time. Technical Support to modify the RCA process documents to add questions for evaluating whether current assessments were sufficient. Plants to trigger RCA's for significant events as appropriate.	CBO	Al Gahn Region Directors Plant Managers Stan Jaskot

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9	Formal engineering study of timing and feasibility of economizer and duct replacement on WB/ISES units	Washington Group to be contracted to perform an analysis of the current condition of the economizers, hangers, and ductwork and to offer recommendations on replacement and associated cost estimates and schedule. This will be a followup action to work that has already been completed by Washington Group. Plants to own the project in the usual way, requesting support as needed. The replacement of economizers needs to be closely coordinated with plans for environmental modifications to optimize expenditures and schedules. Final output of the study to be a formal plan with associated budgetary cash flows.	ENGR	Region Directors Plant Managers Myra Glover Tom Schnatz Charlie Weatherford
10	Standardize the procedures and process of operator rounds to ensure effectiveness (electronic rounds)	Implement electronic rounds at ISES [redacted] using similar equipment and procedures to those currently in place at White Bluff.	OPER	Wayne Garrison Larry Ables
11	Continue Operator Qualification Process	Follow through on Operator Skills Team recommendations.	OPER	Wayne Garrison Larry Ables
12	Assign a work quality control resource during outages	Just do it! Consider using VRC resources if needed. Give good direction to the persons selected relating to potential areas of poor quality.	ORG	Wayne Garrison Larry Ables
13	Add one or more Fossil Reliability Engineers	Region Directors/Plant Managers to evaluate the need for reliability engineering resources and make a case for those resources as deemed appropriate.	ORG	Region Directors Plant Managers
14	Add Outage Planners for ISES and WB	No plan to implement at this time.	ORG	NA
15	Ensure that Plant Support Outage Superintendent gets involved in assessment/outage planning early in process	Follow planning requirements as published in CBO toolkit documentation to assign the Outage Supt. At least one year in advance.	ORG	Region Directors Plant Managers Tom Schnatz
16	Charter Six-Sigma team to analyze and optimize Planned outage duration	This item is being worked by the Outage Planning Peer Group and the Coal Plant Overtime Team, and we have an initiative underway to formally plan 10 critical outages. No additional actions are planned at this time.	ORG	NA
17	Ensure coal plants utilize qualified electrical repair shops for large motor repairs	Supply Chain to develop a list of approved vendors in concert with the plants and Technical Support. Give consideration to geographical proximity when selecting shops. Direct all repairs only to approved shops.	PROCUR	Randy King

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18	Develop a process to ensure all affected plants implement the recommendations which result from RCAs (TIL approach). Process should include someone with proper authority as owner.	Technical Support to develop a process to issue Fossil Information Letters (FIL??) as a result of discovery occuring during reliability related activities (CBO, RCA, RMP, etc.). Issue FIL's to all plants having similar equipment. Plants to track implementation of recommended changes.	RCA	Tom Schnatz Stan Jaskot Region Directors Plant Managers
19	Ensure all events, including accumulated derates > 10,000 LMWHs have RCAs (exclude planned outages) measure and report this performance	Memo has been issured by Etienne requiring this change. Technical Support is modifying the trending graphs to accomadate.	RCA	Tom Schnatz Stan Jaskot Region Directors Plant Managers
20	Add significant events as a trigger to the RCA process	Current reporting of RCA's by Technical Support is deemed to be appropriate. Plants have the option to assign other events (significant events) to RCA's if desired.	RCA	NA
21	Include SME review of RCA prior to plant manager approval to ensure quality	This recommendation will not be accepted based upon Technical Support's desire to not be the "Policeman/Reporting Agent", Plant Management and the Region Directors will monitor the effectiveness of RCA's, requesting assistance and technical support as required. Existing procedures require that RCA's be "suitable for discovery." It is Plant Management's responsibility to assemble the right teams and to produce RCA's of the appropriate quality.	RCA	NA
22	Implement software program to ensure consistent and thorough RCAs	Technical Support is performing another review of available software and will make recommendations as to whether or not one product should be accepted.	RCA	Tom Schnatz Stan Jaskot
23	Need a more user friendly RCA database that relates different information systems together (database should be searchable by key fields such as plant, unit, OEM, etc.)	Fossil IT to evaluate the potential to modify the existing database to meet the suggested needs and/or to estimate the cost of developing a new database --this needs to be added to our list of projects which are not initiatives but which may be worked in 2005	RCA	Elaine Dearborne Tom Schnatz Rick Fernandez
24	**RCA Measures** •Percent of RCAs triggered vs. RCAs completed (target is 100%) and posted on Web •Percent of RCA recommendations implemented (target is 100%) •Percent of RCAs reviewed by SMEs for quality	Region Directors and Plant Managers to work together to drive consistency through the use of RCA measures that are already available. Work with Business Support to develop any new measures required. Allow the use of measures to drive RCA consistency at this time. The quality check by the SME will not take place unless requested, based upon Technical Support's desire to not be the "Policeman/Reporting Agent". A page will be added to Tom Jasper's monthly report reflecting RCA performance.	RCA	Region Directors Al Gahn Plant Managers

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25	Develop a standard set of RMP measures/targets (include in HON) **RMP Measures** •Average response time by priority •Average number of days to complete a work request by priority •Work request priority override •Maintenance hours by equipment segmentation •Break-ins	Region Directors to work with Business Support to develop a summary RMP report to be presented periodically at the Plant Operations Work Session. Alllow the use of these high level measures to drive RMP consistency at this time. This report to contain the following metrics trended at 3 levels (1) Fossil, (2) Region, and (3) Plant: A. % of Maintenance Completed Manhours by shift employees B. PM Manhours as a % of Total Completed Maintenance Manhours C. Work Request Overrides as a % of Total Completed Work Requests D. Breakin Manhours as a % of Total Completed Maintenance Manhours E. Total Backlog Manhours F. % of Total Completed Maintenance Manhours Worked as Cycle Maintenance	RMP	Region Directors Al Gahn
26	Ensure personnel comply with RMP process via audits	Region Directors and Plant Managers to drive improvements in RMP consistency at sites identified as needing improvement by the monitoring of the metrics in item 25 above.	RMP	Region Directors Plant Managers
27	Perform detailed training of RMP processes to include roles and responsibilities	Region Directors and Plant Managers to drive improvements in RMP consistency at sites identified as needing improvement by the monitoring of the metrics in item 25 above.	RMP	Region Directors Plant Managers
28	Perform detailed training of AIMM	Region Directors and Plant Managers to drive improvements in RMP consistency at sites identified as needing improvement by the monitoring of the metrics in item 25 above.	RMP	Region Directors Plant Managers
29	Need POLT sponsorship of AIMM	Region Directors and Plant Managers to drive improvements in RMP consistency at sites identified as needing improvement by the monitoring of the metrics in item 25 above.	RMP	Region Directors Plant Managers
30	Build standard AIMM hierarchy applicable to all plants	This recommendation will be evaluated as a potential ECI project.	RMP	POLT
31	Ensure affected personnel understand the RMP process and know how to use it	Region Directors and Plant Managers to drive improvements in RMP consistency at sites identified as needing improvement by the monitoring of the metrics in item 25 above.	RMP	Region Directors Plant Managers

