TECHNICAL SUPPORT DOCUMENT AND STATEMENT OF BASIS

FOR AIR QUALITY CONTROL PERMIT NO. 35043

ISSUED TO ARIZONA ELECTRIC POWER COOPERATIVE

APACHE GENERATING STATION

May 24, 2007

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I. INTRODUCTION

This Class I, Title V Permit is for the operation of the Apache Generating Station (Apache), located approximately 3 miles south of the town of Cochise, Cochise County, Arizona. Apache is owned and operated by Arizona Electric Power Cooperative, Inc. (AEPCO). The plant currently supplies electric power to six rural electric distribution systems serving portions of Arizona, California, and New Mexico. Additional wholesale customers include the City of Mesa, Arizona, and the Salt River Project.

A. Company Information

Facility Name:	Apache Generating Station
Mailing Address:	P.O. Box 670, Benson , AZ 85602
Facility Address:	3525 N. Hwy 191 South, Cochise, Cochise County, Arizona 85606

B. Background

The facility has been operating under a Class I Air Quality Permit (Permit No. 100109) issued by the Arizona Department of Environmental Quality (ADEQ) in July of 2000. In May of 2002, a significant revision (Permit No. 1001734) to the permit was issued by the Department for the installation and operation of a 44 megawatt (MW) gas turbine designated as Gas Turbine No. 4 (GT 4). This new generator was permitted to burn fuel oil as an emergency backup under a minor permit revision (No. 28077) that was issued for a modification to the coal handling facility.

The facility includes seven electric generating units (two coal/natural gas-fired steam electric units, a natural gas/fuel oil-fired steam electric, combined cycle unit, and four natural gas/fuel oil-fired turbines).

The total Plant generating capacity is 604 MW net.

C. Attainment Classification

The proposed source is located in an area that is designated attainment/unclassified for all criteria pollutants.

II. FACILITY DESCRIPTION

The maximum process rates based on base load operating conditions on an annual basis and operating hours of the generating units at Apache are summarized in Table 1. Please refer to the application for the maximum process rates based on peak load operating conditions on an hourly basis.

Table 1: Maximum Process Rates

Emission ID/Unit	Hours/y	MW	MW-hr/yr
001-Gas Turbine 1	8760	10.4	91,104
002-Gas Turbine 2	8760	19.8	173,448
003-Gas Turbine 3	8760	64.9	568,524
004-Gas Turbine 4	8760	44	385,440
005-Steam Unit 1	8760	75	657,000
006-Steam Unit 2	8760	195	1,708,200
007-Steam Unit 3	8760	195	1,708,200
TOTAL:		**604.1**	**5,291,916**

Note: The information in this table was provided by AEPCO in their application for a Class I Permit. The process rates and operating hours listed are for informational purposes only. In addition, this information should not be construed as establishing enforceable limitations of any form on Apache operations.

Data from the emission sources forms included in AEPCO's Class I Permit application shows that AEPCO has the potential to emit more than 100 tons per year (tpy) of all primary criteria pollutants (except lead) and more than 10 tpy of formaldehyde and nickel. This means that Apache is classified as a "major stationary source" pursuant to Clean Air Act Section 302.

A. Process Description

1. Units 2 and 3 (ST2 and ST3)

Steam Units 2 and 3 are Apache Station's base load generating units. They typically meet most of the power requirements of AEPCO's distribution cooperatives and other power contractors.

Steam Units 2 and 3 use natural gas igniters during start-up and when appropriate for flame stabilization, equipment testing, and load stabilization. On occasion AEPCO will use the igniters to provide an additional source of fuel to the boiler (up to 20% heat input), which is an alternate operating scenario for Steam Units 2 and 3 (i.e., co-firing natural gas and coal).

The primary fuel for Steam Units 2 and 3 is coal. When coal is burned, it must be pulverized into a fine powder before it is combusted in the boilers. This processing starts when coal is transferred from the coal handling system to the boiler crusher/dryers. The crusher/dryers reduce coal size and remove excess surface moisture. The smaller coal pieces are then sent to the ball tube mills where they are pulverized. Pulverized coal passes through the classifiers. Coal that is still too large is sent back to the ball tube mills for additional pulverizing, while adequately sized coal goes to the boiler for combustion.

