ADEQ
ARKANSAS
Department of Environmental Quality

November 5, 2008

Kris Gaus, Senior Environmental Specialist
American Electric Power Service Corp. - Turk Power Plant
PO Box 660164
Dallas, TX 75266-0164

Dear Mr. Gaus:

The enclosed Permit No. 2123-AOP-R0 is issued pursuant to the Arkansas Operating Permit Program, Regulation # 26.

After considering the facts and requirements of A.C.A. §8-4-101 et seq., and implementing regulations, I have determined that Permit No. 2123-AOP-R0 for the construction, operation and maintenance of an air pollution control system for American Electric Power Service Corp. - Turk Power Plant to be issued and effective on the date specified in the permit, unless a Commission review has been properly requested under §2.1.14 of Regulation No. 8, Arkansas Department of Pollution Control & Ecology Commission's Administrative Procedures, within thirty (30) days after service of this decision.

All persons submitting written comments during this thirty (30) day period, and all other persons entitled to do so, may request an adjudicatory hearing and Commission review on whether the decision of the Director should be reversed or modified. Such a request shall be in the form and manner required by §2.1.14 of Regulation No. 8.

Sincerely,

Mike Bates

Mike Bates
Chief, Air Division

ADEQ
OPERATING
AIR PERMIT

Pursuant to the Regulations of the Arkansas Operating Air Permit Program, Regulation 26:

Permit No. : 2123-AOP-R0
IS ISSUED TO:

John W. Turk, Jr. Power Plant
Hwy. 335, 2 Miles North of Fulton
Fulton, AR 71838
Hempstead County
AFIN: 29-00506

THIS PERMIT AUTHORIZES THE ABOVE REFERENCED PERMITTEE TO INSTALL, OPERATE, AND MAINTAIN THE EQUIPMENT AND EMISSION UNITS DESCRIBED IN THE PERMIT APPLICATION AND ON THE FOLLOWING PAGES. THIS PERMIT IS VALID BETWEEN:

November 5, 2008 AND November 4, 2013

THE PERMITTEE IS SUBJECT TO ALL LIMITS AND CONDITIONS CONTAINED HEREIN.

Signed:

Mike Bates
Chief, Air Division

November 5, 2008
Date

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List of Acronyms and Abbreviations

A.C.A.	Arkansas Code Annotated
ACI	Activated Carbon Injection
acf	Actual Cubic Feet
AFIN	ADEQ Facility Identification Number
CAMR	Clean Air Mercury Rule
CEM	Continuous Emission Monitor
CFR	Code of Federal Regulations
CO	Carbon Monoxide
HAP	Hazardous Air Pollutant
Hg	Mercury
lb/hr	Pound Per Hour
lb/MMBtu	Pound per million British Thermal Unit
lb/TBtu	Pound per Trillion British Thermal Units
MVAC	Motor Vehicle Air Conditioner
No.	Number
NO_x	Nitrogen Oxide
NSPS	New Source Performance Standard
Pb	Lead
PC	Pulverized Coal
PM	Particulate Matter
PM_{10}	Particulate Matter Smaller Than Ten Microns
ppm	Parts Per Million
PRB	Powder River Basin
SN	Source Number
SNAP	Significant New Alternatives Program (SNAP)
SO_2	Sulfur Dioxide
SSM	Startup, Shutdown, and Malfunction Plan
Tpy	Tons Per Year
UTM	Universal Transverse Mercator
VOC	Volatile Organic Compound

SECTION I: FACILITY INFORMATION

PERMITTEE:	John W. Turk, Jr. Power Plant
AFIN:	29-00506
PERMIT NUMBER:	2123-AOP-R0
FACILITY ADDRESS:	Hwy. 335, 2 Miles North of Fulton Fulton, AR 71838
MAILING ADDRESS:	P.O. Box 660164 Dallas, Texas 75266-0164
COUNTY:	Hempstead
CONTACT POSITION:	Kris Gaus
TELEPHONE NUMBER:	(214) 777-1113
REVIEWING ENGINEER:	Thomas Rheaume, PE
UTM North South (Y):	Zone 15: 424.735
UTM East West (X):	Zone 15: 3,723.20

SECTION II: INTRODUCTION

Summary of Permit Activity

Southwest Electric Power Company (SWEPCO), a unit of American Electric Power (AEP), proposes to construct a new coal-fired electric power generating facility near Fulton, Arkansas, in Hempstead County. This facility will be named the John W. Turk, Jr. Power Plant. The main steam generating unit will consist of one ultra-supercritical pulverized coal boiler powering a single steam turbine designed for base load operation with a nominal net power output of 600 megawatts. This boiler will burn sub-bituminous coal and natural gas. The major permitted emission rates for this facility are 801.56 tpy PM, 732.26 tpy PM_{10}, 2102.69 tpy SO_2, 23.08 tpy VOC, 3952.0 tpy CO, 1336.6 tpy NO_x, and 110.38 tpy H_2SO_4.

Process Description

Coal Handling

Coal is unloaded by an enclosed rotary car dumper through two underground hoppers onto belt feeders BF-1/2. The coal unloading drops are designated TP-1. Surfactant sprays are used at the rotary car dumper to minimize dusting. The underground belt feeders BF-1/2 drop the coal onto coal conveyor C-1. This drop point is designated TP-2. Residual sprays are used at TP-2 to further minimize dusting. Emissions from TP-1 and TP-2 are exhausted through the coal dumper tunnel exhaust fan (SN-EP-1).

Coal conveyor C-1 carries the coal from underground and drops it in the enclosed transfer house onto either conveyor C-2 or C-5A. Conveyor C-2 carries the coal to the enclosed head house above lowering well 1 at active coal pile A or to coal conveyor C-3, which then carries it to lowering well 2 at active coal pile B. Residual sprays are used at the drop from conveyor C-1. Emissions are generated from the open drops from conveyor C-1 to lowering well 1 (SN-EP-3), from conveyor C-1 to conveyor C-3 (SN-EP-2), and from conveyor C-3 to lowering well 2 (SN-EP-4).

Emissions are generated from wind erosion at active coal pile A (SN-F-1), active coal pile B (SN-F-2), and the inactive coal pile (SN-F-4), and dozing activities among the piles (SN-F-3).

Coal is reclaimed from the active coal piles in the underground reclaim tunnel. The underground reclaim drops include two rotary plow drops onto conveyor C-4 designated TP-3 and TP-5, a drop on the conveyor C-4 line designated TP-7. Surfactant sprays are used at the rotary plow drops and fog is used at the conveyor line drops. Emissions from the underground coal reclaim tunnel drops TP-3, TP-4, TP-5, TP-6, TP-7, and TP-8 are exhausted through two coal reclaim tunnel exhaust fans (SN-EP-5/6).

Conveyor C-4 carries the coal from the underground reclaim tunnel to the enclosed transfer house where it drops onto conveyor C-5A. Conveyor C-5A carries the coal to the crusher house surge bins. The enclosed (in the crusher house) drops to the surge bins are designated TP-9 and

TP-10. The surge bins are each equipped with a bin vent filter (SN-TP-11 and SN-TP-12). From the bottom of the surge bins, coal is unloaded by belt feeders BF-3/4, which drop to coal into crushers. These drops are designated TP-13 and TP-14. After being crushed, the coal is dropped onto conveyor C-6A. These drops are designated TP-15 and TP-16. Fog is used at the crusher drops. Emissions generated from drops TP-9, TP-10, TP-13, TP-14, TP-15, and TP-16 within the coal crusher house are exhausted through two coal crusher house exhaust fans (SN-EP-7/8).

A reclaim conveyor pulls some coal from conveyor C-6A to the sample house. Emissions generated at the sample house are exhausted through the sample house exhaust fan (SN-EP-9).

Conveyor C-6A carries the coal from the crusher house to the power plant and drops it on tripper conveyor C-7A. These drops are designated TP-18 and TP-19. Fog is used at the conveyor-to-tripper conveyor drops. The tripper conveyors drop the coal into the in-plant storage silos. These drops are designated TP-20 and TP-21. Emissions generated from drops TP-18, TP-19, TP-20, and TP-21 within the power plant are exhausted through a wet fan dust collector (SN-EP-10).

Power Plant

An ultra-supercritical pulverized coal (PC) boiler (SN-01) produces steam to drive a condensing steam turbine to generate electricity. The PC boiler burns sub-bituminous coal as the main fuel and uses natural gas for startup and flame stabilization. A natural gas-fired auxiliary boiler (SN-02) is also used during startup of the PC boiler.

During normal operation, emissions from the PC boiler are controlled using low-NO_X burners (LNB) with over-fire air (OFA), selective catalytic reduction (SCR), dry flue gas desulfurization (DFGD)/spray dryer absorber (SDA), and pulse jet fabric filtration (i.e., PJFF baghouse) and activated carbon injection (ACI).

Cooling water used in the steam turbine condenser is provided by a mechanical draft cooling tower (SN-CT-1). Plant makeup water is treated in the onsite water treatment facility.

Anhydrous ammonia for use in the SCR system is stored in tanks equipped with pressure vent valves set to minimize standing losses. The ammonia is vaporized and transported from the storage tanks to the injection location.

Lime Handling

Lime for use in the SDA is delivered by rail, unloaded with a vacuum pneumatic system, and pneumatically conveyed to a lime storage silo. The exhaust point for this system is the two Lime Vacuum Conveyor (Railcar Unloading) Exhausters (SN-EP-15 and SN-EP-16). The lime silo is equipped with a bin vent filter (SN-EP-17). From the storage silo, the lime is pneumatically conveyed to the lime day bin(s) in the lime-slurry preparation area. The lime day bin(s) are equipped with bin vent filters (SN-EP-18 and SN-EP-19). Lime from the day bin(s) is formed into a slurry in a lime slaking system. The slurry is then pumped to the SDA.

Fly Ash and FGD Waste Handling

Fly ash and FGD waste removed from the flue gas is pneumatically conveyed to storage silos. The storage silos are equipped with bin vent filters (SN-EP-21 and SN-EP-22). Each vacuum conveyance system has exhausters (SN-EP-23 and SN-EP-24). From the storage silos, the fly ash/FGD waste is mixed with water and then drop loaded into open top dump trucks (SN-TP-22). The dump trucks unload the fly ash/FGD waste to an onsite landfill (SN-TP-23). Emission may be generated by wind erosion of the landfill (SN-F-6), dozing of the fly ash/FGD waste and overburden (SN-F-5), and by the haul roads (SN-RD-1).

Bottom ash, which includes furnace ash from the boiler, pyrites from the mills, and economizer ash, is collected in a submerged, water-filled trough and then conveyed to a storage bunker. From the bunker, the bottom ash is loaded into trucks and hauled to disposal. Any emissions from the handling of bottom ash are accounted for above.

Emergency Equipment

A diesel-fired emergency generator (SN-03) is used to supply power during outages and a small diesel-fired engine (SN-04) is used to pump water needed for fire suppression. Diesel fuel is stored in tanks (insignificant activity).

Prevention of Significant Deterioration

This facility is considered to be a new major source under 40 CFR 52.21, Prevention of Significant Deterioration (PSD) regulations. This SWEPCO facility will have significant emissions of PM/PM_{10}, SO_2, VOC, CO, NO_x, lead (Pb) and sulfuric acid mist (H_2SO_4) and is required to undergo PSD review for these pollutants.

Class II Ambient Air Impact Analysis

Since the total facility-wide emissions exceed the PSD significant emission rates for NOx, CO, PM_{10}, Lead and SO_2, an air quality analysis is required to demonstrate that these emissions do not cause or contribute to a violation of the National Ambient Air Quality Standards (NAAQS) or exceed a PSD increment.

For PSD permits, a full ambient air impact analysis is required for each pollutant from which the net emission increase will result in an ambient impact over the predetermined level. This level is known as the "significant impact level" (SIL) and the analysis of emissions with respect to these levels is known as the "significance analysis". The following table shows the results of the significance analysis. The significance analysis shows a full impact analysis was required for

PM_{10}. A full impact analysis was conducted for lead since there is no Lead SIL, a full impact analysis is always needed.