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32	Ensure future initiatives that impact RMP follow the RMP guidelines (e.g. critical alarms and SRCM)	Region Directors and Plant Managers to drive improvements in RMP consistency. Region Directors to provide representation of RMP considerations at the POLT as new initiatives are discussed.	RMP	Region Directors Plant Managers
33	Evaluate PMs for critical components (part of RMP)	Region Directors and Plant Managers to drive improvements in RMP consistency at sites identified as needing improvement by the monitoring of the metrics in item 25 above.	RMP	Region Directors Plant Managers
35	Ensure coal plants have implemented recommendations from 2000 Reliability Sub Teams and review annually	Region Directors and Plant Managers to drive improvements in RMP consistency at sites identified as needing improvement by the monitoring of the metrics in item 25 above.	RMP	Region Directors Plant Managers
36	Charter teams to evaluate RMP recommendations, measures, and ensure consistent implementation.	Region Directors and Plant Managers to drive improvements in RMP consistency at sites identified as needing improvement by the monitoring of the metrics in item 25 above.	RMP	Region Directors Plant Managers

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Recommendations - Coal Plant Reliability Team

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Rec. No.	Recommendation	Proposed Disposition	Process	Responsible Individual(s)
1	Perform more detailed CBO assessments utilizing in-house and/or industry SMEs by re-distributing funds.	Technical Support to develop a report reflecting assessment performance by plant and by region and present this report quarterly at the Plant Operations Working Session for Region Director followup.	CBO	Tom Schnatz Stan Jaskot
2	Perform thorough life assessments of major and critical components	Include in item 1 above	CBO	NA
3	Stay the course on BTFR/CCI	Continue current auditing and reporting	CBO	NA
4	Follow OEM test recommendations for generator stator	Include in item 1 above	CBO	NA
5	Develop a method to measure the quality of CBO assessments	Modify the CBO process to require signoff by Tech Supp Specialist and Plant Manager before assessment is counted in item 1 above	CBO	Tom Schnatz Stan Jaskot
6	Perform life assessment on main transformers and exciters	Include in item 1 above	CBO	NA
7	Charter team to evaluate CBO recommendations, measures, and ensure consistent implementation.	Postpone any action here until items 1 & 5 above are accomplished and working. Keep on list for future initiative.	CBO	Elaine Dearborne
8	**CBO Measures** •Reduction in LMWhs due to improvement in CBO process assessments •Failures not anticipated by assessments •Reduction in LMWhs due to improvement in work quality •Track service hours relative to OEM recommendations and identify risks.	Add a selection choice in GADRS to indicate that an outage should have been avoided by CBO activities. This would be similar to the current selection choice to indicate a boiler tube failure. This will simplify future analysis.	CBO	Al Gahn Tom Jasper
9	Formal engineering study of timing and feasibility of economizer and duct replacement on WB/ISES units	Washington Group to be contracted to perform an analysis of the current condition of the economizers, hangers, and ductwork and to offer recommendations on replacement and associated cost estimates and schedule. This will be a followup action to work that has already been completed by Washington Group. Plant Support to lead this effort with assigned plant involvement. Final output of the study to be a formal plan with associated budgetary cash flows.	ENGR	Tom Schnatz Charlie Weatherford
10	Standardize the procedures and process of operator rounds to ensure effectiveness (electronic rounds)	Implement electronic rounds at ISES and [redacted] using similar equipment and procedures to those currently in place at White Bluff	OPER	Wayne Garrison Larry Ables
11	Continue Operator Qualification Process	Follow through on Operator Skills Team recommendations	OPER	Region Directors
12	Assign a work quality control resource during outages	Just do it! Consider using VRC resources if needed.	ORG	Wayne Garrison Larry Ables

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13	Add one or more Fossil Reliability Engineers	Technical Support to add at least one Reliability Engineer to monitor the performance and effectiveness of our overall reliabiltiy efforts and to recommend modifications to our strategies and methods.	ORG	Tom Schnatz Stan Jaskot
14	Add Outage Planners for ISES and WB	Add an outage planner to the ISES and WB organizations, reporting directly to the Production Supt. Eliminate positions elsewhere in the organization to avoid increasing total Fossil staffing.	ORG	Wayne Garrison
15	Ensure that Plant Support Outage Superintendent gets involved in assessment/outage planning early in process	Assign this responsibility to the new outage planners created in item 14 above	ORG	Wayne Garrison
16	Charter Six-Sigma team to analyze and optimize Planned outage duration	Add to the list of potential six sigma projects. Priortize and work when appropriate.	ORG	Elaine Dearborne
17	Ensure coal plants utilize qualified electrical repair shops for large motor repairs	Supply Chain to develop a list of approved vendors in concert with the plants and Technical Support. Give consideration to geographical proximity when selecting shops. Direct all repairs only to approved shops.	PROCUR	Randy King
18	Develop a process to ensure all affected plants implement the recommendations which result from RCAs (TIL approach). Process should include someone with proper authority as owner.	Technical Support to develop a process to issue Fossil Information Letters (FIL??) as a result of discovery occuring during reliability related activities (CBO, RCA, RMP, etc.). Issue FIL's to all plants having similar equipment and track implementation of recommended changes. Report compliance status annually at the Plant Operations Working Session.	RCA	Tom Schnatz Stan Jaskot
19	Ensure all events, including accumulated derates > 10,000 LMWHs have RCAs (exclude planned outages) measure and report this performance	Technical Support to modify/develop a report reflecting RCA performance by plant and by region and present this report quarterly at the Plant Operations Working Session for Region Director followup.	RCA	Tom Schnatz Stan Jaskot
20	Add significant events as a trigger to the RCA process	Modify the RCA process to specifically include significant events as a trigger.	RCA	Tom Schnatz Stan Jaskot
21	Include SME review of RCA prior to plant manager approval to ensure quality	Modify the RCA process to require signoff by Tech Supp Specialist and Plant Manager before report is counted in item 19 above	RCA	Tom Schnatz Stan Jaskot
22	Implement software program to ensure consistent and thorough RCAs	Evaluate the software package used recently by GE in doing the RCA on the [redacted] outage for applicability to all Fossil RCA's. If acceptable, procure rights to program, provide required training to Plant Operations personnel, and roll out -- this (or some alternative) needs to be added to our list of potential 2005 initiatives	RCA	Elaine Dearborne

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23	Need a more user friendly RCA database that relates different information systems together (database should be searchable by key fields such as plant, unit, OEM, etc.)	Fossil IT to evaluate the potential to modify the existing database to meet the suggested needs and/or to estimate the cost of developing a new database --this needs to be added to our list of projects which are not initiatives but which may be worked in 2005	RCA	Elaine Dearborne
24	**RCA Measures** •Percent of RCAs triggered vs. RCAs completed (target is 100%) and posted on Web •Percent of RCA recommendations implemented (target is 100%) •Percent of RCAs reviewed by SMEs for quality	These metrics should be included in the report developed for item 19 above	RCA	Tom Schnatz Stan Jaskot
25	Develop a standard set of RMP measures/targets (include in HON) **RMP Measures** •Average response time by priority •Average number of days to complete a work request by priority •Work request priority override •Maintenance hours by equipment segmentation •Break-ins	Fossil IT to develop a summary RMP report to be presented at each Plant Operations Work Session. This report to contain the following metrics trended at 3 levels (1) Fossil, (2) Region, and (3) Plant: A. % of Maintenance Completed Manhours by shift employees B. PM Manhours as a % of Total Completed Maintenance Manhours C. Work Request Overrides as a % of Total Completed Work Requests D. Breakin Manhours as a % of Total Completed Maintenance Manhours E. Total Backlog Manhours F. % of Total Completed Maintenance Manhours Worked as Cycle Maintenance	RMP	Tom Schnatz Rick Fernandez
26	Ensure personnel comply with RMP process via audits	Select an audit team and perform audits at sites identified as needing improvement by the monitoring of the metrics in item 25 above -- this needs to be added to our list of projects which are not initiatives but which may be worked in 2005	RMP	Elaine Dearborne
27	Perform detailed training of RMP processes to include roles and responsibilities	Select a team to perform training at sites identified as needing improvement by the monitoring of the metrics in item 25 above -- this needs to be added to our list of projects which are not initiatives but which may be worked in 2005	RMP	Elaine Dearborne
28	Perform detailed training of AIMM	included in item 27 above	RMP	NA
29	Need POLT sponsorship of AIMM	Appoint POLT member to be AIMM/RMP Sponsor	RMP	Mike Bakewell