In addition to producing radiant heat necessary to create steam to drive the steam turbines and generators, the combustion taking place in the boiler also creates hot exhaust gas. The exhaust gas from the boiler is first sent to the electrostatic precipitator (ESP) for removal of fly ash and unburned carbon from the gas stream. Bottom ash falling to the bottom of the furnace is removed with the help of hydro ejectors. Gas leaving the ESP enters the Sulfur Dioxide Absorption System (SDAS), where the sulfur dioxide is removed from the gas stream. The SDAS on each unit consists of two wet limestone scrubber modules. The system is designed for operation of only one module at a time; the second module is maintained as a standby unit. The scrubbed gas is then discharged to the atmosphere via a common stack for the two units.

2. Steam Unit 1 and Gas Turbine 1 (ST1/GT1)

Steam Unit 1 and Gas Turbine 1 are Apache Station's combined cycle unit. ST1/GT1 is the plant's primary backup unit. It is brought on line to meet increased load requirements during high demand periods or to supplement generation when ST2 or ST3, the larger generating units, are offline for repair or maintenance.

Steam Unit 1 and Gas Turbine 1 have the ability to be operated in combined cycle operation or simple cycle operation. Under combined cycle operation, exhaust from Gas Turbine 1 is used to provide intake air to the Steam Unit 1 wind box. This is done to increase the load output and efficiency of the system. In simple cycle operation, AEPCO provides combustion air to the boiler through the use of the unit's two forced draft fans.

Gas Turbines GT2 through GT4 are typically used during peak load demand. They also are available for backups when the larger generating units are offline for repair or maintenance.

3. The coal handling system at AEPCO, which includes crusher, sizing screens, silos, and loading and unloading systems, can transfer approximately 2,102,400 tons of coal to Steam Units 2 and 3 each year. This throughput is based on the maximum capacity of the reclaim operations, which is 240 tons per hour to the boiler.

4. The maximum annual process rate for the limestone handling operations at AEPCO, which produce limestone slurry for Apache's Sulfur Dioxide Absorption System (SDAS), is approximately 43,800 tons per year.

5. ST2 and ST3, in using coal for combustion, produce spent ash and organics not completely combusted. The Ash Handling System is primarily composed of bottom ash, which falls into two ash hoppers at the bottom of the furnace, and fly ash, which is captured in the hoppers of the economizer, electrostatic precipitator, and air heaters. Bottom ash and fly ash are pulled from the hoppers to holding

tanks. Sluice water is mixed with the fly ash where it too is then sent to the ash pit. The bottom ash and fly ash are then piped to the disposal ponds.

6. Alternative Operating Scenarios

Table 2: Operating Scenarios

Source	Primary	Alternative
Steam Unit 1	Natural Gas	#2 through #6 grades fuel oil Co-firing #2 - #6 grades fuel oil /used oil or used fuel oil Co-firing of natural gas and used oil or used oil fuel. Co-firing #2 through #6 grades fuel oil and natural gas
Steam Units 2 and 3	Coal	Natural gas Co-firing coal and natural gas Co-firing natural gas and used oil or used fuel oil. Co-firing coal and used oil or used fuel oil
Gas Turbines 1 and 2	Natural Gas	#2 fuel oil
Gas Turbine 3	Natural Gas	#2 fuel oil
Gas Turbine 4	Natural Gas	#2 fuel oil (emergency only)

Note: Used oil is to be combusted in either Steam Unit 1, 2, or 3 only; used oil is not to be combusted for more than 40 hours/year; and used oil when mixed with virgin fuel oil is not to exceed 5% of the total volume of fuel in any fuel storage tank.

B. Air Pollution Control Equipment

1. Steam Units 2 and 3

a. Electrostatic Precipitator (ESP)

The exhaust gas from the boiler is sent to the ESP for removal of fly ash and unburned carbon from the gas stream.

b. Sulfur Dioxide Absorption System (SDAS)

The exhaust gas from the ESP passes through the air heaters to the SDAS or "scrubber" for removal of sulfur dioxide (SO_2) from flue gasses.

2. GT4 Control Devices

a. GT4 is equipped with water injection and a Selective Catalytic Reduction (SCR) system to reduce NO_x emissions.

b. Carbon monoxide emissions are reduced by use of an oxidation catalyst, located upstream of the SCR.

3. Coal Preparation Plant

Coal handling processes to limit PM emissions include wet and dry dust suppression systems and a bag house.

4. Limestone Handling System

The limestone storage bin has a bag filter for dust suppression during initial transfer to the bin. Wetting bars are used between the weigh feeder and the ball mill chute.