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)	Significant impact Level ($\mu g/m^3$)
CO	1-hour	23.7	2,000
	8-hour	12.9	500
PM_{10}	24-hour	19.68	5
	Annual	2.97	1.0
NO_x	Annual	0.91	1.0
SO_2	3-hour	10.38	25
	24-hour	4.22	5
	Annual	0.49	1.0

Lead NAAQS Analysis

Pollutant	Averaging Period	Highest Modeled Concentration with Background ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	% of NAAQS
Pb	Calendar Quarter	0.35044	1.50	23.4

PM_{10} full impact analysis

Pollutant	Averaging Period	Highest Modeled Concentration with Background ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	% of NAAQS
PM_{10}	24-hour	62.8	150	41.87
	Annual	25.05	50	50.02

Arkansas Regulations require further analysis if a facility consumes more than 50% of any available long term increment and 80% of any short term increment. The following table shows the results of the PSD Class II increment modeling for PM_{10}. As demonstrated, no further analysis is needed.

Averaging Period	Year of Maximum Impact	Modeled Concentration (μg/m^3)	PSD Increment (μg/m^3)	% Consumed
24-Hour	2004	13.92	30	46.4%
Annual	2001	3.22	17	18.9%*

* Since the modeling results showed the facility and surrounding sources consumed no more than 50% of the long term increment was consumed, it is mathematically impossible for the facility to have consumed more than 50% of the available long term increment.

Class I Analysis

The Clean Air Act Amendments of 1977 included provisions for the protection of visibility in designated Class I areas. These requirements are detailed in USEPA's PSD program in 40 CFR Parts 51 and 52. Federal Land Managers (FLM) have the responsibility of evaluating the effects of air pollution in such designated areas. This includes evaluating potential impacts due to visibility degradation, ambient pollutant concentrations, and increment consumption. The FLM typically follow the recommendations of the "Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long Range Transport Impacts" (EPA 454/R-98-019) and the "Federal Land Managers' Air Quality Related Values Workgroup (FLAG) Phase 1 Report" (December 2000) for air quality dispersion modeling analyses.

If a proposed project is predicted to have maximum modeled air quality concentrations in the Class I areas less than the significant impact levels (SILs), then it is assumed that the project will not have a significant impact and no further air quality analyses are necessary. The CALMET/CALPUFF models were run to evaluate the impact of the proposed sources on both the Caney Creek and Upper Buffalo Class I areas. The results are presented below.

Class I Area	Year	Maximum Modeled Concentrations (μg/m^3)					
		SO_2			PM_{10}		NO_x
		3-hour	24-hour	Annual	24-hour	Annual	Annual
Caney Creek	2001	2.35	0.558	0.0298	0.353	0.0196	0.0238
	2002	2.29	0.439	0.0226	0.301	0.0143	0.0182
	2003	2.34	0.570	0.0279	0.305	0.0180	0.0239
Upper Buffalo	2001	0.389	0.159	0.00645	0.105	0.00632	0.00343
	2002	0.669	0.165	0.00801	0.137	0.00697	0.00539
	2003	0.518	0.169	0.00633	0.119	0.00586	0.00389
Class I Area SIL (μg/m^3)		1.0	0.2	0.1	0.3	0.2	0.1
Class I Area Increment (μg/m^3)		25	5	2	8	4	2.5

Multi-Source Increment Modeling Analysis

Because the SO_2 and PM_{10} concentrations exceeded the SILs listed above, multi-source modeling was required for SO_2 and PM_{10} short-term averaging periods.

In the case of total SO_2 impacts, sometimes the predicted total impacts exceeded the allowable increment. The following tables summarize the results.

Class I Area	Year	Highest-First-High Modeled SO_2 Concentrations (µg/m^3)					
		3-Hour Average			24-Hour Average		
		Inventory	Project	Total	Inventory	Project	Total
Caney Creek	2001	34.48	0.00	34.48	9.40	0.03	9.44
	2002	44.00	0.00	44.00	5.87	0.00	5.87
	2003	39.53	0.00	39.53	8.24	0.00	8.24
Upper Buffalo	2001	n/a	< SIL	n/a	n/a	< SIL	n/a
	2002	n/a	< SIL	n/a	n/a	< SIL	n/a
	2003	n/a	< SIL	n/a	n/a	< SIL	n/a
Class I Area SIL (µg/m^3)		1.0	1.0	1.0	0.2	0.2	0.2
Class I Area Increment (µg/m^3)		25	25	25	5	5	5

To comply with the PSD increments, the proposed sources must not make a significant contribution to any second, third, fourth, etc. highest values at all receptors with a predicted exceedance of the PSD Increment in the Class I areas.

Since the proposed Turk facility's impacts are below the significant impact level during any of the predicted exceedences, the facility does not contribute significantly to any of these predicted total concentrations that may be above allowable Class I increments (due to other increment consuming sources). These impacts are summarized below.

Averaging Time	Increment (µg/m^3)	Highest Turk Impact when Total Impacts > Increment (µg/m^3)	Significant Impact Level (µg/m^3)
3 Hour	25	0.0	1.0
24 Hour	5	0.19*	0.2

* Based on the 2nd high at each receptor

Similar analyses were performed to determine the potential PM_{10} impacts at Caney Creek from all PSD increment consuming sources identified. The results of this analysis are summarized in the following table. These results indicate that all predicted highest-2nd-high concentrations are well below the allowable PSD increment concentrations.

Class I Area	Year	Modeled Concentrations PM_{10} ($\mu g/m^3$)			
		24-Hour Highest-First-High		24-Hour Highest-Second-High	
		Total Concentration	Project Contribution	Total Concentration	Project Contribution
Caney Creek	2001	0.42	0.33	0.36	0.28
	2002	0.41	0.03	0.40	0.00
	2003	0.51	0.00	0.44	0.16
Class I Area SIL ($\mu g/m^3$)		0.3	0.3	0.3	0.3
Class I Area Increment ($\mu g/m^3$)		8	8	8	8

Class I Visibility

Modeling was performed to determine the how the emissions from the proposed sources will impact the visibility in the Caney Creek and Upper Buffalo Class I area. Using alternative CALPOST methods and AERMOD dispersion, SWEPCO was able to show that no events in any of the three years modeled at Caney Creek have a predicted maximum change in light extinction greater than 10%. Further, the Method 6 AERMOD dispersion results for Caney Creek based on the annual average extinction background visual range and highest-eighth-high value are below 5% for all three years modeled. The results at the Upper Buffalo Class I area also indicate that the predicted change in light extinction with the turbulence based dispersion and the alternative Method 6 are minimal. Considering the results based on the application of both the latest alternative methods for calculation of light extinction and the less conservative turbulence-based dispersion option, it is concluded that the John W. Turk, Jr., project will not have a significant impact on visibility at the Caney Creek or Upper Buffalo Class I areas.

The USDA/Forest Service reviewed the visibility modeling and predicted impacts. Based on the results of Method 2 analysis alone, the Federal Land Manager (FLM) required mitigation of the predicted visibility impacts. SWEPCO proposed and the FLM accepted voluntary reductions of SO_2 emissions at the SWEPCO Welsh plant in Texas to offset any visibility impacts. The offsets/emission reductions were based on modeling the visibility impacts of the Welsh plant on the Caney Creek Class I area. A SO_2 emission rate was established that mitigated an equivalent number of days that the Method 2 analysis for the Turk plant predicted impacts over 5%. These emission rates and conditions are contained in the Plantwide Conditions of this permit.

BACT Analysis Summary

For this BACT analysis, potential control technologies (and resulting emission limits) were identified using the most recent version (dated October 20, 2005) of the Coal-fired Utility Database and a query of the RBLC database (for coal-fired external combustion units for which

PSD permits have been issued since 1990) as well as SWEPCO's experience in building and operating coal plants. For all pollutants except CO and VOC, the RBLC database did not identify any relevant units beyond those already contained in the Coal-fired Utility Database. For approximately 50 of the relevant units identified in these databases, the information provided was compared against (and revised, where necessary) available permitting information to further investigate and evaluate possible control technologies and the performance levels of those technologies.

BACT Evaluation for Main Boiler

The following technologies were considered for the main boiler (SN-01).

Pollutant	Coal-Fired Boiler Control Technologies
$PM/PM_{10}/Pb$	Baghouse Electrostatic Precipitator (ESP) Venturi Scrubber
SO_2	Wet Flue Gas Desulfurization (WFGD) Dry Flue Gas Desulfurization (DFGD)
VOC	Catalytic Oxidation Proper Boiler Design and Operation
CO	Catalytic Oxidation Proper Boiler Design and Operation
NO_x	Selective Catalytic Reduction (SCR) Selective Non-Catalytic Reduction (SNCR) Low NO_x Burners (LNB) / Over-Fire Air (OFA) Flue Gas Recirculation (FGR)
H_2SO_4 Mist	DFGD with a Baghouse WFGD with a Wet ESP Sorbent Injection

The second step in the BACT analysis is to eliminate any technically infeasible control technologies. Each control technology for each pollutant is considered, and those that are clearly technically infeasible are eliminated.

The only technically infeasible options are flue gas recirculation for NO_x control and catalytic oxidation for CO and VOC control.

Flue Gas Recirculation

FGR is primarily used to reduce thermal NO_x formation. Emissions due to fuel-bound NO_x, which are significant for coal-fired boilers, are not meaningfully affected by FGR. Moreover, the reduction in thermal NO_x is accomplished by recirculating the flue gas into the windbox. However, for coal-fired boilers operating at peak boiler capacity the recirculated flue gas is needed to control temperature in the secondary superheater and reheater and is commonly readmitted above the windbox. This method of FGR does not reduce NO_x emissions. Therefore, FGR is not technically feasible to control NO_x emissions from PC boilers.

Catalytic Oxidation

Catalytic oxidation is not technically feasible for use with coal-fired boilers because the catalyst consists of several precious metals that are easily contaminated by sulfur compounds in the flue gas and are eroded and destroyed by the high levels of fly ash in the flue gas. No currently available catalyst material can operate in the harsh conditions resulting from coal combustion. In addition to the technical considerations, the oxidation catalyst would create adverse environmental impacts (by oxidizing more SO_3 and therefore creating more H_2SO_4 mist emissions) and adverse energy impacts (due to the increase in pressure drop across the system). Furthermore, SWEPCO is not aware of any installations worldwide of catalyst on a coal-fired unit. As catalytic oxidation is not technically feasible, this option is removed from BACT consideration.

The control technologies are then ranked in order of effectiveness and then the control technologies are evaluated on the basis of economic, energy, and environmental considerations.

PM/PM_{10}/Pb Controls

A baghouse has the highest control efficiency of any of the particulate control options, and therefore, according to the "top-down" approach, is considered first. A baghouse is chosen as BACT for PM and Pb control. In accordance with EPA guidance, the remaining particulate control devices (i.e., ESP and venturi scrubber) are not considered further since the highest efficiency (99.9%) control device is selected as BACT.

SO_2 *Controls*

Two common SO_2 control techniques exist for coal-fired boilers: WFGD and DFGD. In a FGD system, an alkaline reagent (usually lime or limestone) is injected into the flue gas, where it reacts with and collects the SO_2. WFGD has the highest control efficiency of the two SO_2 control options, and therefore, according to the "top-down" approach, is considered first. In a WFGD system, the alkaline reagent is in the form of a slurry. The flue gas is routed to a spray tower where it is contacted by the slurry. A mist eliminator removes moisture from the flue gas as it exits the WFGD system. The control cost for a WFGD is approximately $1,832.00/ton SO_2 removed. There are several challenging environmental impacts associated with WFGD systems. The large volume of used wet caustic mixture produced by WFGD must be treated and disposed. The WFGD waste product can be recycled, but is most often sent to a landfill. Also, the moisture added to the flue gas by a WFGD system creates a visible vapor plume, prevents the use of opacity monitors downstream of the WFGD, and results in increased nearby ground level impacts due to the cooler, less buoyant plume.

Make-up water consumption to the FGD system would increase by approximately 900% when going from the proposed dry system to a wet system. This is because the Dry FGD system at the Turk Plant will utilize process wastewater from the cooling tower and other plant processes for approximately 80% of the total water requirement, as compared to 100% treated make-up water required for a Wet FGD. Much of the wastewater produced in the Wet FGD cannot be reused continuously in the process and must be purged from the system and sent to a wastewater treatment system to remove suspended solids, dissolved mercury, and for pH adjustment before it is sent to an outfall. The wastewater treatment system is estimated to cost \$30 – \$35 Million based on similar systems being installed on the AEP fleet, and will produce up to approximately 4.25 tons per hour (TPH) of additional solid waste material that will need to be disposed in the landfill. Dry FGD systems produce essentially no additional wastewater discharge to local streams/rivers.