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30	Build standard AIMM hierarchy applicable to all plants	Use POLT sponsor identified in item 29 to facilitate and encourage standardization by moving plants toward similar heirarchies with similar numbers of components where appropriate.	RMP	Region Directors
31	Ensure affected personnel understand the RMP process and know how to use it	included in item 27 above	RMP	NA
32	Ensure future initiatives that impact RMP follow the RMP guidelines (e.g. critical alarms and SRCM)	Appointing a POLT sponsor should provide for appropriate RMP considerations during initiative development process	RMP	NA
33	Evaluate PMs for critical components (part of RMP)	included in item 26 above	RMP	NA
35	Ensure coal plants have implemented recommendations from 2000 Reliability Sub Teams and review annually	included in item 26 above	RMP	NA
36	Charter teams to evaluate RMP recommendations, measures, and ensure consistent implementation.	included in item 26 above	RMP	NA

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Unit Ranking based on Reliability as well as Economics

Tier	Unit	1% Improvement Savings ($)	Max Capability	MWh Generation
1	INDEPENDENCE #1	1,013,756	836	5,074,542
1	INDEPENDENCE #2	863,046	842	5,126,339
1	WHITE BLUFF #1	696,903	815	5,544,218
1	WHITE BLUFF #2	490,721	844	4,446,090

Important units due to reliability considerations

Unit	Rank (1 - 4) 1 is very critical

* These units are bolded in the list to the left.

** The above ranking is independent from the tier r
A rank of two above does not necessarily mean a

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anking.
a tier of 2 on the left.

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Team	Description of Recommendation	Diagnostics	Manhours	Equipment	Skills
Boiler Air & Gas	FD and ID fans - vibration, visual check dampers	**P**			
	Inspection of journals / bearings for clearance, wear, seal leakage, sludge	**S**			
	Inspection infrared scan of casing leaks for leaks, condition, hot spots	**P**			
	Inspection infrared scan of shaft seals for leaks, condition, hot spots	**P**			
	Identify & share plant O&M best practices & diagnostics	**S**			
	Establish PDM triggers in CBO	**P**			
Generator/Exciter	**On slip rings & commutators, perform monthly inspections to include the following:** Place the vibration probe on the OD of each brush. Measure the brush vibration. Acceptable brush vibration is not to exceed 1.0 - 1.5 mils above the vibration of the shaft.	**P**			
	Plant Support diagnostic groups to develop slip ring and commutator vibration program	**P**			
Boiler Feed Pump	**Vibration Diagnostics at Minimum Flow** - vibration data be collected at minimum flow conditions at least once very six months for internal wear determination and trending	**P**			
	EPRI resource documents - the following EPRI reports be purchased for P**lants & Plant Support Offices:** Boiler Feedpump Operation and Maintenance Guidelines Volume 1: Troubleshooting (TR-104292-V1); Boiler Feedpump Operation and Maintenance Guidelines Volume 2: Case Studies (TR-104292-V2). **For Plant Support Offices:** Periodic Vibration Monitoring: Utility Experience (CS-5517).	**S**			
	Continuous vibration monitoring - [redacted]	**S**			
	PM/PDM:				
	Discharge check valve every 5 years or more frequently based upon conditions Internal inspection - borescope inspection possible option	**S**			
	Rotating element vibration every 6 weeks / every 3 weeks (w/alarm in) Collecting vibration data from bearing caps using hand held accelerometers and from proximity probes (if available). Trending data for 6 parameter bands and reporting results.	**P**			
	Rotating element vibration at min flow every 6 months Collecting vibration at minimum flow operation	**P**			
	Rotating element triggered analysais - triggered by: vibration levels above alarm 2 level Collecting additional vibration data (I.e. phase, orbits, variable speeds) and other pertinent data (I.e. bearing temperatures, etc) and then analyzing data and reporting results of probable cause and recommendations. Utilize EPRI tables as resource.	**P**			

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Team	Description of Recommendation	Diagnostics	Manhours	Equipment	Skills
Boiler Feed Pump Cont'd	**Lube oil system quarterly** Collecting oil samples from bearing oil return line, reservoirs and conditioning filter outlet for analysis (internal or external) checking for: water content, particle count, wear metals, additives, physical properties. Reporting results, recommendations and creating needed WRs.	S			
	Bearings - triggered-elevated radial vibration (above alarm 2) with vibration spectrum indicating excessive clearance / elevated bearing temps w/o other cause / thrust wear indicator change or alarm Bearing radial & thrust disassembly, inspeciton, dimensional checks (with documentation), reassembly	S			
	Coupling-all types - triggered-elevated vibration (above alarm 2) indicating alignment problems / operator walkdown observing problem / historical or experience base Coupling disassembly / inspection / reassembly - alignment check	S			
Electric Motor Failures	**PM / PDM programs**				
	Review techniques that will provide data in a timely manner to assist with CBO assessments for outage planning On-line testing supplies data under actual loaded conditions and provides: Power condition Motor condition, performance and load Vibration	P			
	Standardization of diagnostic testing, procedures, equipment, reporting and recommendations Testing is relevant to the consistency of application of voltages over time Safeguards on the latest equipment prevents component damage from overcurrent	P			

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Team	Description of Recommendation	Plant Support										
		Diagnostics	Performance	Engineering	Technical Support	Outage Management	Drafting	Business Support	Plant	Operation University	Supply Chain	Needs Further Development
Feedwater Heater	Plug "at-risk" tubes identified by Eddy current testing NDE								P			
	Explosive plugging on HP FWHs								P			
	EPRI level control / alarm guidelines			S		S			P			
	Apply specs for purchase and repair			S					P		S	
	Pilot - determine best early leak detection scheme											X
	Diagnostic / performance trend DCA, TTD, delta T								S			X
	Tube failure mapping in TRACS, integrated w/AIMM						S		P			
	Blow-out instrument manifolds								P			
	Verify extraction and NRV above & below seat drains are clear / open								P			
	Monitor normal drain control valve position								P			
	Limit running with leaks; isolate to extent possible								P			
	Consistently use startup venting capabilities								P			
	Hydro for leaks								P			
	Review FWH OEM operation manuals								P			
Boiler Air & Gas	[redacted]			[redacted]					[redacted]			
	[redacted]			[redacted]					[redacted]			
	ISES & WB - ID fan variable pitch blade controls enclosure upgrade								P			
	[redacted]			[redacted]								
	White Bluff 1 - replace air preheater cold end baskets								P			
	FD and ID fans - vibration, visual check dampers	P							S			
	Air preheaters - motor amps / balance								P			
	Dampers - visual check								P			
	Inspection of wheel (rotor) for cracks, dirt, wear					S			P			
	Inspection of journals / bearings for clearance, wear, seal leakage, sludge	S							P			