Table 3: Pollution Control Equipment

Equipment ID	Description	Rated Capacity/Process Weight	Serial Number	Make/Model	Date of Commercial Operation/ Manufacture	Rated Efficiency
Electrostatic Precipitator	Hot Side ESP for ST2	1,104,000 ACFM@ 710F	75-342	Universal Oil Products	1976-1977	99.56%
Sulfur Dioxide Absorption System (SDAS)	Wet Limestone scrubber for ST2	363,000 ACFM normal operation	N/A[1]	Research Cottrell	1976	85% to 20% of maximum unit rating
Electrostatic Precipitator	Hot Side ESP for ST3	1,104,000 ACFM@ 710F	75-342	Universal Oil Products	1976-1977	99.56%
Sulfur Dioxide Absorption System (SDAS)	Wet Limestone scrubber for ST3	363,000 ACFM normal operation	N/A[1]	Research Cottrell	1976	85% to 20% of maximum unit rating
Coal Dust Collection System	Fabric filter serving Coal Silos 2A, 2B, and 2C, and conveyors 4A, 4B, and 5-2 and 5-3	28,000 ACFM	325	Air-Cure Incorporated /RF Dust collector/376 RF10	1996	
Coal Dust Suppression System	Dry Fogging systems at Railcar unloading, transfer points between Conveyor #1 and Conveyor #2 stack-out tube, transfer point between Conveyor #3 and Conveyors #4A and	N/A[1]	N/A[1]	N/A[1]	N/A[1]	N/A[1]

Equipment ID	Description	Rated Capacity/Process Weight	Serial Number	Make/Model	Date of Commercial Operation/ Manufacture	Rated Efficiency
	4b and the three rotary plows					
	Wet Dust suppression at screen feeders during screening and at the entrance and exit of the crusher during crushing	N/A[1]	N/A[1]	N/A[1]	N/A[1]	N/A[1]
Limestone Silo Bag Filter	Bag Filter on Limestone Silo	575 ACFM	12-52-8117	Flex Kleen/ Research Cottrell/58-BV16-11	1977	N/A[1]
GT-4 Pollution Controls	Water Injection and SCR for NO_x reduction	N/A[1]	SCR-1	Engelhard VNX Vanadiatitania	2002	N/A[1]
	Oxidation Catalyst for CO reduction	N/A	CO-1	Engelhard Camet Co.	2002	N/A

Note 1: N/A is Not Applicable

III. COMPLIANCE HISTORY

A. Testing & Inspections

Inspections are being regularly conducted on this source to ensure compliance with the permit conditions. Table 4 summarizes some of the recent inspections that have been conducted on the source and the results of the inspections.

Table 4: INSPECTION REPORTS

Inspection ID:	Inspection Date	Type of Inspection	Results
66067	August 16-18, 2005	Performance Test of GT-1 and GT-4	RATA's for NO_x were performed on each unit. No violations observed.
61066	April 20, 2005	RTUS	No violations observed.
57644	November 16-17, 2004	Performance Test Units 2 & 3	Compliance tests for PM, SO_x, and NO_x were performed on units 2 and 3. The tests indicated compliance of the source with the applicable regulations.
51648	July 13-14, 2004	Performance Test of GT-4	RATA for NO_x, CO_2 and CO. No violations were observed.
50021	June 8, 2004	RUTS Level 2	No violations observed.
44585	January 14-15, 2004	Performance Test	Compliance tests for PM, SO_x, and NO_x were performed on units 2 and 3. RATA's were also conducted on the monitoring systems of each unit.
42661	November 13, 2003	Level 1	The purpose of the inspection was to review excess emissions from

Inspection ID:	Inspection Date	Type of Inspection	Results
		Unannounced	unit 3 on October 27, 2003. At low unit load, stack temperature was also low. The ambient humidity was high causing the dew point to match stack temperature causing vapor to condense causing less light to be returned to the detector. As a result opacity reads higher in the stack. Other recent scenarios were also reviewed. An NOV was recommended.
40513	October 15, 2003	Level 2 Unannounced	Investigation of a complaint that periodic brown streaks were being emitted by the main stack. No violations observed. During pre-inspection, Mr. Andrew pointed out that no opacity limit was listed for GT-4.
40238	June 2-3, 2003	Performance Test Units 2 & 3	Compliance tests for PM, SO_x, and NO_x were performed on units 2 and 3. The tests indicated compliance of the source with the applicable regulations.
32587	October 22-25, 2002	Performance Test of GT-4	Compliance tests for PM, CO and NO_x while firing Fuel Oil and Natural Gas. RATA was also completed.