SO_3 and sulfuric acid mist emissions are also expected to be 6.5 to 40% lower with the use of the Dry FGD system due to the use of lime as the process reagent. Lime inherently absorbs acid mist and the Turk Plant sulfuric acid emissions are expected to be approximately 30 lb/hr without additional means of SO_3 / H_2SO_4 mitigation. The wet FGD system would likely require a Trona or other sorbent injection system, estimated to cost approximately \$10 Million, to reduce SO_3 / H_2SO_4 emissions to levels matching that of the dry FGD system. A Trona injection system is expected to add 0.5 – 1.0 TPH of additional solid waste to the fly ash that will need to be disposed in the landfill.

Additional solid waste streams from the wastewater treatment system and the Trona Injection system could add up to 45,000 TPY of additional solid waste to the landfill. This additional waste (depending on its density) could require up to 17 acres of additional landfill at a cost of \$4.25 Million.

Auxiliary power demand for the proposed Dry FGD system at the Turk Plant is approximately 0.6% of net unit output, or 3.7 MW. Typical auxiliary power demand for a Wet FGD system on a similar sized unit burning sub-bituminous coal is 1.0 to 1.5% of net unit output. Therefore, a Wet FGD system at the Turk Plant would likely consume 6 to 9 MW of auxiliary power. To maintain the nominal net unit output, the Turk Plant would have to be permitted to burn approximately 1.5 to 3.4 tons/hr of additional PRB coal to make up for the additional auxiliary power demand imposed by the Wet FGD. This near 0.5 to 1.0% increase in total fuel consumption would have a directly proportional impact on unit emissions. While the SO_2 emissions would be offset by the increase in efficiency of the Wet FGD system, increases in NO_x, PM, CO_2, etc. of 0.5 to 1.0% would not be offset.

The additional auxiliary power demand from the wet FGD system results in lost unit capacity that could range from 18,000 – 40,000 MWH per year. Unless Turk is permitted to burn additional fuel, the lost capacity will likely be recovered by means of purchasing the power on the open market. Assuming \$30/MWH, the resulting energy replacement cost would range from \$540,000 - \$1,200,000 annually.

Total PM has the potential to be higher in wet FGD systems due to gypsum fines and acid mist in the flue gas. Wet FGD systems can also contribute greater fugitive PM emissions due to the need for large limestone storage piles and handling systems.

While no quantitative data exists to support a claim, the proposed Dry FGD system at the Turk Plant appears better suited for mercury (Hg) capture. The Turk Plant's Dry FGD system will be equipped with a Powdered Activated Carbon (PAC) injection system immediately upstream of the SDA vessel, which provides excellent flue gas mixing and residence time for the carbon to absorb the oxidized Hg in the flue gas. The baghouse ultimately captures the Hg before it is released to the atmosphere. While an activated carbon injection (ACI) system would likely be used in conjunction with a wet FGD system, the absence of an SDA vessel to provide mixing could result in less efficient mercury capture.

The most significant difference between Dry Flue Gas Desulfurization (FGD) technology and Wet FGD technology concerns the up-front capital cost, which is approximately $102 Million versus $233 Million respectively for a 600 MW 100% PRB application like the Turk Plant. Looking at these capital cost estimates on an annual $/ton SO_2 removed basis (assuming a 15% capital carrying charge), the dry FGD system is roughly 45% of the cost of the wet FGD system ($647/ton removed for Dry FGD versus $1422/ton removed for Wet FGD). However, the capital cost differential between the two technologies (approx $131 Million) for the additional 920 tons of SO_2 removed annually by the wet system over the dry system, yields a cost of approximately $21,000/ton removed for the additional SO_2 capture. A major driver in the capital cost increase to go to a wet scrubber lies in the materials of construction (e.g. major equipment, piping, ductwork, stack liner, etc. must be constructed of alloy or fiberglass materials), and while this adds to up front capital cost, it also means higher operations and maintenance costs throughout the life of the plant.

Based on the energy and environmental factors discussed above, WFGD is eliminated from consideration as BACT.

CO and VOC Control

For a coal-fired boiler, emissions of CO and VOC are the result of incomplete combustion and thus represent uncaptured energy. Therefore, units have an incentive from a production standpoint to reduce CO and VOC emissions through proper boiler design and operation. Operating with higher flame temperatures and longer furnace residence times can reduce CO and VOC emissions. Unfortunately, reducing CO and VOC emissions can result in an increase of NO_x emissions from the boiler. No post combustion CO and VOC controls have been demonstrated for coal-fired facilities.

Proper design and operation of the boiler is the only effective control option. Emissions of CO and VOC have traditionally been maintained very low by design. Therefore, proper boiler design and operation is selected as BACT for CO and VOC.

NO_x Control

SCR has the highest control efficiency of any of the NO_x control options, and therefore, according to the "top-down" approach, is considered first. Based on the review of EPA's control technology databases, all modern PC boilers use a combination of SCR and LNB to control NO_x. SWEPCO's proposed boiler will be equipped with SCR and LNB (with OFA) as BACT for NO_x control. In accordance with EPA guidance, the remaining NO_x control devices are not considered further in the BACT analysis since the highest efficiency control device is selected as BACT.

H_2SO_4 Mist Control

Until recently, H_2SO_4 mist received minimal review in permits. However, it has received increased attention for boilers equipped with SCR since the SCR oxidizes some portion of the SO_2 to generate additional SO_3, which reacts with water in the exhaust stream to produce H_2SO_4.

The two primary techniques for H_2SO_4 mist control are WFGD with a Wet ESP and DFGD with a baghouse. Both control techniques involve scrubbing with an alkali followed by particulate control. DFGD and a baghouse have been selected as BACT for the proposed boiler for SO_2 and PM/PM_{10} control, respectively. Therefore, a WFGD and Wet ESP system is not feasible for H_2SO_4 mist control for the proposed boiler. Moreover, DFGD followed by a baghouse provides for the most H_2SO_4 mist removal of the control options. Therefore, a DFGD system with a baghouse is chosen as BACT for H_2SO_4 mist control.

Additional sorbent injection is not practical for use on the proposed boiler since it will be equipped with a DFGD system (as a result of the SO_2 BACT analysis). H_2SO_4 mist in the flue gas will be captured by the alkaline scrubbing agent in the DFGD system. Additional sorbent injection would only serve to add more alkali to the flue gas stream. SWEPCO will be able to meet BACT level limits for H_2SO_4 mist emissions by, among other things, controlling the amount of scrubbing agent used in the DFGD system. Therefore, additional sorbent injection is eliminated from further consideration in this BACT analysis.

SWEPCO proposed a limit of 0.10 lbs/MMBtu and later revised it to 0.08 lbs/MMBtu during the draft period. ADEQ added an additional limit of 0.065 lbs/MMBtu while combusting coal containing less than 0.45% sulfur after the draft, in response to comments, and based on the latest information for similar permits.

BACT Selection

The following table summarizes the BACT and associated emissions limits chosen for the Main Boiler (SN-01) this facility. These BACT limits are consistent with those found at similar facilities.

Main Boiler (SN-01)				
Pollutant	*Control Technology Determination*	*BACT Limit*	*Averaging period*	*Compliance Method*

PM (filterable)	Baghouse	0.012 lb/MMBtu	3-hour	Method 5 or 17
PM_{10} (filterable)	Baghouse	0.012 lb/MMBtu	3-hour	Method 5 or 17
PM_{10} (total)	Baghouse	0.025 lb/MMBtu	3-hour	Methods 5 or 17 and 202
SO_2	Dry Flue Gas Desulfurization	0.08 lb/MMBtu While combusting coal with a sulfur content greater than 0.45% by weight	30-day rolling average	CEM
		0.065 lb/MMBtu While combusting coal with a sulfur content less than or equal to 0.45% by weight	30-day rolling average	CEM
		480 lbs/hr	24 hour rolling average	CEM
VOC	Proper Design/Operation	0.0036 lb/MMBtu[1]	3-hour	Method 25
CO	Proper Design/Operation	0.15 lb/MMBtu	30-day rolling	CEM
NO_x	SCR	0.067 lb/MMBtu for normal operations[2]	24-hour rolling average	CEM
		420 lbs/hr	24 hour rolling average	CEM
		0.05 lb/MMBtu	Annual average	CEM
Pb	Baghouse	2.6E-5 lb/MMBtu[3]	3-hour	Method 12 or 29
H_2SO_4 Mist	DFGD with Baghouse	0.0042 lb/MMBtu	3-hour	Method 8

[1] VOC rate based on 112(g) analysis will be set at 0.00078 lb/MMBtu
[2] Normal operation is defined as operation at or above 300 MW gross output from the Unit 1 generator
[3] Pb rate based on 112(g) analysis will be set at 1.6 E-05 lb/MMBtu

BACT Evaluation for Auxiliary Boiler

A BACT analysis was also performed for emissions from the auxiliary boiler (SN-02). An auxiliary boiler with a nominal heat input capacity of 555 MMBtu/hr will be constructed and operated on an as needed basis for start-up purposes. The auxiliary boiler will be fired with natural gas only and will be limited to an annual heat input of 277,500 MMBtu (equivalent to operating 500 hours per year at full capacity).

EPA's RBLC is used as the primary data source for existing limits for comparable boilers. The generally comparable source type is natural-gas fired boilers with heat input capacities greater than 400 MMBtu/hr. However, most of the boilers of this size listed in the RBLC are intended to operate continuously. Therefore, the most comparable source type is other similar-sized auxiliary boilers. The RBLC includes five (5) facilities with similar-sized part-time auxiliary boilers.

NO_x Control

While there is a range of potential control technologies available to control NOx, the only two technologies (besides good combustion practices / fuel specification) found for generally comparable sources in the RBLC are LNB and FGR. SWEPCO proposes a BACT limit of 0.11 lb/MMBtu for NO_x emissions from the auxiliary boiler. This limit is equivalent to the recently published NSPS Subpart Db limit and is comparable to the lowest limit presented in the RBLC. SWEPCO proposes to implement the limit on a 30-day rolling average basis (same as NSPS Subpart Db).

SO_2 *Control*

Based on the RBLC review, the sole control technology determined as BACT for generally comparable units is control of the inlet fuel sulfur. SWEPCO proposes an emission limit of 0.6 lb/MMscf (approximately equivalent to 0.0006 lb/MMBtu), based on AP-42 and typical pipeline natural gas sulfur content, as BACT for the auxiliary boiler. Per NSPS Subpart Da, which sets a limit of 0.15 lb/MMBtu, compliance with the emission limit will be achieved through the use of natural gas as the only fuel.

PM Control

Similar to SO_2, the sole control technology determined as BACT for PM in the RBLC for comparable units is combustion of clean burning fuels. SWEPCO proposes an emission limit of 7.6 lb/MMscf (approximately equivalent to 0.0076 lb/MMBtu), based on AP-42, as BACT for the auxiliary boiler. The applicable NSPS Subpart Da limit is 0.015 lb/MMBtu. Compliance with the emission limit will be achieved through the use of natural gas as the only fuel.

Pb Control

Per AP-42, lead is a trace compound in natural gas. As such, BACT for Pb is proposed as a work practice standard based on using only natural gas as fuel in the auxiliary boiler. No emission limit or testing is proposed for Pb from this source.

VOC/CO Control

While there is a range of potential control technologies available to control CO and VOC, there is only one technology found for generally comparable sources in the RBLC: good combustion practices. The Boiler MACT establishes a CO work practice standard of 400 ppmvd at 3 percent oxygen (30-day rolling average basis) and requires a CO CEMS. SWEPCO proposes the Boiler MACT work practice standard as BACT for CO. VOC BACT is proposed as 5.5 lb/MMscf (approximately equivalent to 0.0055 lb/MMBtu), based on AP-42.

The following table summarizes the BACT and associated emissions limits chosen for the Auxiliary Boiler (SN-02) this facility.

Auxiliary Boiler (SN-02)			
Pollutant	*BACT Determination*	*BACT Limit*	*Averaging Time*
PM/PM_{10}	Natural Gas Combustion	0.0076 lb/MMBtu[1]	3-hour
SO_2	Natural Gas Combustion	0.0006 lb/MMBtu	3-hour
VOC	Proper Design/Operation	0.0055 lb/MMBtu	3-hour
CO	Proper Design/Operation	400 ppmvd at 3% O_2[2]	30-day rolling
NO_x	Low NO_x Burner and Flue Gas Recirculation	0.11 lb/MMBtu	30-day rolling
Pb	Natural Gas combustion	N/A	N/A

[1] PM/PM_{10} rate based on 112(g) analysis will be set at 0.004 lb/MMBtu
[2] CO rate based on 112(g) analysis will be set at 0.036 lb/MMBtu

BACT Evaluation for Cooling Tower

PM/PM_{10} are emitted from cooling towers because the water circulating in the tower contains small amounts of dissolved solids (e.g., calcium, magnesium, etc.) that crystallize and form airborne particles as the water drift leaves the cooling tower. AP-42 Section 13.4 Wet Cooling Towers (1/95) PM_{10} emission factors are extremely conservative because most of the drift droplets will remain in liquid form until they reach the ground due to gravity. Advances in drift eliminator technology have greatly reduced the potential for cooling tower drift.