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Team	Description of Recommendation	Plant Support										
		Diagnostics	Performance	Engineering	Technical Support	Outage Management	Drafting	Business Support	Plant	Operation University	Supply Chain	Needs Further Development
Boiler Air & Gas Cont'd	Inspection, lubrication of inlet dampers for dry bearings, looseness, ball joint wear and lubrication								P			
	Inspection of outlet dampers for operation 100% open and closed								P			
	Inspection of gear box for leaking seals, worn gears, clearances								P			
	Check balance of rotor motor amps, free wheeling rotor					S			P			
	Inspection of pin rack to check for wear								P			
	Inspection of bull gears to check for wear								P			
	Inspection of radial / circumferential seals for clearance and wear								P			
	Inspection of baskets for condition of internals, looseness, support structure								P			
	Inspection of expansion joints for leaks, condition								P			
	Inspection infrared scan of casing leaks for leaks, condition, hot spots	P										
	Inspection infrared scan of shaft seals for leaks, condition, hot spots	P							S			
	Check FD/ID fans bearings twice a shift for vibration, water, dirt, leaks								P			
	Check FD/ID fans lubrication twice a shift for oil in sight glass, leaks								P			
	Check FD/ID fans damper drives / linkage twice a shift for lubrication, looseness, position								P			
	Check FD/ID fans motor amps every week for high or low amps								P			
	Check air preheaters gear box oil level twice a shift for quality and cleaness of oil								P			
	Check air preheaters for excess vibration twice a shift for low frequency vibration								P			
	Check air preheaters for unusual noise twice a shift from gear box or internal air heater								P			
	Check air preheaters for air leaks at shaft for hot gases from behind bearings or casing								P			
	Status of fan continuous vibration monitoring systems								P			
	Continue EPRI search for proven strategies of fan repair, design											X
	Establish OEM communications for support and recommendations Alan Trux - Barron Industries, fan consultant & service Ormand Grizzle & Harry Campbell - APH consultants & service Implement contractor APH inspection & report every major outage (approx cost $3800 per insp								P		S	

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ETR_00002691

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Team	Description of Recommendation	Plant Support: Diagnostics	Performance	Engineering	Technical Support	Outage Management	Drafting	Business Support	Plant	Operation University	Supply Chain	Needs Further Development
Boiler Air & Gas Cont'd	Conduct FD fan accountability study-identify crucial fans based on design, materials, welds, field experience, age, unit role, etc.				P							
	Identify & restore plant proven PM's & PDM's								P			
	Identify & share plant O&M best practices & diagnostics	S							P			
	Establish System BAG technical resource pool - Meyer, Signorelli, DeRoche, Reamey, others				P							
	Establish Component Champions tied to CBO process								P			
	Establish PM triggers in CBO								P			
	Establish PDM triggers in CBO	P										
	Develop criteria for fan continuous vibration monitoring											X
	Implement system team - boiler inspection & walk down: All areas of boiler What needs to be fixed now? Long term needs and budget								P			
Boiler Pressure Part	**Conduct routine blr inspec during scheduled blr outages every 12-18 mths:** Use a Boiler OEM or other qualified source - following described process Inspections and associated testing driven by failure history and prior inspections Team has described 3 levels of inspections and associated tests & anticipated costs Team has listed types of NDE and tube sample tests					S			P			
	Boiler Reliability Details located at OU homepage									P		
	Implement routine mapping of boiler failures								P			
	RMP / outage assessment interface: Ensure mapping is done following maintenance Ensure work requests capture outage inspection report recommendations					S			P			
	Outage planning and budgets: Fix what's broke and get Technical Support help on planning Outage Assessment Team!				S				P			
	Operate boilers within design: SH/RH temperatures (tilts and sprays operational if designed) Water chemistry Turbine and auxiliary equipment performance?								P			
	OIS diagnostic monitoring tool to gauge boiler health and condition in development				S				P			

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Team	Description of Recommendation	Plant Support										
		Diagnostics	Performance	Engineering	Technical Support	Outage Management	Drafting	Business Support	Plant	Operation University	Supply Chain	Needs Further Development
Boiler Pressure Part Cont'd	**Consider value of replacement vs. partial repair:** If possible get Signorelli involved in your problems and outage scope development				S				P			
Generator/Exciter	**On all slip rings & commutators, perform weekly inspections (brush runs), to include the following:** General contamination by grease, filter material, water or carbon dust Brush chipping or arcing Brush length-replace individual brushes where there is less than 1/4" between the top of the holder box and the pigtail attachment point. The pigtail is normally attached via a rivet. When the rivet is 1/4 away from the top of the box, replace the brush. Brush pigtails for fraying, broken strands, excessive movement, or arcing By pulling each pigtail against its springs, ensure that each brush is free to move in the holder Verify the condition of air filters								P			
	On slip rings & commutators, perform monthly inspections to include the following: Place the vibration probe on the OD of each brush. Measure the brush vibration. Acceptable brush vibration is not to exceed 1.0 - 1.5 mils above the vibration of the shaft.	P										
	Verify, as possible, that the ground detection system is operational With a strobe light, examine commutators & slip rings for burning, streaking or photographing								P			
	On Siemens/Westinghouse brushless exciters, perform monthly inspections to include: Look for evidence of contamination by water, oil, or other foreign material, especially in the diode wheels Examine the condition of the taped banding for fraying or splitting Check the condition of the rotating elements, especially the blown fuse indicator Verify, as possible, that the ground detection system is operational Verify the integrity of lead wire to the slip rings Inspect the brushes, solenoid and slip rings Check for water leakage on air coolers								P			
	Improper exciter balance and coupling alignment recommendations: Use the latest OEM recommendations on coupling alignment and settings Swing checks must be done anytime brushless exciter coupling is broken					S			P			
	Corrective actions should be taken for vibration levels of 5 mils or greater at full load								P			

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Team	Description of Recommendation	Plant Support: Diagnostics	Plant Support: Performance	Plant Support: Engineering	Plant Support: Technical Support	Plant Support: Outage Management	Plant Support: Drafting	Plant Support: Business Support	Plant	Operation University	Supply Chain	Needs Further Development
Generator/Exciter Cont'd	**Equipment and housekeeping checklists:** Use equipment checklists from generator/exciter OEM's & Alliance partners to insure equipment is correctly assembled Use housekeeping lists to insure equipment is free of loose parts					S			P			
	Brush holder recommendations: Within one year, inspect all existing brush holders to determine type Within five years, replace all adjustable pressure holders with constant pressure type available from GE and Helwig								P			
	Plant Support diagnostic groups to develop slip ring and commutator vibration program	P										
	[redacted] Siemens Westinghouse to recommend design modification								[redacted]			
	Retaining ring issues: OEM recommendation in 1984 was to perform rings off testing within 5 years OEM's recommend immediate inspection of 18-5 rings when moisture intrusion is experienced Entergy is not currently implementing OEM program for rings off testing, we are instead using Raytheon to do rings on testing								P			
	During the next unit outage, but not to exceed 5 years: [redacted]					[redacted]			[redacted]			
	Add device 41 (field breaker) PM to outage breaker maintenance work								P			
Boiler Feed Pump	**BFP Spare Elements** - have spare elements repaired in a timely fashion to support reliability								P			
	Vibration Diagnostics at Minimum Flow - vibration data be collected at minimum flow conditions at least once very six months for internal wear determination and trending	P										
	Hand held vibration meter for plant personnel - each site have a hand held meter equal to or better than the Metric Instrument Model 5160DV								P			