B. Excess Emissions

Units 2 and 3 have reported excess visible emissions in the past two years (2006 and 2005) over one hundred and seventy-five times.

The primary cause of excess visible emissions reported (50 events) occurred when removing a scrubber module from service. The changing air flow patterns upset fly ash deposited in the scrubber bypass duct.

A secondary source of excess visible emissions reported (23) was a repeat of the in-stack condensation problem reported in the previous permit renewal. The in-stack condensation occurs because of the wetness of the flue gas exiting the wet limestone scrubber.

Other causes include start-up/load ramping, shutdown, soot blowing, and air pollution control equipment malfunction.

Of the total hours of excess opacity for unit 2 (65.6 hrs) in 2005 and 2006, 20.7 hrs were attributed to startup/shutdown/malfunction. The removal of a scrubber module from service, re-entraining the fly ash deposited in the scrubber bypass duct contributed 23.5 hours. Less than 1 hour was attributed to the moisture condensation in the stack. The remaining 21 hours were spread over a number of sources.

Steam unit 3 recorded a total of 306.1 hours of excess opacity. Startup/shutdown/malfunction consumed 144.7 hrs. Moisture condensation in the stack attributed 43.3 hrs. Removing a scrubber module from service, with the resulting air flow patterns, upsetting fly ash deposited in the scrubber bypass duct, accounted for another 27.3 hours. The remaining 91 hours were spread over a number of sources.

Units 2 and 3 have no reported case of excess emissions of NOx in the last two years (2005 and 2006). Unit 3 reported excess emissions of SO_2 (0.86 lb/MMBtu) on March 1, 2006. The cause of the emissions was a faulty packing pump discharge line. The other scrubber module was brought into operation till the problem was resolved.

Table 5: EXCESS EMISSION REPORTS

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1611	4/26/2006	1	6	3	21.27	Operator took ESP out of energy conservation mode and biased the ID fans to enable particulate removal.
1610	4/27/2006	5.5	3	3	0.23	Operator removed tower from service for maintenance on 3B packing pump discharge
1609	4/21/2006	0.4	2	3	20.70	Excess opacity during soot blowing. Maintenance on soot blower was in progress in progress.
1608	4/14/2006	0.1	1	3	35.70	In-stack condensation caused by both SO2 modules operating and ductwork drain problems.
1607	4/14/2006	0.6	4	3	21.35	Switching scrubber modules upset re-entrained fly ash in scrubber bypass duct.

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1606	4/15/2006	3.5	3	3	21.13	Switching scrubber modules upset re-entrained fly ash in scrubber bypass duct.
1605	4/14/2006	0.1	1		35.70	
1604	4/14/2006	0.1	1		35.70	
1597	4/16/2006	0.5	3	3	21.23	In-stack condensation caused by both SO2 modules operating and ductwork drain problems.
15.96	4/13/2006	1.8	3	3	21.03	Switching scrubber modules upset re-entrained fly ash in scrubber bypass duct.
1595	4/12/2006	0.6	2	3		In-stack condensation caused by both SO2 modules operating and ductwork drain problems.
1545	3/29/2006	0.3	2	3	21.15	Removing scrubber module from service to swap quencher pumps upset re-entrained fly ash in scrubber bypass duct.
1542	3/15/2006	1.3	11	3	39.89	Boiler Trip due to seal air fan damper malfunction
1541	3/17/206	8	2	2	38.55	Switching scrubber modules upset re-entrained fly ash in scrubber bypass duct.
1540	3/13/2006	0.2	2	2	41.70	2A Scrubber tower tripped due to quencher pump failure
1539	3/10/2006	0.5	4	3	40.63	UNIT STARTUP
1538	3/10/2006	0.5	3	3	24.50	UNIT STARTUP
1537	3/10/2006	0.5	4	3	31.68	UNIT STARTUP
1536	3/10/2006	7.5	2	3	30.30	UNIT STARTUP