Drift eliminators will minimize particulate emissions from the cooling towers. Drift eliminators are designated as BACT for each cooling tower in the RBLC database. The RBLC presents a wide range of emission rates for cooling towers due to differences in type and operating characteristics. SWEPCO proposes high-efficiency drift eliminators as BACT for particulate emissions from the cooling towers with a drift rate of 0.001%. ADEQ has determined that a drift rate of 0.0005% is BACT.

Cooling Tower		
Pollutant	*Control Technology Determination*	*BACT Limit*
PM	High-efficiency drift eliminators	Drift rate of 0.0005%

BACT Evaluations for Diesel-Fired Emergency Generator and Fire Pump Engine

SWEPCO will construct and operate a diesel-fired emergency generator with a nominal power output capacity of 2 MW (2,682 hp) and two diesel-fired fire pump engines with a nominal power output capacity of 300 hp each. These sources will be operated for testing and emergencies only: operation of the emergency generator will not exceed 500 hours per year and operation of the fire pump engines will not exceed a total of 100 hours per year. EPA's RBLC was queried to identify controls for other similar-sized (between 0.5 and 5 MW) emergency generators and other fire pump diesel engines. The RBLC shows that no add-on controls have been installed for emergency generators or fire pump engines. That is, BACT for all pollutants for emergency generators and fire pump engines is a combination of proper design and operation (including one or all of ignition timing retard, turbo-charging, and after cooling), fuel specification (i.e. low-sulfur diesel), and operation limitations. Additionally, the RBLC shows that most emergency generators and fire pump engines have BACT/permit limits at or above the recently promulgated NSPS Subpart IIII. SWEPCO proposes the NSPS Subpart IIII limits as BACT for emissions of NO_x+NMHC, CO, and PM, as applicable. The proposed SO_2 limit is based on the use of low-sulfur (15 ppm) diesel fuel as required by NSPS Subpart IIII. The proposed BACT limits for the emergency generator and fire pump engine are summarized below.

Emergency Generator and Fire Pump Engines		
Pollutant	*Control Technology Determination*	*BACT Limit (g/kWh)*
NO_x + NMHC	Proper Design/Operation Fuel Specification – Low Sulfur Diesel Operation Limitation – 100 hrs/yr Fire Pump Engine 500 hrs/yr Emergency Generator	6.4
SO_2		0.007
PM		0.2
CO		3.5

BACT Evaluation for Material Transfer/Storage Operations

Particulate emissions will be generated by transport and storage of coal, lime, and fly ash/FGD waste. Based on a review of the RBLC database, the most stringent technologies for controlling

PM from such operations are forced-air dust collection (i.e., fabric filters or baghouses) and natural draft dust collection (i.e., bin vents). Where feasible, fabric filters or bin vents will be used to control PM emissions from major material handling silos and transfer points with a minimum control rate of 99 percent. Elsewhere, SWEPCO proposes to use currently accepted best industry practices for PM control, including the use of water and/or chemical suppressants and enclosures for buildings and conveyors.

112(g) Case by Case MACT

Section 112(g) of the Clean Air Act requires that the permitting authority determine a MACT emission limitation on a case-by-case basis for newly constructed major sources of HAPs for which no federal emission limitation has been promulgated. The SWEPCO facility will be a new major source for HAPs and is therefore required to undergo a case-by-case MACT determination.

Since SWEPCO is a new source of HAP, under 63.43,

> *The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority*
>
> *and*
>
> *Based upon available information, as defined in this subpart, the MACT emission limitation and control technology (including any requirements under paragraph (d)(3) of this section) recommended by the applicant and approved by the permitting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.*

This limits HAPs from the main boiler, SN-01 as well as the auxiliary boiler, SN-02. A summary of the emission rates follows.

Main Boiler, SN-01

Pollutant	Emission Limit	Averaging Time	Monitoring/Compliance
Mercury	1.7 lb/TBtu	12 month average	Continuous Emission Monitor
Lead	0.000016 lb/MMBtu	3-hour average	Annual Stack Test
Particulate HAPs as	0.012 lb/MMBtu	3-hour average	Annual Stack Test

PM_{10} (filterable):			
Particulate HAPs as PM_{10} (total)	0.025 lb/MMBtu	3-hour average	Annual Stack Test
Hydrogen Chloride	0.0006 lb/MMBtu	3-hour average	Annual Stack Test
Hydrogen Fluoride	0.0002 lb/MMBtu	3-hour average	Annual Stack Test
Organic HAPs as VOC	0.00078 lb/MMBtu[1]	3-hour average	Annual Stack Test

[1] Reduced from draft 112(g) permit proposed limit of 0.0025 lbs/**MMBtu**

Auxiliary Boiler, SN-02

Pollutant	Emission Limit	Averaging Time	Monitoring/Compliance
Inorganic HAPs as PM_{10} (total)	0.004 lb/MMBtu	3-hour average	Initial Stack Test
Organic HAPs as CO	0.036 lb/MMBtu	3-hour average	Initial Stack Test

Regulations

The following table contains the regulations applicable to this permit.

Regulations
Arkansas Air Pollution Control Code, Regulation 18, effective February 15, 1999
Regulations of the Arkansas Plan of Implementation for Air Pollution Control, Regulation 19, effective May 28, 2006
Regulations of the Arkansas Operating Air Permit Program, Regulation 26, effective September 26, 2002
40 CFR Part 52.21, Prevention of Significant Deterioration (PSD)
40 CFR Part 60, Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978*
40 CFR Subpart Db--*Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*
40 CFR Part 60, Subpart Y, *Standards of Performance for Coal Preparation Plants*
40 CFR Part 60, Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*
40 CFR Part 63, Subpart ZZZZ, *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

The following table is a summary of emissions from the facility. This table, in itself, is not an enforceable condition of the permit.

Emission Summary

EMISSION SUMMARY				
Source Number	Description	Pollutant	Emission Rates	
			lb/hr	tpy
Total Allowable Emissions		PM	188.2	801.56
		PM_{10}	172.0	732.26
		SO_2	480.5	2102.69
		VOC	15.3	23.08
		CO	937.3	3951.0
		NO_X	512.6	1336.6

	HAPs	Acetaldehyde*	0.25	0.96
		Acrolein*	0.13	0.5
		Antimony**	0.15	0.66
		Arsenic**	0.52	2.25
		Benzene*	0.53	2.17
		Benzyl Chloride*	0.27	1.15
		Beryllium**	0.02	0.08
		1,3-Butadiene*	0.02	0.02
		Cadmium**	0.03	0.09
		Carbon Disulfide	0.05	0.22
		Chloroform*	0.03	0.1
		Chromium**	0.19	0.77
		Chromium VI**	0.06	0.23
		Cobalt**	0.04	0.13
		Cyanide**	0.94	4.11
		Dichlorobenzene*	0.01	0.01
		Dimethyl Sulfate*	0.02	0.08
		Dioxins & Furans	0.01	0.01
		Formaldehyde*	0.18	0.44
		Hexane*	0.13	0.41
		Hydrogen Chloride	3.6	15.77
		Hydrogen Fluoride	1.2	5.26
		Lead**	0.097	0.42
		Manganese**	1.12	4.81
		Mercury	0.0102	0.0447
		Methylhydrazine*	0.07	0.28
		Nickel**	0.12	0.47
		Phenol*	0.01	0.03
		Phosphorous**	2.4	10.51
		POM*	0.04	0.07
		Propionaldehyde*	0.15	0.63
		Selenium**	0.25	1.06
		Sulfuric Acid	25.2	110.38
		Toluene*	0.02	0.02
		Xylene*	0.02	0.02
	Air Contaminants ***	Ammonia	37.5	164.4
SN	Description	Pollutant	lb/hr	tpy
01	Main Boiler	PM	150.0	657.0
		PM_{10}	150.0	657.0
		SO_2	480.0	2102.4
		VOC	4.7	20.5
		CO	900.0	3,942.0
		NO_x	420.0	1,314.0
		Acetaldehyde*	0.22	0.94

		Acrolein*	0.11	0.48
		Antimony**	0.15	0.66
		Arsenic**	0.51	2.24
		Benzene*	0.49	2.14
		Benzyl Chloride*	0.27	1.15
		Beryllium**	0.01	0.04
		Cadmium**	0.02	0.08
		Carbon Disulfide	0.05	0.22
		Chloroform*	0.03	0.1
		Chromium**	0.18	0.76
		Chromium VI**	0.06	0.23
		Cobalt**	0.03	0.12
		Cyanide**	0.94	4.11
		Dimethyl Sulfate*	0.02	0.08
		Dioxins & Furans	0.01	0.01
		Formaldehyde*	0.09	0.4
		Hexane*	0.03	0.11
		Hydrogen Chloride	3.6	15.8
		Hydrogen Fluoride	1.2	5.3
		Lead**	0.096	0.42
		Manganese**	1.11	4.8
		Mercury	0.0102	0.0447
		Methylhydrazine*	0.07	0.28
		Nickel**	0.11	0.46
		Phenol*	0.01	0.03
		Phosphorous**	2.4	10.51
		POM*	0.01	0.04
		Propionaldehyde*	0.15	0.63
		Selenium**	0.24	1.05
		Sulfuric Acid	25.2	110.4
		Ammonia***	37.5	164.4
02	Auxiliary Boiler	PM	2.3	0.6
		PM_{10}	2.22	0.55
		SO_2	0.4	0.1
		VOC	3.0	0.8
		CO	20.0	5.0
		NO_x	61.1	15.3
		Arsenic**	0.01	0.01
		Benzene*	0.01	0.01
		Beryllium**	0.01	0.01
		Cadmium**	0.01	0.01
		Chromium**	0.01	0.01
		Cobalt**	0.01	0.01
		Dichlorobenzene*	0.01	0.01
		Formaldehyde*	0.05	0.02

		Hexane*	0.1	0.3
		Lead**	0.01	0.01
		Manganese**	0.01	0.01
		Mercury	0.00014	0.000035
		Nickel**	0.01	0.01
		POM*	0.01	0.01
		Selenium**	0.01	0.01
03	Emergency Diesel Generator	PM	0.9	0.3
		PM_{10}	0.9	0.3
		SO_2	0.1	0.1
		VOC	6.8	1.7
		CO	15.5	3.9
		NO_x	28.3	7.1
		1,3-Butadiene*	0.01	0.01
		Acetaldehyde*	0.02	0.01
		Acrolein*	0.01	0.01
		Benzene*	0.02	0.01
		Formaldehyde*	0.03	0.01
		POM*	0.01	0.01
		Toulene*	0.01	0.01
		Xylene*	0.01	0.01
04	Fire Pump Diesel Engines	PM	0.1	0.1
		PM_{10}	0.1	0.1
		SO_2	0.1	0.1
		VOC	0.8	0.04
		CO	1.8	0.1
		NO_x	3.2	0.2
		1,3-Butadiene*	0.01	0.01
		Acetaldehyde*	0.01	0.01
		Acrolein*	0.01	0.01
		Benzene*	0.01	0.01
		Formaldehyde*	0.01	0.01
		POM*	0.01	0.01
		Toluene*	0.01	0.01
		Xylene*	0.01	0.01
EP-01	Coal Dumper Tunnel Exhaust Fan	PM	0.1	0.3
		PM_{10}	0.1	0.2
EP-02	Material Transfer (C-1 to C-3)	PM	0.3	1.0
		PM_{10}	0.2	0.5
EP-03	Material Transfer (C-1 to lowering well 1)	PM	0.3	1.0
		PM_{10}	0.2	0.5
EP-04	Material Transfer (C-3 to lowering well 2)	PM	0.3	1.0
		PM_{10}	0.2	0.5
EP-05	Coal Reclaim Tunnel Exhaust Fan	PM	0.1	0.3
		PM_{10}	0.1	0.2