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Team	Description of Recommendation	Plant Support										
		Diagnostics	Performance	Engineering	Technical Support	Outage Management	Drafting	Business Support	Plant	Operation University	Supply Chain	Needs Further Development
Boiler Feed Pump Cont'd	**EPRI resource documents** - the following EPRI reports be purchased for P**lants & Plant Support Offices:** Boiler Feedpump Operation and Maintenance Guidelines Volume 1: Troubleshooting (TR-104292-V1); Boiler Feedpump Operation and Maintenance Guidelines Volume 2: Case Studies (TR-104292-V2). **For Plant Support Offices:** Periodic Vibration Monitoring: Utility Experience (CS-5517).	S							P			
	Continuous vibration monitoring - [redacted]	[redacted]							[redacted]			
	Workmanship quality - shop repairs - choose repair shops and contracted on-site labor from proven vendors. Also, detailed overhaul procedures should be used for every inspection and overhaul of a feedpump.								P			
	Operational checks: Visual inspection per shift for leakage oil, water, steam, etc./packing around BFP & valves Vibration per shift for high vibration on piping, floor, turning gear bearing, auxiliary equipment Process conditions per shift for pump pressures; suction / discharge / seal water / seal water strainer dP. Pump temperatures: bearing metal / bearing / bearing drain / bearing supply / reservoir / seal water Lubrication system per shift for lubrication sys: brg flow indicators / visual oil indications / reservoir level / filter dP's / lube oil pressures Mechanical per shift for mechanical checks: thrust wear / rotor position indicators / coupling / coupling guard / pump mounting bolts / pipe hangers & supports / insulation / seal water drain / seal water collection tank level / valves & operators								P			
	PM/PDM: **Lube oil system bi-annually or more frequently if triggered based on condition for clean reservior / oil coolers** Visually inspection reservoir: piping / flanges / pump suction screens / internal relieves / internal check valves / hangers / lube oil pump / foreign objects / cleaniness / water / rust Visually inspection coolers: cooler tubes (both oil & water sides) Test coolers Visual check lube oil motors & coolers Recondition lube oil filter system (I.e. change out bowser filters, etc) Test run EBOP for BFP and oil pressure switches								P			

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ETR_00002695
Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Redacted

Team	Description of Recommendation	Plant Support										
		Diagnostics	Performance	Engineering	Technical Support	Outage Management	Drafting	Business Support	Plant	Operation University	Supply Chain	Needs Further Development
Boiler Feed Pump Cont'd	**Pump triggered by condition base - using historical and operating parameters (not expected to meet needs for next run cycle)** Pump overhaul - complete disassembly, inspection, repair, and reassembly to like new condition per new pump specifications								P			
	Discharge check valve every 5 years or more frequently based upon conditions Internal inspection - borescope inspection possible option	S							P			
	Rotating element vibration every 6 weeks / every 3 weeks (w/alarm in) Collecting vibration data from bearing caps using hand held accelerometers and from proximity probes (if available). Trending data for 6 parameter bands and reporting results.	P										
	Rotating element vibration at min flow every 6 months Collecting vibration at minimum flow operation	P										
	Rotating element triggered analysais - triggered by: vibration levels above alarm 2 level Collecting additional vibration data (I.e. phase, orbits, variable speeds) and other pertinent data (I.e. bearing temperatures, etc) and then analyzing data and reporting results of probable cause and recommendations. Utilize EPRI tables as resource.	P										
	Lube oil system quarterly Collecting oil samples from bearing oil return line, reservoirs and conditioning filter outlet for analysis (internal or external) checking for: water content, particle count, wear metals, additives, physical properties. Reporting results, recommendations and creating needed WRs.	S							P			
	Pump Performance - 8000 service hours and/or post pump overhaul Collecting test data at min of two load points, calculating results and reporting TDH deviation, flow and seal water flow trends. Balance leak off flow.		P									
	Bearing cap vibration - triggered-shift surveillance of pump vibration performance For BFP without continuous vibration monitoring. Hand held overall vibration reading and recording results in AIMM by plant personnel. If > 2mils or > 0.5 in/s at bearing cap, report to plant management for resolution.								P			
	Bearings - triggered-elevated radial vibration (above alarm 2) with vibration spectrum indicating excessive clearance / elevated bearing temps w/o other cause / thrust wear indicator change or alarm Bearing radial & thrust disassembly, inspeciton, dimensional checks (with documentation), reassembly	S							P			

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Redacted

Team	Description of Recommendation	Plant Support										
		Diagnostics	Performance	Engineering	Technical Support	Outage Management	Drafting	Business Support	Plant	Operation University	Supply Chain	Needs Further Development
Boiler Feed Pump Cont'd	**Coupling-all types - triggered-elevated vibration (above alarm 2) indicating alignment problems / operator walkdown observing problem / historical or experience base** Coupling disassembly / inspection / reassembly - alignment check	S							P			
	Instrumentation - vibration - triggered by: non-functioning outputs / pump overhaul / non-concurrence of vibration readings from Plt Support monitoring Vibration instrumentation calibration / check outputs to control room and DAS / check alarm functionality								P			
	Instrumentation - recirculation - min flow / suction flow / suction pressure - triggered by: pump overheaul / time - bi-annual / excessive leak thru / performance degrade Functional check of min. flow rec. valve control system / pump sunction flow and pressure alarm, runbacks and trips								P			
	BFP isolation valves every 5 years Inspection and repair of isolation valves for 100% shut off for BFP repair								P			
Electric Motor Failures	**Records and documentation**											
	Conduct RCA on all motor failures segmented in AIM as "critical" in future								P			
	Request "most probable cause" documentation from repair facilities on all failures								P			
	Reinforcement of the use of AIM to capture data related to failures and costs									P		
	Enhance AIM's capability to associate historical data files, such as diag reports, to components											X
	Upgrade the generation availability data reporting system Project assessment underway, report due 4/1/2000 Estimated $550,000 - based on entire new platform							P				
	QA / QC and repair specs											
	Use an appropriate insulating process as it applies to the operating environment								P			
	Standardize the practice of referencing specification E601 - 706 in contractual form for motor repairs								P		S	
	Review of Entergy's specification for electric motor repair, specification no. E601 - 706 Originated from GSU power plant standards originally issued September 12, 1985 Comparison of EPRI and IEEE recommendations for repair and testing specifications				P							

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Redacted

Team	Description of Recommendation	Plant Support: Diagnostics	Performance	Engineering	Technical Support	Outage Management	Drafting	Business Support	Plant	Operation University	Supply Chain	Needs Further Development
Elect Mtr Failures Cont'd	**Comparison and publication of shop capabilities** Horsepower / voltage limitations Insulating facilties Diagnostic tests Machine shop Transportation / mobilization										P	
	Operating procedures											
	Review the effect auxiliary power reduction efforts are having on the lift expenctancy of critical motors 87,041 LMWH, 8% of total LMWH were "cycled" motors Useful life of components depends on two factors Severity of each application of stress, "load" Number of repetitions thereof, "cycles"				P							
	Raise the level of awareness of starting frequency and conditions versus motor life Out of phase voltages may reach 150% of line voltage Current in-rush may reach 10 times normal starting current				P							
	PM / PDM programs											
	Review techniques that will provide data in a timely manner to assist with CBO assessments for outage planning On-line testing supplies data under actual loaded conditions and provides: Power condition Motor condition, performance and load Vibration	P										
	Implement a comprehensive PM / PDM program as it is intended to be applied 12 generating companies participated Project cost per plant, $80,000 30 motors, 4 kv and above per company Savings in costs and forced outages exceeded $8M during the three year test period				P							
	Standardization of diagnostic testing, procedures, equipment, reporting and recommendations Testing is relevant to the consistency of application of voltages over time Safeguards on the latest equipment prevents component damage from overcurrent	P										

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Claim Withdrawn. Contains No CBI. 07/11/2016_YD

Redacted

Team	Description of Recommendation	Plant Support										
		Diagnostics	Performance	Engineering	Technical Support	Outage Management	Drafting	Business Support	Plant	Operation University	Supply Chain	Needs Further Development
Elect Mtr Failures Cont'd	**Five stations in our system did not have any failures recorded** Review best practices Motor heaters Motor analysis Vibration testing Lube oil analysis Inspection cycles											**X**

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Redacted

Unit Information						Short Term Plan					Long Term Plan				
Plant	Unit	Equipment	Subcomponent	95-98 Total LMWH	Root Cause/Comment	Short Term Repair Activity	Year Planned	Estimated Cost $	% Reduction	LMWH Impact	Long Term Repair Activity	Year Planned	Estimated Cost $	% Reduction	LMWH Impact
White Bluff	2	Airheater	Bearing	3,902											
White Bluff	2	Airheater	Lube Oil	91,353											
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]					[redacted]				

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Equipment	Subcomponent	Inspection Type	Frequency of Inspection	Cost of Inspection	Diagnostic Test	Diagnostic Description Field
Teams may choose to write a narrative of a PDM/PM program if they prefer. The matrix will be used after the fact.						
Notes						
Column A	Equipment Driver - Example Boiler Feed Pump or Waterwall					
Column B	Subcomponent of driver, example - BFP Recirc Valve, Waterwall Slope Tubes, Waterwall Upper Arch					
Column C	Inspection or overhaul involving outage or other major maintenance activity. Example - pump overhaul/inspection or boiler inspection.					
Column D	Recommended frequency of overhauls/inspections					
Column E	General cost estimate of overhauls/inspections.					
Column F	Tests associated with predicting and assessing condition of the particular subcomponent					
Column G	Comments related to the typical triggers or indications of pending failure.					