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1535	3/11/2006	0.3	2	3	20.80	Excessive moisture carryover from scrubbers
1534	3/11/2006	0.2	1	3	20.50	Excessive moisture carryover from scrubbers
1533	3/9/2006	11.9	118	3	44.52	UNIT SHUTDOWN
1532	3/9/2006	7.1	2	3	30.35	UNIT SHUTDOWN
1531	3/7/2006	7.1	10	3	21.29	In-stack condensation caused by excess carryover from scrubbers
1530	3/7/2006	7.7	2	3	20.55	In-stack condensation caused by excess carryover from scrubbers
1529	3/8/2006	2.6	23	3	22.45	In-stack condensation caused by excess carryover from scrubbers
1528	3/8/2006	11.9	64	3	44.25	Boiler Trip due to loss of flame from boiler tube failure
1527	3/7/2006	0.3	2	2	25.75	Switching scrubber modules upset re-entrained fly ash in scrubber bypass duct.
1526	3/3/2006	0.3	1	3	21.10	In-stack condensation caused by excess carryover from scrubbers
1525	3/4/2006	0.8	7	3	31.80	UNIT SHUTDOWN
1524	3/5/2006	5.3	42	3	34.94	UNIT STARTUP
1523	3/5/2006	0.8	2	3	24.20	UNIT STARTUP initial fires, fans and load ramp
1522	3/1/2006	0.3	1	3	21.50	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1521	3/1/2006	1	1	3	SO_2 0.86 lb/MMBtu	Emergency repairs to a packing pump discharge line
1520	2/27/2006	0.1	1	2	43.50	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1519	2/24/2006	0.2	1	3	20.70	In-stack condensation caused by excess carryover from scrubbers. Duct opacity monitor upstream of scrubber indicated lower opacity than at stack
1518	2/21/2006	0.2	1	3	20.70	Soot blowing
1517	2/19/2006	0.5	1	3	27.30	UNIT STARTUP
1516	2/18/2006	0.4	3	3	21.03	UNIT SHUTDOWN
1515	2/18/2006	3.6	26	3	23.26	UNIT SHUTDOWN
1514	2/19/2006	7.1	32	3	30.13	UNIT SHUTDOWN
1513	2/19/2006	0.3	3	3	23.77	UNIT STARTUP initial fires, fans and load ramp
1512	2/19/2006	0.2	2	3	31.15	UNIT STARTUP
1511	2/17/2006	0.2	1	3	29.20	Fuel/Air imbalance
1487	1/19/2006	0.1	1	2	27.50	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1486	1/10/2006	0.4	3	3	51.00	Load ramping pulverizer startup and fan start

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1485	1/10/2006	5	6	3	24.95	Soot Blowing! Operator took ESP out of energy conservation mode and biased fans for PM removal
1484	1/9/2006	2.1	13	3	51.62	UNIT STARTUP
1483	1/7/2006	4	40	3	47.44	UNIT SHUTDOWN
1482	1/7/2006	6.2	61	3	61.68	UNIT SHUTDOWN
1481	1/5/2006	0.3	3	3	63.47	Boiler Trip due to negative pressure, cause unknown
1480	1/5/2006	0.2	2	3	36.60	UNIT STARTUP
1479	1/5/2006	4.8	20	3	33.97	UNIT STARTUP initial fires, fans and load ramp

2005

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1478	12/29/2005	5.2	5	3	23.40	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct. ESP performance contributing to problem
1477	12/29/2005	9.2	7	3	21.54	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct. ESP performance contributing to problem
1476	12/25/2005	0.3	2	3	21.15	Combustion upset from mill control problems
1475	12/26/2005	2.1	3	3	20.90	Load ramping pulverizer startup and fan start
1474	12/27/2005	0.1	1	3	20.80	Removing scrubber module from service to verify condensate in stack, upset re-entrained fly ash in scrubber bypass duct.
1473	12/27/2005	0.2	1	3	20.80	Load ramping pulverizer startup and fan start
1472	12/17/2005	3.2	1	3	20.60	Air flow upset undetermined origin
1471	12/16/2005	6.1	1	3	20.60	In-stack condensation caused by excess carryover from both scrubbers operating simultaneously.
1470	12/19/2005	0.8	1	3	22.00	In-stack condensation caused by excess carryover from both scrubbers operating simultaneously.
1469	12/19/2005	1	4	3	21.55	In-stack condensation caused by excess carryover from both scrubbers operating simultaneously.
1468	12/19/2005	1	9	3	21.66	In-stack condensation caused by excess carryover from both scrubbers operating simultaneously.