EP-06	Coal Reclaim Tunnel Exhaust Fan	PM PM_{10}	0.1 0.1	0.3 0.2
EP-07	Coal Crusher House Exhaust Fan	PM PM_{10}	0.1 0.1	0.3 0.3
EP-08	Coal Crusher House Exhaust Fan	PM PM_{10}	0.1 0.1	0.3 0.2
EP-09	Coal Sample House Exhaust Fan	PM PM_{10}	0.1 0.1	0.1 0.1
EP-10	Coal Silo Wet Scrubber	PM PM_{10}	1.8 1.8	7.6 7.6
EP-15	Lime Vacuum Conveyor Exhauster	PM PM_{10}	0.3 0.3	1.2 1.2
EP-16	Lime Vacuum Conveyor (Railcar Unloading) Exhauster	PM PM_{10}	0.3 0.3	1.2 1.2
EP-17	Lime Silo Bin Vent Filter	PM PM_{10}	0.2 0.2	0.6 0.6
EP-18	Lime Day Bin Vent Filter	PM PM_{10}	0.2 0.2	0.6 0.6
EP-19	Lime Day Bin Vent Filter	PM PM_{10}	0.2 0.2	0.6 0.6
EP-20	Activated Carbon Bin Vent Filter	PM PM_{10}	0.2 0.2	0.7 0.7
EP-21	Fly Ash Waste Silo Bin Vent Filter	PM PM_{10}	0.2 0.2	0.6 0.6
EP-22	Fly Ash Recycle Bin Vent Filter	PM PM_{10}	0.2 0.2	0.6 0.6
EP-23	Fly Ash/FGD Vac Conveyor (to Waste Silo) Exhauster	PM PM_{10}	0.3 0.3	1.2 1.2
EP-24	Fly Ash/FGD Vac Conveyor (to Recycle Silo) Exhauster	PM PM_{10}	0.3 0.3	1.2 1.2
TP-11	Coal Crusher House Surge Bin Vent Filter	PM PM_{10}	0.1 0.1	0.4 0.4
TP-12	Coal Crusher House Bin Vent Filter	PM PM_{10}	0.1 0.1	0.4 0.4
TP-18	Material Transfer (C-6A to C-7A)	These Sources Vent to SN-EP-10		
TP-19	Material Transfer (C-6B to C-7B)			
TP-20	Material Transfer (C-7A to storage silos)			
TP-21	Material Transfer (C-7B to storage silos)			
TP-22	Material Transfer (Fly Ash/FGD Waste to Truck)	PM PM_{10}	0.1 0.1	0.2 0.1

TP-23	Fly Ash Disposal to Landfill	PM PM_{10}	0.1 0.1	0.2 0.1
F-01	Active Coal Pile	PM PM_{10}	0.2 0.1	0.8 0.4
F-02	Active Coal Pile	PM PM_{10}	0.2 0.1	0.8 0.4
F-03	Dozing Coal – Active and Inactive Pile	PM PM_{10}	2.1 0.4	9.4 1.5
F-04	Inactive Coal Pile	PM PM_{10}	2.3 1.2	10.1 5.1
F-05	Dozing of Solid Waste Disposal Area	PM PM_{10}	10.7 3.3	46.9 14.3
F-06	Solid Waste Disposal Storage	PM PM_{10}	4.4 1.6	19.0 6.7
CT-01	Cooling Tower	PM PM_{10}	5.2 5.2	22.8 22.8
RD-01	Roads	PM PM_{10}	3.8 1.1	11.9 3.3

*HAPs included in the VOC totals. Other HAPs are not included in any other totals unless specifically stated.
**HAPs included in the PM totals.
***Air Contaminants such as ammonia, acetone, and certain halogenated solvents are not VOCs or HAPs.

SECTION III: PERMIT HISTORY

This is the initial permit for this facility.

SECTION IV: SPECIFIC CONDITIONS

SN-01
Main Boiler

Source Description

An ultra-supercritical pulverized coal (PC) boiler (600 MW) produces steam at temperatures above 1100 °F to drive a condensing steam turbine to generate electricity. The PC boiler burns sub-bituminous coal as the main fuel and uses natural gas for startup and flame stabilization.

Specific Conditions

1. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with the SO_2, CO and NO_x limits through use of Continuous Emission Monitors (CEM) required in Specific Conditions 11 and 12 . Compliance with the PM_{10}, VOC, Pb and Sulfuric Acid (H_2SO_4) limits shall be demonstrated through compliance with the testing requirements of Specific Condition 7 . [Regulation 19, §19.901 et seq., effective October 15, 2007 and 40 CFR Part 52, Subpart E, Regulation 19, §19.304 and 40 CFR 63.43]

Pollutant	lb/hr	tpy
PM_{10}	150.0	657.0
SO_2	480.0	2102.4
VOC	4.7	20.5
CO	900.0	3,942.0
NO_x	420.0	1,314.0
Pb (Lead)*	0.096	0.42
Sulfuric Acid (H_2SO_4)	25.2	110.4

*emission rate also included in PM_{10} emission rate

2. The permittee shall not exceed the emission rates set forth in the following table. The permittee shall demonstrate compliance with the PM emission rate through compliance with Specific Condition 7. Compliance with the Mercury emission limits shall be demonstrated through the use of CEM required in Specific Condition 13. Hydrogen Chloride and Hydrogen Fluoride emission rates shall be demonstrated through compliance with Specific Condition 8. Compliance with the emission rates for the other compounds listed shall be demonstrated through compliance with Specific Condition 10. [Regulation No. 19 §19.304 and 40 CFR 63 and Regulation 18, §18.801, effective

February 15, 1999, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
PM	150	657
Acetaldehyde*	0.22	0.94
Acrolein*	0.11	0.48
Antimony**	0.15	0.66
Arsenic**	0.51	2.24
Benzene*	0.49	2.14
Benzyl Chloride*	0.27	1.15
Beryllium**	0.01	0.04
Cadmium**	0.02	0.08
Carbon Disulfide	0.05	0.22
Chloroform*	0.03	0.1
Chromium**	0.18	0.76
Chromium VI**	0.06	0.23
Cobalt**	0.03	0.12
Cyanide**	0.94	4.11
Dimethyl Sulfate*	0.02	0.08
Dioxins & Furans*	0.01	0.01
Formaldehyde*	0.09	0.4
Hexane*	0.03	0.11
Hydrogen Chloride	3.6	15.77
Hydrogen Fluoride	1.2	5.26
Manganese**	1.11	4.8
Mercury	0.0102***	0.0447
Methylhydrazine*	0.07	0.28
Nickel**	0.11	0.46
Phenol*	0.01	0.03
Phosphorous**	2.4	10.51
POM**	0.01	0.04
Propionaldehyde*	0.15	0.63
Selenium**	0.24	1.05

* Included in the VOC total
** Included in the PM total
*** Annual average

3. The permittee shall not exceed the emission rates set forth in the following table. Compliance with the emission rates shall be demonstrated through compliance with Specific Condition 9. [Regulation 18, §18.801, effective February 15, 1999, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Pollutant	lb/hr	tpy
Ammonia	37.5	164.4

4. The permittee shall not discharge into the atmosphere from SN-01 gases which exhibit an opacity greater than 10% (6-minute average) except for one 6-minute period per hour (during any 60 minute consecutive period) of not more than 27% as measured using EPA Reference Method 9. Compliance with this condition shall be demonstrated by comparison of the limit to the 6-minute average opacity reading obtained from the COMS installed in accordance with Specific Condition 11. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

5. The permittee shall not exceed the BACT emission limits set forth in the following table. Compliance with SO_2, CO and NO_x emission rates shall be demonstrated by use of CEMs required in Specific Conditions 11and 12. Compliance with other limits shall be demonstrated by the testing requirements of Specific Condition 7. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	*BACT Limit*	*Averaging period*
PM/ PM_{10} (filterable)	0.012 lb/MMBtu	3-hour
PM_{10} (total)	0.025 lb/MMBtu	3-hour
SO_2	0.08 lb/MMBtu While combusting coal with a sulfur content greater than 0.45% by weight	30-day rolling average
	0.065 lb/MMBtu While combusting coal with a sulfur content less than or equal to 0.45% by weight	30-day rolling average
	480 lbs/hr	24 hour rolling average
VOC	0.0036 lb/MMBtu[1]	3-hour
CO	0.15 lb/MMBtu	30-day rolling
NO_x	0.067 lb/MMBtu for normal operations [2]	24-hour rolling average
	420 lbs/hr	24 hour rolling average

	0.05 lb/MMBtu	Annual average
Pb (Lead)	2.6E-5 lb/MMBtu [3]	3-hour
H_2SO_4 Mist	0.0042 lb/MMBtu	3-hour

[1] VOC rate based on 112(g) analysis will be set at 0.00078 lb/MMBtu
[2] Normal operation is defined as operation at or above 300 MW gross output from the Unit 1 generator
[3] Pb rate based on 112(g) analysis will be set at 1.6 E-05 lb/MMBtu

6. The permittee shall not exceed the emission rates set forth in the following table for SN-01 (Main Boiler). Compliance with the Mercury emission limits shall be demonstrated through use of the CEM required in Specific Condition 13. Compliance with other limits shall be demonstrated by the testing requirements of Specific Conditions 7 and 8. [Regulation No. 19 §19.304 and 40 CFR 63]

Pollutant	Emission Limit	Averaging Time
Mercury	1.7 lb/TBtu	12 month average
Lead	0.000016 lb/MMBtu	3-hour average
PM_{10} (filterable)	0.012 lb/MMBtu	3-hour average
PM_{10} (total)	0.025 lb/MMBtu	3-hour average
Hydrogen Chloride	0.0006 lb/MMBtu	3-hour average
Hydrogen Fluoride	0.0002 lb/MMBtu	3-hour average
VOC	0.00078 lb/MMBtu	3-hour average

7. The permittee shall conduct testing at SN-01 to determine the emission rates for PM, PM_{10}, VOC, Pb and Sulfuric Acid (H_2SO_4). This testing shall be performed in accordance with Plantwide Condition 3. This testing shall be repeated on an annual basis. Testing shall be performed in accordance with the methods listed in the following table or a Department approved alternative. A copy of these test results shall be submitted in accordance with General Provision 7. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	EPA Reference Method
PM Filterable and PM_{10} Filterable	5 or 17
PM Total and PM_{10} Total	5 and 202 or 17 and 202
VOC	25 or 25A
Pb	12 or 29
Sulfuric Acid (H_2SO_4)	8 or Controlled Condensate Method

8. The permittee shall conduct testing at SN-01 to determine the emission rates for Hydrogen Chloride and Hydrogen Fluoride. This testing shall be performed in accordance with Plantwide Condition 3. This testing shall be repeated on an annual basis. Testing shall be performed in accordance with the methods listed in the following table or a Department approved alternative. A copy of these test results shall be submitted in accordance with General Provision 7. [Regulation 19, §19.901 et seq. and 40 CFR Part 52, Subpart E]

Pollutant	EPA Reference Method
Hydrogen Chloride	26
Hydrogen Fluoride	

9. The permittee shall conduct testing at SN-01 to determine compliance with the emission rate for Ammonia. This testing shall be performed in accordance with Plantwide Condition 3. This testing shall be repeated on an annual basis. Testing shall be performed in accordance with the methods listed in the following table or a Department approved alternative. A copy of these test results shall be submitted in accordance with General Provision 7.