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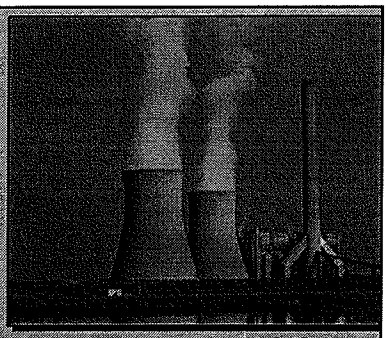
White Bluff Chemistry Department

Coal Lab Analysis



White Bluff and Independence Coal Analysis

This is a menu driven workbook, choose a topic button and click.

White Bluff

- Year to Date Analysis Summary
- Lab QA/QC Sample Precision Summary
- Lab QA/QC Accuracy Summary
- More to come !

Entergy

Independence

- Year to Date Analysis Summary

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1997

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White Bluff Plant
Unit Coal Analysis Summary

Entergy

Month	%AIR DRY LOSS	%TOTAL MOISTURE	% DRY SULFUR	% AS REC. SULFUR	DRY BTU/LB	AS REC. BTU/LB	% DRY ASH COMPOSITE	AS REC. LBS. SO_2/MBTU	SAMPLES ANALYZED	MONTHLY MWH	WBSES CAPACITY %
JAN.	9.09	28.30	0.543	0.389	12,073	8,655	#N/A	0.39	31	**918,134**	**74.49**
FEB.	11.65	28.49	0.586	0.419	12,046	8,615	#N/A	0.97	27	**666,495**	**59.88**
MAR.	11.97	28.49	0.552	0.394	12,063	8,627	#N/A	0.92	31	**948,334**	**76.90**
APR.	11.43	28.46	0.556	0.396	12,043	8,616	#N/A	0.92	30	**922,325**	**77.01**
MAY	11.11	28.48	0.606	0.433	12,008	8,588	#N/A	1.01	31	**956,223**	**77.48**
JUN.	10.62	29.23	0.579	0.409	11,965	8,469	#N/A	0.97	30	**953,844**	**79.79**
JUL.	10.43	28.07	0.486	0.349	12,021	8,647	#N/A	0.81	24	**997,156**	**80.81**
AUG.	9.84	27.81	0.533	0.384	12,015	8,675	7.63	0.89	31	**849,253**	**68.85**
SEP.	10.17	27.74	0.479	0.346	11,998	8,670	7.70	0.80	30	**736,619**	**61.69**
OCT.	10.81	27.51	0.578	0.419	12,055	8,739	#N/A	0.96	31	**463,995**	**76.27**
NOV.	9.81	28.17	0.570	0.409	12,136	8,716	#N/A	0.94	24	**474,709**	**80.90**
DEC.	11.03	28.55	0.639	0.457	12,205	8,720	#N/A	1.05	29	**589,997**	**48.11**
1997 YTD AVERAGE	**10.66**	**28.27**	**0.56**	**0.40**	**12,052**	**8,645**	**7.66**	**0.88**	**29**	**789,757**	**71.85**

ETR_00002772

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Entergy

White Bluff Coal Lab
QA/QC Sample Precision Summary

Month	%ADL to %TM (35%-45%)	%TOTAL MOISTURE WL=.106 CL=.300	% DRY SULFUR WL=.018 CL=.050	% AS REC. SULFUR WL=.018 CL=.050	DRY BTU/LB WL=18 CL=50	AS REC. BTU/LB WL=18 CL=50	% DRY ASH WL=.106 CL=.300	SAMPLES ANALYZED
JAN.	32.3%	0.036	0.004	0.003	11	8	#N/A	31
FEB.	41.0%	0.031	0.013	0.009	10	7	#N/A	27
MAR.	42.0%	0.024	0.005	0.000	5	0	#N/A	31
APR.	40.1%	0.035	0.004	0.003	6	4	#N/A	30
MAY	39.0%	0.033	0.003	0.002	6	4	#N/A	31
JUN.	36.2%	0.033	0.003	0.002	7	5	#N/A	30
JUL.	37.2%	0.337	0.005	0.004	9	6	#N/A	24
AUG.	35.3%	0.037	0.008	0.006	10	7	#N/A	31
SEP.	36.6%	0.031	0.006	0.004	8	6	#N/A	30
OCT.	39.3%	0.027	0.006	0.004	7	5	#N/A	31
NOV.	34.8%	0.022	0.003	0.002	11	8	#N/A	24
DEC.	38.7%	0.043	0.004	0.003	8	6	#N/A	29
1997 YTD AVERAGE	37.7%	0.057	0.005	0.004	8	6	#DIV/0!	29.1

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ETR_00002773

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1997

Entergy

White Bluff Coal Lab QA/QC
8-Mesh Round Robin Accuracy Summary

Entergy

Month	%TOTAL MOISTURE			% AS RECEIVED ASH			% AS RECEIVED SULFUR			DRY BTU/LB			AS RECEIVED BTU/LB		
	Known Value	Measured Value	Standard Deviation	Known Value	Measured Value	Standard Deviation	Known Value	Measured Value	Standard Deviation	Known Value	Measured Value	Standard Deviation	Known Value	Measured Value	Standard Deviation
JAN.	12.93	12.96	0.021	7.85	7.73	0.085	0.680	0.660	0.014	11,875	11,920	31.8	10,340	10,372	22.6
FEB.	29.97	30.05	0.057	5.77	6.37	0.424	0.340	0.310	0.021	11,683	11,700	12.0	8,183	8,183	0.0
MAR.	28.23	28.19	0.028	5.65	5.80	0.106	0.350	0.360	0.007	11,922	11,903	13.4	8,556	8,547	6.4
APR.	28.59	28.49	0.071	4.11	4.16	0.035	0.260	0.250	0.007	12,011	11,969	29.7	8,578	8,558	14.1
MAY	29.83	29.71	0.085	4.98	5.05	0.049	0.550	0.560	0.007	12,005	12,000	3.5	8,425	8,435	7.1
JUN.	27.01	27.05	0.028	4.17	4.20	0.021	0.160	0.150	0.007	12,123	12,136	9.2	8,842	8,854	8.5
JUL.	28.04	28.10	0.042	5.59	5.60	0.007	0.280	0.270	0.007	11,659	11,696	26.2	8,386	8,396	7.1
AUG.	29.99	30.00	0.007	4.97	5.02	0.035	0.330	0.310	0.014	11,781	11,822	29	8,248	8,275	19
SEP.	26.98	27.00	0.014	4.79	4.80	0.007	0.190	0.190	0.000	11,981	11,979	1	8,748	8,727	15
OCT.															
NOV.															
DEC.															
1997 YTD AVERAGE	26.84	26.84	0.039	5.32	5.41	0.086	0.349	0.340	0.011	11,893	11,903	17.4	8,701	8,705	12.5

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ETR_00002774

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Things to come at this site:

Bowl Mill analysis

Train analysis

- Jacob's Ranch
- North Antelope

If there are any other coal interest that you would care to see, please let us know.