Pollutant	EPA Reference Method
Ammonia	CTM-027

10. The permittee shall conduct an initial test at SN-01 to determine compliance with the emission rates for all other pollutants listed in Specific Condition 2 not otherwise requiring a CEM or specific testing (i.e. all pollutants except PM, Ammonia, Hydrogen Chloride, Hydrogen Fluoride and Mercury). This testing shall be performed in accordance with Plantwide Condition 3. Testing shall be performed in accordance with testing protocols submitted by the applicant and approved by the Department in advance. A copy of these test results shall be submitted in accordance with General Provision 7. [Regulation No. 19 §19.304 and 40 CFR 63 and Regulation 18, §18.801, effective February 15, 1999, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

11. This source is considered an affected source under 40 CFR Part 60, Subpart Da, *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978,* and is subject, but not limited to, the following conditions. [Regulation 19, §19.304 and 40 CFR Part 60, Subpart Da]

a) On and after the date the particulate matter performance test required to be conducted under 40 CFR 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity.

b) On and after the date on which the performance test required to be conducted under 40 CFR 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification is commenced after February 28, 2005, except for modified affected facilities meeting the requirements of paragraph (d) of 40 CFR 60.42Da, any gases that contain particulate matter in excess of either:
    i. 18 ng/J (0.14 lb/MWh) gross energy output; or
    ii. 6.4 ng/J (0.015 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.

c) On and after the date on which the performance test required to be conducted under 40 CFR 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except as provided for under paragraphs (j) or (k) of 40 CFR 60.43Da, any gases that contain sulfur dioxide in excess of the applicable emission limitation specified in paragraphs (i)(1) through (3) of CFR 60.43Da(h):
    i. For an affected facility for which construction commenced after February 28, 2005, any gases that contain sulfur dioxide in excess of either:
        1. 180 ng/J (1.4 lb/MWh) gross energy output on a 30-day rolling average basis, or
        2. 5 percent of the potential combustion concentration (95 percent reduction) on a 30-day rolling average basis.

d) On and after the date on which the performance test required to be conducted under 40 CFR 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, reconstruction, or modification commenced after February 28, 2005, except for an IGCC meeting the requirements of paragraph (f) of this section, any gases that contain nitrogen oxides (expressed as NO2) in excess of the applicable emission limitation specified in paragraphs (e)(1) through (3) of 40 CFR 60.44Da(e):
    i. For an affected facility for which construction commenced after February 28, 2005, the owner or operator shall not cause to be discharged into the atmosphere any gases that contain nitrogen oxides (expressed as NO2) in excess of 130 ng/J (1.0 lb/MWh) gross energy output on a 30-day rolling average basis, except as provided under §60.48Da(k).

e) For each coal-fired electric utility steam generating unit other than an integrated gasification combined cycle (IGCC) electric utility steam generating unit, on and after the date on which the initial performance test required to be conducted under §60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility for which construction, modification, or reconstruction commenced after January 30, 2004, any gases which contain mercury (Hg) emissions in excess of each Hg emissions limit in paragraphs (a)(1) through (5) of 40 CFR 60.45Da that applies to you. The Hg emissions limits in paragraphs (a)(1) through (5) 40 CFR 60.45Da are based on a 12-month rolling average using the procedures in §60.50Da(h).

i. For each coal-fired electric utility steam generating unit that burns only sub bituminous coal:
   1. If your unit is located in a county-level geographical area receiving greater than 25 inches per year (in/yr) mean annual precipitation, based on the most recent publicly available U.S. Department of Agriculture 30-year data, you must not discharge into the atmosphere any gases from a new affected source which contain Hg in excess of 66×10^{-6} lb/MWh or 0.066 lb/GWh on an output basis. The SI equivalent is 0.0083 ng/J.

f) The particulate matter emission standards under 40 CFR 60.42Da, the nitrogen oxides emission standards under 40 CFR 60.44Da, and the Hg emission standards under 40 CFR 60.45Da apply at all times except during periods of startup, shutdown, or malfunction.

g) During emergency conditions in the principal company, an affected facility with a malfunctioning flue gas desulfurization system may be operated if sulfur dioxide emissions are minimized by:
   i. Operating all operable flue gas desulfurization system modules, and bringing back into operation any malfunctioned module as soon as repairs are completed,
   ii. Bypassing flue gases around only those flue gas desulfurization system modules that have been taken out of operation because they were incapable of any sulfur dioxide emission reduction or which would have suffered significant physical damage if they had remained in operation, and
   iii. Designing, constructing, and operating a spare flue gas desulfurization system module for an affected facility larger than 365 MW (1,250 million Btu/hr) heat input (approximately 125 MW electrical output capacity). The Administrator may at his discretion require the owner or operator within 60 days of notification to demonstrate spare module capability. To demonstrate this capability, the owner or operator must demonstrate compliance with the appropriate requirements under paragraph (a), (b), (d), (e), and (h) under 40 CFR 60.43Da for any period of operation lasting from 24 hours to 30 days when:
      1. Any one flue gas desulfurization module is not operated, The affected facility is operating at the maximum heat input rate,
      2. The fuel fired during the 24-hour to 30-day period is representative of the type and average sulfur content of fuel used over a typical 30-day period, and
      3. The owner or operator has given the Administrator at least 30 days notice of the date and period of time over which the demonstration will be performed.

h) After the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide emission limitations and percentage reduction requirements under §60.43Da and the nitrogen oxides emission limitations under §60.44Da is based on the average emission rate for 30 successive boiler operating days. A separate performance test is completed at the end of each boiler operating day after the initial performance test, and a new 30 day average emission rate for both sulfur dioxide and nitrogen oxides and a new percent reduction for sulfur dioxide are calculated to show compliance with the standards.

i) For the initial performance test required under 40 CFR 60.8, compliance with the sulfur dioxide emission limitations and percent reduction requirements under 40 CFR 60.43Da and the nitrogen oxides emission limitation under 40 CFR 60.44Da is based on the average emission rates for sulfur dioxide, nitrogen oxides, and percent reduction for sulfur dioxide for the first 30 successive boiler operating days. The initial performance test is the only test in which at least 30 days prior notice is required unless otherwise specified by the Administrator. The initial performance test is to be scheduled so that the first boiler operating day of the 30 successive boiler operating days is completed within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility.

j) The owner or operator of an affected facility subject to emission limitations in this subpart shall determine compliance as follows:

    i. Compliance with applicable 30-day rolling average SO_2 and NO_x emission limitations is determined by calculating the arithmetic average of all hourly emission rates for SO_2 and NO_x for the 30 successive boiler operating days, except for data obtained during startup, shutdown, malfunction (NO_x only), or emergency conditions (SO_2) only.
    ii. Compliance with applicable SO_2 percentage reduction requirements is determined based on the average inlet and outlet SO_2 emission rates for the 30 successive boiler operating days.
    iii. Compliance with applicable daily average particulate matter emission limitations is determined by calculating the arithmetic average of all hourly emission rates for particulate matter each boiler operating day, except for data obtained during startup, shutdown, and malfunction.

k) If an owner or operator has not obtained the minimum quantity of emission data as required under §60.49Da of this subpart, compliance of the affected facility with the emission requirements under Secs. 40 CFR 60.43Da and 40 CFR 60.44Da of this subpart for the day on which the 30-day period ends may be determined by the Administrator by following the applicable procedures in section 7 of Method 19.[44 FR 33613, June 11, 1979, as amended at 54 FR 6664, Feb. 14, 1989]

    i. Compliance provisions for sources subject to 40 CFR 60.44Da(d)(1), (e)(1), or (f). The owner or operator of an affected facility subject to 40 CFR 60.44Da(d)(1) or (e)(1) shall calculate NO_x emissions by multiplying the average hourly NO_x output concentration, measured according to the provisions of 40 CFR 60.49Da(c), by the average hourly flow rate, measured according to the provisions of 40 CFR 60.49Da(l), and dividing by the average hourly gross energy output, measured according to the provisions of 40 CFR 60.49Da(k).

l) As an alternative to meeting the compliance provisions specified in paragraph (o) of 40 CFR 60.47Da, an owner or operator may elect to install, certify, maintain, and operate a continuous emission monitoring system measuring particulate matter emissions discharged from the affected facility to the atmosphere and record the output of the system as specified in paragraphs (p)(1) through (p)(8) of 40 CFR 60.47Da.

i. The owner or operator shall submit a written notification to the Administrator of intent to demonstrate compliance with this subpart by using a continuous monitoring system measuring particulate matter. This notification shall be sent at least 30 calendar days before the initial startup of the monitor for compliance determination purposes. The owner or operator may discontinue operation of the monitor and instead return to demonstration of compliance with this subpart according to the requirements in paragraph (o) of 40 CFR 60.47Da by submitting written notification to the Administrator of such intent at least 30 calendar days before shutdown of the monitor for compliance determination purposes.

ii. Each continuous emission monitor shall be installed, certified, operated, and maintained according to the requirements in 40 CFR 60.49Da(v).

iii. The initial performance evaluation shall be completed no later than 180 days after the date of initial startup of the affected facility, as specified under 40 CFR 60.8 of subpart A of this part or within 180 days of the date of notification to the Administrator required under paragraph 40 CFR 60.47Da (p)(1) of this section, whichever is later.

iv. Compliance with the applicable emissions limit shall be determined based on the 24-hour daily (block) average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 24-hour block arithmetic average emission concentration shall be calculated using EPA Reference Method 19, section 4.1.

v. At a minimum, valid continuous monitoring system hourly averages shall be obtained for 90 percent of all operating hours on a 30-day rolling average.

    1. At least two data points per hour shall be used to calculate each 1-hour arithmetic average.
    2. Reserved]

vi. The 1-hour arithmetic averages required shall be expressed in ng/J, MMBtu/h, or lb/MWh and shall be used to calculate the boiler operating day daily arithmetic average emission concentrations. The 1-hour arithmetic averages shall be calculated using the data points required under 40 CFR 60.13(e)(2) of subpart A of this part.

vii. All valid continuous monitoring system data shall be used in calculating average emission concentrations even if the minimum continuous emission monitoring system data requirements of paragraph 40 CFR 60.48Da (j)(5) are not met.

viii. When particulate matter emissions data are not obtained because of continuous emission monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments, emissions data shall be obtained by using other monitoring systems as approved by the Administrator or EPA Reference Method 19 to provide, as necessary, valid emissions data for a minimum of 90 percent of all operating hours per 30-day rolling average.

m) Except as provided for in paragraphs (t) and (u) of 40 CFR 60.49Da, the owner or operator of an affected facility, shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the opacity of emissions discharged to the atmosphere, except where gaseous fuel is the only fuel combusted. If opacity interference due to water droplets exists in the stack (for example, from the use of an FGD system), the opacity is monitored upstream of the interference (at the inlet to the FGD system). If opacity interference is experienced at all locations (both at the inlet and outlet of the sulfur dioxide control system), alternate parameters indicative of the particulate matter control system's performance are monitored (subject to the approval of the Administrator).

n) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring sulfur dioxide emissions, except where natural gas is the only fuel combusted, as follows:
    i. Sulfur dioxide emissions are monitored at both the inlet and outlet of the sulfur dioxide control device.
    ii. For a facility that qualifies under the numerical limit provisions of 40 CFR 60.43Da(d), (i), (j), or (k) sulfur dioxide emissions are only monitored as discharged to the atmosphere.
    iii. An "as fired" fuel monitoring system (upstream of coal pulverizers) meeting the requirements of Method 19 may be used to determine potential sulfur dioxide emissions in place of a continuous sulfur dioxide emission monitor at the inlet to the sulfur dioxide control device as required under paragraph (b)(1) of 40 CFR 60.49Da.

o) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring nitrogen oxides emissions discharged to the atmosphere; or
    ii. If the owner or operator has installed a nitrogen oxides emission rate continuous emission monitoring system (CEMS) to meet the requirements of part 75 of this chapter and is continuing to meet the ongoing requirements of part 75 of this chapter, that CEMS may be used to meet the requirements of 40 CFR 60.49Da, except that the owner or operator shall also meet the requirements of 40 CFR 60.51Da. Data reported to meet the requirements of 40 CFR 60.51Da shall not include data substituted using the missing data procedures in subpart D of part 75 of this chapter, nor shall the data have been bias adjusted according to the procedures of part 75 of this chapter.

p) The owner or operator of an affected facility shall install, calibrate, maintain, and operate a continuous monitoring system, and record the output of the system, for measuring the oxygen or carbon dioxide content of the flue gases at each location where sulfur dioxide or nitrogen oxides emissions are monitored.

q) The continuous monitoring systems under paragraphs (b), (c), and (d) of this 40 CFR 60.49Da(e) are operated and data recorded during all periods of operation of the affected facility including periods of startup, shutdown, malfunction or emergency conditions, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

r) For units that began construction, reconstruction, or modification after February 28, 2005, the owner or operator shall obtain emission data for at least 90 percent of all operating hours for each 30 successive boiler operating days. If this minimum data requirement cannot be met with a continuous monitoring system, the owner or operator shall supplement emission data with other monitoring systems approved by the Administrator or the reference methods and procedures as described in paragraph (h) of 40 CFR 60.49Da.

s) The 1-hour averages required under paragraph 40 CFR 60.13(h) are expressed in ng/J (lb/million Btu) heat input and used to calculate the average emission rates under §60.48Da. The 1-hour averages are calculated using the data points required under 40 CFR 60.13(b). At least two data points must be used to calculate the 1-hour averages.

t) The owner or operator shall prepare and submit to the Administrator for approval a unit-specific monitoring plan for each monitoring system, at least 45 days before commencing certification testing of the monitoring systems. The owner or operator shall comply with the requirements in your plan. The plan must address the requirements in paragraphs (1) through (6) 40 CFR 60.49Da.

    i. Installation of the CEMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of the exhaust emissions (e.g., on or downstream of the last control device);
    ii. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems;
    iii. Performance evaluation procedures and acceptance criteria (e.g., calibrations, relative accuracy test audits (RATA), etc.);
    iv. Ongoing operation and maintenance procedures in accordance with the general requirements of 40 CFR 60.13(d) or part 75 of this chapter (as applicable);
    v. Ongoing data quality assurance procedures in accordance with the general requirements of 40 CFR 60.13 or part 75 of this chapter (as applicable); and
    vi. Ongoing record keeping and reporting procedures in accordance with the requirements of this subpart.

u) For sulfur dioxide, nitrogen oxides, particulate matter, and Hg emissions, the performance test data from the initial and subsequent performance test and from the performance evaluation of the continuous monitors (including the transmissometer) are submitted to the Administrator.

v) The owner or operator of an affected facility subject to the emissions limitations in 40 CFR 60.45Da or 40 CFR 60.46Da shall provide notifications in accordance with §60.7(a) and shall maintain records of all information needed to demonstrate compliance including performance tests, monitoring data, fuel analyses, and calculations, consistent with the requirements of Sec.60.7(f).

12. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for SN-01 and record the output of the system to measure CO. The CEMS shall comply with the Department "Continuous Emissions Monitoring

Systems Conditions." The CEMS data may be used by the Department for enforcement purposes. [Regulation 19, §19.702 et seq, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

13. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) for SN-01 and record the output of the system to measure Mercury (Hg). The CEMS shall comply with the attached Department "Continuous Emissions Monitoring Systems Conditions", attached. The CEMS data may be used by the Department for enforcement purposes. [Regulation 19, §19.702 et seq, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

14. The permittee shall maintain monthly records of the average lb/MMBtu mercury emission rate. These records shall include the average rate for the preceding consecutive 12 month period. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

15. The permittee must install and continuously operate a bag leak detection system for SN-01. [Regulation 19, §19.705 and 40 CFR 70.6]

a) The bag leak detection system must be certified by the manufacturer to be capable of continuously detecting and recording particulate matter emissions at concentrations of 1.0 milligrams per actual cubic meter;
b) The bag leak detection system shall provide output of relative or absolute particulate matter loadings;
c) The bag leak detection system shall be equipped with an alarm system that will sound an audible alarm when an increase in relative particulate loadings is detected over a preset level;
d) The bag leak detection system shall be installed and operated in a manner consistent with available written guidance from the U.S. Environmental Protection Agency or, in the absence of such written guidance, the manufacturer's written specifications and recommendations for installation, operation, and adjustment of the system;
e) The initial adjustment of the system shall, at a minimum, consist of establishing the baseline output by adjusting the sensitivity (range) and the averaging period of the device, and establishing the alarm set points and the alarm delay time;
f) Following initial adjustment, the permittee must not adjust the sensitivity or range, averaging period, alarm set points, or alarm delay time, except as detailed in the operation and maintenance plan required. The permittee must not increase the sensitivity by more than 100 percent or decrease the sensitivity by more than 50 percent over a 365 day period unless such adjustment follows a complete fabric filter inspection which demonstrates the fabric filter is in good operating condition.

16. The permittee shall establish an operating and maintenance plan that specifies the procedures to follow in the case of a bag leak detection system alarm or malfunction. The corrective measures plan must include, at a minimum, the procedures used to determine and record the time and cause of the alarm or bag leak detection system malfunction as

well as the corrective measures taken to correct the control device or bag leak detection system malfunction or to minimize emissions.

a) The procedures used to determine the cause of the alarm or bag leak detection system malfunction must be initiated within 30 minutes of the time the alarm first sounds; and
b) The cause of the alarm or bag leak detection system malfunction must be alleviated by taking the necessary corrective measure(s) which may include, but are not to be limited to, the following:
c) Inspecting the fabric filter for air leaks, torn or broken filter elements, or any other malfunction that may cause an increase in emissions;
d) Sealing off defective bags or filter media;
e) Replacing defective bags or filter media, or otherwise repairing the control device;
f) Sealing off a defective fabric filter compartment;
g) Cleaning the bag leak detection system probe, or otherwise repairing the bag leak detection system; or
h) Shutting down the boiler.

17. The permittee shall maintain records of hourly bag leak detector readings. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

18. The permittee shall not exceed a 24 hour rolling average heat input to SN-01 of 6000 MMBtu. [Regulation 19, §19.901 et seq. and A.C.A.§8-4-203 as referenced by A.C.A.§8-4-304, and 40 CFR 70.6]

19. The permittee shall maintain hourly and 24 hour records of the heat input to SN-01. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

20. The permittee shall maintain records of coal sulfur weight percent combusted in SN-01 on a 30 day rolling average. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

21. The permittee shall maintain records of the following averages. These records shall be updated by the 15th day of the month after the month which the records represent, be kept on site, and be made available to Department personnel upon request. Reports of these records shall be submitted in accordance with General Provision 7. [Regulation 19, §19.705 and 40 CFR 70.6]

Pollutant	Rate	Averaging Period
SO_2	lb/MMBtu	30-day rolling average
	lb/hr	24-hour rolling average
NO_x	lb/MMBtu for normal operations [1]	24-hour rolling average
	lbs/hr	24 hour rolling average
	lb/MMBtu	12 month rolling average
CO	lb/MMBtu	30-day rolling average
Mercury	lb/TBtu	12 month rolling average

[1] Normal operation is defined as operation at or above 300 MW gross output from the Unit 1 generator

Acid Rain Program

22. The affected unit (SN-01) is subject to and shall comply with applicable provisions of the Acid Rain Program (40 CFR Parts 72, 73, and 75).

23. The submission of the NO_X, SO_2, and O_2 or CO_2 monitoring plan is required at least 45 days prior to the CEMS certification testing. Notice of CEMS certification testing is required at least 21 days prior to the CEMS certification testing. [40 CFR Part 75-Continuous Emission Monitoring Subpart G]

24. The initial NO_X, and O_2 or CO_2 CEMS certification testing is to occur no later than 90 days after the unit commences commercial operation except the testing must occur prior to the date this unit is declared commercial in accordance with DOE Form EIA-860. [40 CFR Part 75 Subpart A]

25. The permittee shall ensure that the continuous emissions monitoring systems are in operation and monitoring all unit emissions at all times, except during periods of calibration, quality assurance, preventative maintenance or repair. [40 CFR §75.10]

SECTION V: COMPLIANCE PLAN AND SCHEDULE

This is the initial permit for the John W. Turk, Jr. Power Plant. The facility will examine and analyze future regulations that may apply and determine their applicability with any necessary action taken on a timely basis.

SECTION VI: PLANTWIDE CONDITIONS

1. The permittee shall notify the Director in writing within thirty (30) days after commencing construction, completing construction, first placing the equipment and/or facility in operation, and reaching the equipment and/or facility target production rate. [Regulation 19, §19.704, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

2. If the permittee fails to start construction within eighteen months or suspends construction for eighteen months or more, the Director may cancel all or part of this permit. [Regulation 19, §19.410(B) and 40 CFR Part 52, Subpart E]

3. The permittee must test any equipment scheduled for testing, unless stated in the Specific Conditions of this permit or by any federally regulated requirements, within the following time frames: (1) new equipment or newly modified equipment within sixty (60) days of achieving the maximum production rate, but no later than 180 days after initial start up of the permitted source or (2) operating equipment according to the time frames set forth by the Department or within 180 days of permit issuance if no date is specified. The permittee must notify the Department of the scheduled date of compliance testing at least fifteen (15) days in advance of such test. The permittee shall submit the compliance test results to the Department within thirty (30) days after completing the testing. [Regulation 19, §19.702 and/or Regulation 18 §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

4. The permittee must provide: [Regulation 19, §19.702 and/or Regulation 18, §18.1002 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

    a. Sampling ports adequate for applicable test methods;
    b. Safe sampling platforms;
    c. Safe access to sampling platforms; and
    d. Utilities for sampling and testing equipment.

5. The permittee must operate the equipment, control apparatus and emission monitoring equipment within the design limitations. The permittee shall maintain the equipment in good condition at all times. [Regulation 19, §19.303 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

6. This permit subsumes and incorporates all previously issued air permits for this facility. [Regulation 26 and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

7. The permittee shall comply with all applicable requirements contained in 40 CFR 63, Subpart A. [Regulation No. 19 §19.304 and 40 CFR 63.43(g)(2)(iv)]

8. The permittee must prepare and implement a Startup, Shutdown, and Malfunction Plan (SSM) for SN-01 and SN-02. If the Department requests a review of the SSM, the

permittee will make the SSM available for review. The permittee must keep a copy of the SSM at the source's location and retain all previous versions of the SSM plan for five years. [Regulation 19, §19.304 and 40 CFR 63.6(e)(3)]

9. The CEMS required by this permit shall be operated in accordance with all applicable conditions of the Department's Continuous Emission Monitoring Systems Conditions as found in Appendix F of this permit. [Regulation 19, §19.703, 40 CFR Part 52, Subpart E, and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Title VI Provisions

10. The permittee must comply with the standards for labeling of products using ozone-depleting substances. [40 CFR Part 82, Subpart E]

    a. All containers containing a class I or class II substance stored or transported, all products containing a class I substance, and all products directly manufactured with a class I substance must bear the required warning statement if it is being introduced to interstate commerce pursuant to §82.106.
    b. The placement of the required warning statement must comply with the requirements pursuant to §82.108.
    c. The form of the label bearing the required warning must comply with the requirements pursuant to §82.110.
    d. No person may modify, remove, or interfere with the required warning statement except as described in §82.112.

11. The permittee must comply with the standards for recycling and emissions reduction, except as provided for MVACs in Subpart B. [40 CFR Part 82, Subpart F]

    a. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156.
    b. Equipment used during the maintenance, service, repair, or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158.
    c. Persons performing maintenance, service repair, or disposal of appliances must be certified by an approved technician certification program pursuant to §82.161.
    d. Persons disposing of small appliances, MVACs, and MVAC like appliances must comply with record keeping requirements pursuant to §82.166. ("MVAC like appliance" as defined at §82.152)
    e. Persons owning commercial or industrial process refrigeration equipment must comply with leak repair requirements pursuant to §82.156.
    f. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

12. If the permittee manufactures, transforms, destroys, imports, or exports a class I or class II substance, the permittee is subject to all requirements as specified in 40 CFR Part 82, Subpart A, Production and Consumption Controls.

13. If the permittee performs a service on motor (fleet) vehicles when this service involves ozone depleting substance refrigerant (or regulated substitute substance) in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners.

    The term "motor vehicle" as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed. The term "MVAC" as used in Subpart B does not include the air tight sealed refrigeration system used as refrigerated cargo, or the system used on passenger buses using HCFC 22 refrigerant.

14. The permittee can switch from any ozone depleting substance to any alternative listed in the Significant New Alternatives Program (SNAP) promulgated pursuant to 40 CFR Part 82, Subpart G.

Acid Rain (Title IV)

15. The Director prohibits the permittee to cause any emissions exceeding any allowances the source lawfully holds under Title IV of the Act or the regulations promulgated under the Act. No permit revision is required for increases in emissions allowed by allowances acquired pursuant to the acid rain program, if such increases do not require a permit revision under any other applicable requirement. This permit establishes no limit on the number of allowances held by the permittee. However, the source may not use allowances as a defense for noncompliance with any other applicable requirement of this permit or the Act. The permittee will account for any such allowance according to the procedures established in regulations promulgated under Title IV of the Act. [Regulation 26, §26.701 and 40 CFR 70.6(a)(4)]

Mitigation of Visibility Impacts in Federal Class I Areas

16. Not later than twelve (12) months after the initial commencement [or "startup"] of operation of the main boiler (SN-01) at the Permittee's John W. Turk, Jr. Power Plant, SWEPCO shall obtain a final revision of Permit No. PSD-TX-3 for Unit 2 at the SWEPCO's Welsh Power Plant located in Pittsburg, Titus County, Texas from the Texas Commission on Environmental Quality (TCEQ) containing a federally enforceable emissions limitation of no more than 2,165 pounds of SO_2 per hour on a 24-hour rolling average basis, and a maximum of 9,483 tons per year. Within the same time frame as the first sentence in this paragraph, SWEPCO shall also secure from TCEQ a final action incorporating the emissions limitations described in this paragraph as federally enforceable emission limitations in the Welsh Plant's Federal (Title V) Operating Permit. SWEPCO shall submit a copy of such permits to the Department and the United States

Forest Service within thirty (30) days of issuance of the Welsh Unit 2 permits. Within the same time frame as the first sentence in this paragraph, SWEPCO shall submit emissions data demonstrating that SWEPCO has achieved and maintained compliance with an emission rate of no more than 2,165 pounds of SO_2 per hour on a 24-hour rolling average basis at Welsh Unit 2 for a period of at least thirty (30) days after the effective date for those federally enforceable emission limitations. Lastly, SWEPCO shall submit emissions data demonstrating compliance with an emission rate of no more than 2,165 pounds of SO_2 per hour on a 24-hour rolling average basis at Welsh Unit 2 semi-annually thereafter in accordance with General Provision #7.