White Bluff Chemistry Dept.
internal # 8-764-7158
external # 501-688-7158
fax # 501-688-7224

Claim Withdrawn. Contains No CBI. 07/11/2016_YD

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1997

Entergy

Independence Plant
Unit Coal Analysis Summary

Entergy

Month	%AIR DRY LOSS	%TOTAL MOISTURE	% DRY SULFUR	% AS REC. SULFUR	DRY BTU/LB	AS REC. BTU/LB	% DRY ASH COMPOSITE	AS REC. LBS. SO_2/MBTU	SAMPLES ANALYZED	MONTHLY MWH	ISES CAPACITY %
JAN.	8.36	28.39	0.243	0.174	12,170	8,715	N/A	0.40	9	N/A	N/A
FEB.	11.69	27.05	0.300	0.219	12,065	8,802	N/A	0.22	26	N/A	N/A
MAR.	11.22	27.03	0.283	0.206	12,017	8,769	N/A	0.47	22	N/A	N/A
APR.	12.01	27.46	0.286	0.207	12,481	8,811	N/A	0.48	25	N/A	N/A
MAY	10.47	27.84	0.283	0.204	12,006	8,664	N/A	0.47	27	N/A	N/A
JUN.	10.51	29.04	0.268	0.190	12,055	8,552	N/A	0.45	27	N/A	N/A
JUL.	11.21	28.74	0.273	0.195	11,884	8,458	N/A	0.46	17	N/A	N/A
AUG.	10.05	27.76	0.260	0.188	12,039	8,698	N/A	0.43	27	N/A	N/A
SEP.	9.71	27.08	0.257	0.187	12,108	8,828	N/A	0.42	27	N/A	N/A
OCT.	10.55	27.45	0.279	0.202	12,140	8,807	N/A	0.46	23	N/A	N/A
NOV.	10.32	26.98	0.272	0.199	12,000	8,759	N/A	0.45	20	N/A	N/A
DEC.	10.65	27.57	0.301	0.218	12,010	8,699	N/A	0.50	26	N/A	N/A
1997 YTD AVERAGE	**10.56**	**27.70**	**0.275**	**0.199**	**12,081**	**8,714**	**N/A**	**0.44**	**23**	**N/A**	**N/A**

ETR_00002776

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ISES COAL ANALYSIS

TO MENU	SAMPLE NO.	IS08801	IS08802	IS08803	IS08804	IS08805	IS08806	IS08807	IS08808	IS08809
SAMPLE INFO:	SAMPLE WT.	30	22	29	27	32	36			31
	DATE RECEIVED:	5-Aug	5-Aug	10-Aug	10-Aug	10-Aug	17-Aug			17-Aug
	ANALYSIS DATE:	6-Aug	6-Aug	13-Aug	13-Aug	13-Aug	18-Aug			18-Aug
	COMMENTS:									
	CHEMIST:	TJ	TJ	TJ	TJ	TJ	TJ			TJ
ADL	COAL & PAN:	1715.7	1654.7	1628.8	1670.2	1637.2	1644.8			1693.3
	TARE:	637.8	631.4	631.6	639.4	631.3	636.0			637.2
	DRY COAL & PAN:	1597.4	1538.1	1532.0	1559.8	1538.5	1534.2			1570.9
MOISTURE	COAL & CAP: (1)	30.3743	28.2679	30.5508	28.1484	28.6493	28.9820			28.0371
	TARE:	29.2156	27.2322	29.4065	27.0353	27.6446	27.8697			27.0352
	Wt. @ 106:	30.1259	28.0367	30.3175	27.9106	28.4253	28.7766			27.8455
	COAL & CAP: (2)	28.7383	28.1725	28.0363	27.4767	26.8981	27.1393			27.9611
	TARE:	27.7350	27.2036	26.9579	26.4349	25.8624	26.0006			26.9579
	Wt. @ 106:	28.5233	27.9563	27.8155	27.2541	26.6677	26.9294			27.7686
SULFUR	%SULFUR: (1)	0.325	0.316	0.342	0.230	0.291	0.299			0.349
	%SULFUR: (2)	0.325	0.309	0.349	0.230	0.287	0.301			0.347
BTU	BTU/LB (1)	9355	9379	9619	9484	9364	9803			9690
	BTU/LB (2)	9359	9371	9622	9486	9373	9810			9685
ANALYSIS SUMMARY:		8/1/1998	8/2/1998	8/3/1998	8/4/1998	8/5/1998	8/6/1998	8/7/1998	8/8/1998	8/9/1998
% ADL		10.98	11.39	9.71	10.71	9.81	10.96			11.59
	%LAB MOIST.(1)	21.44	22.32	20.39	21.36	22.30	18.47			19.12
	%LAB MOIST.(2)	21.43	22.31	20.47	21.37	22.25	18.43			19.19
% LAB MOISTURE		21.43	22.32	20.43	21.37	22.27	18.45			19.16
DRY FACTOR		0.7857	0.7768	0.7957	0.7863	0.7773	0.8155			0.8084
AR FACTOR		0.6994	0.6883	0.7184	0.7021	0.7010	0.7261			0.7147
% TOTAL MOISTURE		30.06	31.17	28.16	29.79	29.90	27.39			28.53
DRY % SULFUR		0.414	0.402	0.434	0.292	0.372	0.368			0.430
AR % SULFUR		0.29	0.28	0.31	0.21	0.26	0.27			0.31
DRY BTU/LB		11910	12069	12091	12062	12053	12025			11983
AS RECEIVED BTU/LB		8330	8307	8687	8469	8449	8731			8565
AR LBS. SO2/MBTU		0.69	0.67	0.72	0.48	0.62	0.61			0.72
QA/QC SUMMARY:										
ADL to TM (35% - 45%)		36.5%	36.6%	34.5%	36.0%	32.8%	40.0%			40.6%
SAMPLE PRECISION:										
% TOT. MOIST. (WL=.106 CL=.30)		0.008	0.008	0.078	0.003	0.045	0.029			0.057
% DRY ASH (WL=.106 CL=.30)		0.004	0.004	0.039	0.001	0.022	0.015			0.029
% AS REC. SULFUR		0.000	0.006	0.006	0.000	0.004	0.002			0.002
% DRY SULFUR (WL=.18 CL=.05)		0.000	0.009	0.009	0.000	0.005	0.002			0.002
% AS REC. BTU		4	7	3	2	8	6			4
% DRY BTU (WL=18 CL=50)		5	10	4	3	12	9			6