17. During the first twelve months of operation of SN-01, or until the conditions of paragraph (1) have been fully satisfied, whichever is earlier, SO_2 emissions from SN-01 shall not exceed 480 pounds per hour on a 24-hour rolling average basis or a total of 1,900 tons per year as measured by the CEMS required by this permit. As stated in paragraph (3) below, if any condition in paragraph (1) is not met on the date specified, then, the emissions from SN-01 shall not exceed the pounds per hour levels in Table 1 on a 24-hour rolling average basis and the tons per year levels in Table 1 on a rolling 12-month basis until such time as the conditions in paragraph (1) are met.

18. Regardless of any provisions of this permit to the contrary, if SWEPCO has not obtained the permits as required by paragraph (1) for Unit 2 at the Welsh Plant from TCEQ; if SWEPCO fails to submit the required documentation to the Department and the United States Forest Service within the time frames specified in paragraph (1) above; or if the submissions of the required documentation demonstrate non-compliance with the emissions limitations stated in paragraph (1) above, emissions from SN-01 thereafter shall not exceed the pounds per hour levels in Table 1 on a 24-hour rolling average basis and the tons per year levels in Table 1 on a rolling 12-month basis until such time as the conditions in paragraph (1) are met.

Table 1:

Pollutant	Tons/Year	Lbs/hr
Sulfur dioxide	908	207
Nitrogen oxides	827	189
Particulate Matter (PM_{10}) Total	402	92

19. Within ninety (90) days after the first twelve months of operation of SN-01, or the effective date of the mitigation required by paragraph 1, whichever is earlier, the SWEPCO shall permanently surrender six (6) Acid Rain Program SO_2 allowances originally allocated to Welsh Unit 2 for each day from the date that SN-01 commences operation to the effective date of the mitigation required in paragraph 1 or the end of the 12-month period. The total Acid Rain Program SO_2 allowances permanently surrendered during the effective period shall not exceed 1,907 allowances. SWEPCO shall submit, in

accordance with the provisions of General Condition 7 of this permit, certification to the Department that Acid Rain Program allowance have been surrendered.

SECTION VIII: GENERAL PROVISIONS

1. Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the sole origin of and authority for the terms or conditions are not required under the Clean Air Act or any of its applicable requirements, and are not federally enforceable under the Clean Air Act. Arkansas Pollution Control & Ecology Commission Regulation 18 was adopted pursuant to the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.). Any terms or conditions included in this permit which specify and reference Arkansas Pollution Control & Ecology Commission Regulation 18 or the Arkansas Water and Air Pollution Control Act (A.C.A. §8-4-101 et seq.) as the origin of and authority for the terms or conditions are enforceable under this Arkansas statute. [40 CFR 70.6(b)(2)]

2. This permit shall be valid for a period of five (5) years beginning on the date this permit becomes effective and ending five (5) years later. [40 CFR 70.6(a)(2) and §26.701(B) of the Regulations of the Arkansas Operating Air Permit Program (Regulation 26), effective September 26, 2002]

3. The permittee must submit a complete application for permit renewal at least six (6) months before permit expiration. Permit expiration terminates the permittee's right to operate unless the permittee submitted a complete renewal application at least six (6) months before permit expiration. If the permittee submits a complete application, the existing permit will remain in effect until the Department takes final action on the renewal application. The Department will not necessarily notify the permittee when the permit renewal application is due. [Regulation 26, §26.406]

4. Where an applicable requirement of the Clean Air Act, as amended, 42 U.S.C. 7401, et seq. (Act) is more stringent than an applicable requirement of regulations promulgated under Title IV of the Act, the permit incorporates both provisions into the permit, and the Director or the Administrator can enforce both provisions. [40 CFR 70.6(a)(1)(ii) and Regulation 26, §26.701(A)(2)]

5. The permittee must maintain the following records of monitoring information as required by this permit. [40 CFR 70.6(a)(3)(ii)(A) and Regulation 26, §26.701(C)(2)]

   a. The date, place as defined in this permit, and time of sampling or measurements;
   b. The date(s) analyses performed;
   c. The company or entity performing the analyses;
   d. The analytical techniques or methods used;
   e. The results of such analyses; and
   f. The operating conditions existing at the time of sampling or measurement.

6. The permittee must retain the records of all required monitoring data and support information for at least five (5) years from the date of the monitoring sample,

measurement, report, or application. Support information includes all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, and copies of all reports required by this permit. [40 CFR 70.6(a)(3)(ii)(B) and Regulation 26, §26.701(C)(2)(b)]

7. The permittee must submit reports of all required monitoring every six (6) months. If permit establishes no other reporting period, the reporting period shall end on the last day of the anniversary month of the initial Title V permit. The report is due within thirty (30) days of the end of the reporting period. Although the reports are due every six months, each report shall contain a full year of data. The report must clearly identify all instances of deviations from permit requirements. A responsible official as defined in Regulation No. 26, §26.2 must certify all required reports. The permittee will send the reports to the address below: [40 C.F.R. 70.6(a)(3)(iii)(A) and Regulation 26, §26.701(C)(3)(a)]

   Arkansas Department of Environmental Quality
   Air Division
   ATTN: Compliance Inspector Supervisor
   Post Office Box 8913
   Little Rock, AR 72219

8. The permittee shall report to the Department all deviations from permit requirements, including those attributable to upset conditions as defined in the permit.

   a. For all upset conditions (as defined in Regulation19, § 19.601), the permittee will make an initial report to the Department by the next business day after the discovery of the occurrence. The initial report may be made by telephone and shall include:

      i. The facility name and location
      ii. The process unit or emission source deviating from the permit limit,
      iii. The permit limit, including the identification of pollutants, from which deviation occurs,
      iv. The date and time the deviation started,
      v. The duration of the deviation,
      vi. The average emissions during the deviation,
      vii. The probable cause of such deviations,
      viii. Any corrective actions or preventive measures taken or being taken to prevent such deviations in the future, and
      ix. The name of the person submitting the report.

   The permittee shall make a full report in writing to the Department within five (5) business days of discovery of the occurrence. The report must include, in addition to the information required by the initial report, a schedule of actions taken or planned to eliminate future occurrences and/or to minimize the amount the permit's limits were exceeded and to reduce the length of time the limits were exceeded. The permittee may submit a full report in writing (by facsimile, overnight courier, or other means) by the next business day after discovery of the occurrence, and the report will serve as both the initial report and full report.

b. For all deviations, the permittee shall report such events in semi-annual reporting and annual certifications required in this permit. This includes all upset conditions reported in 8a above. The semi-annual report must include all the information as required by the initial and full reports required in 8a.

[Regulation 19, §19.601 and §19.602, Regulation 26, §26.701(C) (3) (b), and 40 CFR 70.6(a) (3) (iii) (B)]

9. If any provision of the permit or the application thereof to any person or circumstance is held invalid, such invalidity will not affect other provisions or applications hereof which can be given effect without the invalid provision or application, and to this end, provisions of this Regulation are declared to be separable and severable. [40 CFR 70.6(a)(5), Regulation 26, §26.701(E), and A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

10. The permittee must comply with all conditions of this Part 70 permit. Any permit noncompliance with applicable requirements as defined in Regulation 26 constitutes a violation of the Clean Air Act, as amended, 42 U.S.C. §7401, et seq. and is grounds for enforcement action; for permit termination, revocation and reissuance, for permit modification; or for denial of a permit renewal application. [40 CFR 70.6(a)(6)(i) and Regulation 26, §26.701(F)(1)]

11. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity to maintain compliance with the conditions of this permit. [40 CFR 70.6(a)(6)(ii) and Regulation 26, §26.701(F)(2)]

12. The Department may modify, revoke, reopen and reissue the permit or terminate the permit for cause. The filing of a request by the permittee for a permit modification, revocation and reissuance, termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. [40 CFR 70.6(a)(6)(iii) and Regulation 26, §26.701(F)(3)]

13. This permit does not convey any property rights of any sort, or any exclusive privilege. [40 CFR 70.6(a)(6)(iv) and Regulation 26, §26.701(F)(4)]

14. The permittee must furnish to the Director, within the time specified by the Director, any information that the Director may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the permittee must also furnish to the Director copies of records required by the permit. For information the permittee claims confidentiality, the Department may require the permittee to furnish such records directly to the Director

along with a claim of confidentiality. [40 CFR 70.6(a)(6)(v) and Regulation 26, §26.701(F)(5)]

15. The permittee must pay all permit fees in accordance with the procedures established in Regulation 9. [40 CFR 70.6(a)(7) and Regulation 26, §26.701(G)]

16. No permit revision shall be required, under any approved economic incentives, marketable permits, emissions trading and other similar programs or processes for changes provided for elsewhere in this permit. [40 CFR 70.6(a)(8) and Regulation 26, §26.701(H)]

17. If the permit allows different operating scenarios, the permittee shall, contemporaneously with making a change from one operating scenario to another, record in a log at the permitted facility a record of the operational scenario. [40 CFR 70.6(a)(9)(i) and Regulation 26, §26.701(I)(1)]

18. The Administrator and citizens may enforce under the Act all terms and conditions in this permit, including any provisions designed to limit a source's potential to emit, unless the Department specifically designates terms and conditions of the permit as being federally unenforceable under the Act or under any of its applicable requirements. [40 CFR 70.6(b) and Regulation 26, §26.702(A) and (B)]

19. Any document (including reports) required by this permit must contain a certification by a responsible official as defined in Regulation 26, §26.2. [40 CFR 70.6(c)(1) and Regulation 26, §26.703(A)]

20. The permittee must allow an authorized representative of the Department, upon presentation of credentials, to perform the following: [40 CFR 70.6(c)(2) and Regulation 26, §26.703(B)]

    a. Enter upon the permittee's premises where the permitted source is located or emissions related activity is conducted, or where records must be kept under the conditions of this permit;
    b. Have access to and copy, at reasonable times, any records required under the conditions of this permit;
    c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and
    d. As authorized by the Act, sample or monitor at reasonable times substances or parameters for assuring compliance with this permit or applicable requirements.

21. The permittee shall submit a compliance certification with the terms and conditions contained in the permit, including emission limitations, standards, or work practices. The permittee must submit the compliance certification annually within 30 days following the last day of the anniversary month of the initial Title V permit. The permittee must also

submit the compliance certification to the Administrator as well as to the Department. All compliance certifications required by this permit must include the following: [40 CFR 70.6(c)(5) and Regulation 26, §26.703(E)(3)]

a. The identification of each term or condition of the permit that is the basis of the certification;
b. The compliance status;
c. Whether compliance was continuous or intermittent;
d. The method(s) used for determining the compliance status of the source, currently and over the reporting period established by the monitoring requirements of this permit;
e. and Such other facts as the Department may require elsewhere in this permit or by §114(a)(3) and §504(b) of the Act.

22. Nothing in this permit will alter or affect the following: [Regulation 26, §26.704(C)]

    a. The provisions of Section 303 of the Act (emergency orders), including the authority of the Administrator under that section;
    b. The liability of the permittee for any violation of applicable requirements prior to or at the time of permit issuance;
    c. The applicable requirements of the acid rain program, consistent with §408(a) of the Act or,
    d. The ability of EPA to obtain information from a source pursuant to §114 of the Act.

23. This permit authorizes only those pollutant emitting activities addressed in this permit. [A.C.A. §8-4-203 as referenced by A.C.A. §8-4-304 and §8-4-311]

Appendix A

40 CFR Part 60, Subpart Da – *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978*

Appendix B

40 CFR Part 60, Subpart Y – *Standards of Performance for Coal Preparation Plants*

Appendix C

40 CFR Part 60, Subpart IIII – *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines*

Appendix D

40 CFR Part 63, Subpart ZZZZ – *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*

Appendix E

Arkansas Continuous Emission Monitoring Systems Conditions

Appendix F

40 CFR Part 60, Subpart Db – *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*

CERTIFICATE OF SERVICE

I, Cynthia Hook, hereby certify that a copy of this permit has been mailed by first class mail to American Electric Power Service Corp. - Turk Power Plant, PO Box 660164, Dallas, TX, 75266-0164, on this 5th day of November, 2008.

C Hook

Cynthia Hook, AAII, Air Division