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IS08810	IS08811	IS08812	IS08813	IS08814	IS08815	IS08816	IS08817	IS08818	IS08819	IS08820	IS08821	IS08822
33	22	21	18	24	24	22	15	14	16	35	35	34
17-Aug	17-Aug	17-Aug	18-Aug	18-Aug	18-Aug	18-Aug	24-Aug	24-Aug	24-Aug	26-Aug	26-Aug	26-Aug
18-Aug	18-Aug	18-Aug	19-Aug	19-Aug	19-Aug	19-Aug	25-Aug	25-Aug	25-Aug	27-Aug	27-Aug	27-Aug
TJ	TJ	TJ	TJ	TJ	TJ	TJ	TJ	TJ	TJ	TJ	TJ	TJ
1691.2	1652.7	1724.0	1646.4	1753.7	1779.2	1650.1	1677.5	1648.8	1671.4	1643.8	1665.7	1686.6
636.5	636.3	641.0	635.9	637.1	636.4	636.4	631.0	639.5	631.1	635.7	637.0	636.3
1568.2	1551.9	1630.3	1545.0	1642.6	1674.1	1560.1	1578.6	1553.8	1570.1	1526.3	1544.8	1572.4
26.8823	27.4801	28.6552	27.8603	28.0188	26.9055	26.8888	26.9648	28.0438	28.6693	30.2226	28.0938	28.4985
25.8621	26.4349	27.5264	26.7522	26.9560	25.9996	25.8604	26.0015	27.0359	27.6132	29.2152	27.1160	27.4881
26.6877	27.2679	28.4369	27.6589	27.8264	26.7283	26.6894	26.7753	27.8583	28.4623	30.0539	27.9294	28.3301
28.7796	30.4479	28.0535	28.7773	28.5879	28.0567	27.3068	28.0993	27.4606	28.6058	28.3264	28.9742	28.8856
27.6444	29.4066	27.0125	27.6426	27.5248	27.0105	26.3169	27.0124	26.3183	27.5263	27.2314	27.9198	27.7348
28.5636	30.2367	27.8527	28.5714	28.3950	27.8520	27.1147	27.8857	27.2508	28.3942	28.1428	28.7969	28.6940
0.299	0.199	0.214	0.238	0.239	0.235	0.252	0.245	0.249	0.280	0.234	0.222	0.236
0.296	0.192	0.209	0.234	0.237	0.239	0.253	0.249	0.245	0.282	0.238	0.230	0.238
9690	9698	9930	9954	9900	9824	9781	9718	9882	9703	10169	10123	10109
9694	9700	9939	9962	9907	9817	9785	9723	9886	9708	10165	10129	10107
#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######
11.66	9.92	8.65	10.03	9.95	9.20	8.88	9.45	9.41	9.74	11.66	11.75	10.87
19.07	20.30	19.34	18.18	18.10	19.56	19.39	19.67	18.40	19.60	16.75	16.81	16.67
19.03	20.28	19.29	18.15	18.15	19.57	19.41	19.65	18.37	19.60	16.77	16.82	16.65
19.05	20.29	19.31	18.16	18.12	19.56	19.40	19.66	18.39	19.60	16.76	16.81	16.66
0.8095	0.7971	0.8069	0.8184	0.8188	0.8044	0.8060	0.8034	0.8161	0.8040	0.8324	0.8319	0.8334
0.7151	0.7180	0.7371	0.7363	0.7373	0.7304	0.7345	0.7275	0.7393	0.7257	0.7354	0.7341	0.7428
28.49	28.20	26.29	26.37	26.27	26.96	26.55	27.25	26.07	27.43	26.46	26.59	25.72
0.368	0.245	0.262	0.288	0.291	0.295	0.313	0.307	0.303	0.350	0.284	0.272	0.284
0.26	0.18	0.19	0.21	0.21	0.22	0.23	0.22	0.22	0.25	0.21	0.20	0.21
11973	12168	12313	12168	12096	12209	12137	12100	12111	12072	12214	12173	12128
8562	8737	9075	8959	8918	8917	8914	8802	8954	8760	8982	8936	9009
0.61	0.40	0.43	0.47	0.48	0.48	0.52	0.51	0.50	0.58	0.46	0.45	0.47

40.9%	35.2%	32.9%	38.0%	37.9%	34.1%	33.4%	34.7%	36.1%	35.5%	44.1%	44.2%	42.3%

0.042	0.018	0.046	0.027	0.038	0.005	0.015	0.018	0.035	0.001	0.019	0.002	0.015
0.021	0.009	0.023	0.013	0.019	0.002	0.008	0.009	0.017	0.001	0.009	0.001	0.008
0.003	0.006	0.005	0.004	0.002	0.004	0.001	0.004	0.004	0.002	0.004	0.007	0.002
0.004	0.009	0.006	0.005	0.002	0.005	0.001	0.005	0.005	0.002	0.005	0.010	0.002
4	2	8	7	6	6	4	5	4	5	4	5	2
5	3	11	10	9	9	5	6	5	6	5	7	2

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IS AUG

									MONTHLY	
IS08823	IS08824	IS08825	IS08826	IS08827	IS08828	IS08829	IS08830	IS08831	MEAN	DEVIATION
25	30	27	29	34	32	21	34		26.86	
26-Aug	31-Aug	31-Aug	31-Aug	2-Sep	2-Sep	2-Sep	2-Sep			
27-Aug	1-Sep	1-Sep	1-Sep	3-Sep	3-Sep	3-Sep	3-Sep			
TJ	TJ	TJ	TJ	TJ	TJ	TJ	TJ			
1692.7	1630.1	1680.2	1630.9	1673.0	1765.4	1646.6	1655.8			
636.4	631.3	639.4	631.1	635.7	637.0	636.3	636.4			
1585.7	1535.0	1583.8	1532.2	1556.4	1655.5	1534.9	1545.2			
27.5336	28.1686	30.5278	28.3485	27.9882	28.4824	27.4566	29.6307			
26.5087	27.1169	29.4071	27.2329	26.9580	27.4881	26.4351	28.6615			
27.3431	27.9692	30.3068	28.1286	27.8204	28.3031	27.2769	29.4549			
28.1601	28.8128	30.3469	28.4060	28.7020	27.3454	27.3570	28.6644			
27.2034	27.7356	29.2167	27.2047	27.6123	26.3141	26.3280	27.5257			
27.9826	28.6086	30.1240	28.1689	28.5242	27.1594	27.1761	28.4576			
0.242	0.252	0.256	0.270	0.258	0.250	0.257	0.262			
0.247	0.256	0.255	0.274	0.255	0.247	0.258	0.260			
9943	9884	9785	9802	10123	10063	10009	9781		28	ANALYSIS
9951	9880	9793	9797	10120	10068	10013	9783		MONTHLY	
#######	#######	#######	#######	#######	#######	#######	#######	#######	MEAN	DEVIATION
10.13	9.52	9.26	9.87	11.24	9.74	11.06	10.85		10.29	
18.59	18.96	19.72	19.71	16.29	18.03	17.59	18.14		19.08	
18.55	18.96	19.72	19.74	16.32	18.04	17.58	18.16		19.08	
18.57	18.96	19.72	19.72	16.30	18.03	17.59	18.15		19.08	
0.8143	0.8104	0.8028	0.8028	0.8370	0.8197	0.8241	0.8185		0.8092	
0.7318	0.7333	0.7284	0.7235	0.7429	0.7398	0.7330	0.7297		0.7259	
26.82	26.67	27.16	27.65	25.71	26.02	26.70	27.03		27.41	
0.300	0.313	0.318	0.339	0.306	0.303	0.312	0.319		0.32	
0.22	0.23	0.23	0.25	0.23	0.22	0.23	0.23		0.24	
12215	12194	12194	12207	12093	12280	12147	11951		12119	
8939	8941	8882	8832	8984	9085	8904	8721		8798	
0.49	0.51	0.52	0.56	0.51	0.49	0.51	0.53		0.54	
37.8%	35.7%	34.1%	35.7%	43.7%	37.4%	41.4%	40.1%		37.6%	
0.030	0.003	0.002	0.023	0.025	0.002	0.010	0.020		0.022	
0.015	0.001	0.001	0.012	0.013	0.001	0.005	0.010		0.011	
0.004	0.004	0.001	0.004	0.003	0.003	0.001	0.002		0.003	
0.006	0.005	0.001	0.005	0.004	0.004	0.001	0.002		0.005	
7	4	7	5	3	5	4	2		4.62	
10	5	10	6	4	6	5	2		6.37	

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