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1467	12/18/2005	6.1	24	3	21.14	In-stack condensation caused by excess carryover from both scrubbers operating simultaneously.
1466	12/19/2005	1	9	3	21.74	In-stack condensation caused by excess carryover from both scrubbers operating simultaneously.
1465	12/19/2005	1	9	3	21.40	In-stack condensation caused by excess carryover from both scrubbers operating simultaneously.
1464	12/19/2005	1.6	3	3	20.60	In-stack condensation caused by excess carryover from both scrubbers operating simultaneously.
1463	12/20/2005	0.8	4	3	22.90	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1482	12/20/2005	0.2	2	3	35.00	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1461	12/15/2005	0.6	3	3	22.70	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1460	12/14/2005	0.3	1	3	30.50	Soot Blowing
1459	12/6/2005	0.8	1	3	28.50	ESP power level problems
1458	12/6/2005	7.4	7	3	23.47	On-line mechanical ESP cleaning.
1457	12/7/2005	3.6	6	3	21.20	On-line mechanical ESP cleaning.
1456	12/7/2005	2.7	2	3	25.75	Switching scrubber modules upset re-entrained fly ash in scrubber bypass duct.
1455	12/5/2005	1	9	3	31.88	Condensation caused by excess carryover from dual scrubber operation Low unit load and ESP performance issues

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1453	12/4/2005	3.9	32	3	34.38	UNIT SHUTDOWN
1452	12/4/2005	11.2	94	3	44.62	UNIT SHUTDOWN
1451	12/4/2005	10.8	48	3	33.39	UNIT SHUTDOWN
1450	12/5/2005	1	8	3	31.01	UNIT STARTUP
1448	12/5/2005	0.6	5	3	22.98	UNIT STARTUP
1447	12/8/2005	0.7	6	3	26.32	UNIT STARTUP
1446	12/5/2005	0.9	5	3	23.42	UNIT STARTUP
1445	12/5/2005	3.9	5	3	23.42	In-stack condensation caused by excess carryover from both scrubbers operating simultaneously. Low unit load and ESP performance issues
1444	12/5/2005	0.1	1	3	21.00	ESP control problems
1443	12/6/2005	0.1	1	3	27.60	ESP control problems
1442	11/28/2005					
1441	11/27/2005	2.1	3	2	38.27	UNIT STARTUP
1440	11/23/2005	0.1	1	2	28.70	UNIT STARTUP
1439	11/22/2005	0.6	5	3	29.22	Removing scrubber module from service upset re-entrained fly ash in scrubber.

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1438	11/15/2005	0.3	2	3	21.50	2A Scrubber tower tripping while swapping quencher pumps to replace bad bearing
1437	1/15/2005	0.7	6	2	32.93	UNIT STARTUP cleaning boiler
1436	11/12/2005	0.4	3	3	21.83	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1435	11/13/2005	2.4	3	2	33.90	UNIT STARTUP cleaning boiler
1434	11/9/2005	0.2	1	3	40.40	2A Scrubber tower tripped when quencher pumps tripped and backup failed
1433	11/3/2005	2.5	22	3	21.47	Measure error caused by a build-up of material on the optical surfaces of the transmissometeres
1432	11/5/2005	5.5	40	3	21.02	Measure error caused by a build-up of material on the optical surfaces of the transmissometeres
1431	11/5/2005	0.1	1	3	20.50	Measure error caused by a build-up of material on the optical surfaces of the transmissometer
1429	11/2/2005	9.1	51	3	21.52	Measure error caused by a build-up of material on the optical surfaces of the transmissometer
1428	11/2/2005	2.5	22	3	25.20	Measure error caused by a build-up of material on the optical surfaces of the transmissometer
1427	11/1/2005	0.1	1	3	31.40	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1426	11/1/2005	0.2	1	3	27.50	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1425	11/1/2005	4.9	44	3	23.28	Measure error caused by a build-up of material on the optical surfaces of the transmissometer

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1424	10/11/2005	1.4	7	3	25.09	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1423	10/8/2005	0.3	3	3	33.17	Loss of power to several transformer/rectifiers on ESP
1422	10/15/2005	3.9	39	2	64.86	UNIT SHUTDOWN for unit overhaul
1421	10/15/2006	5	10.6	92	53.13	UNIT SHUTDOWN for unit overhaul
1420	10/12/2005	0.2	1	2	20.60	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1419	10/4/2005	0.1	1	2	22.20	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1418	10/3/2005	0.4	2	2	23.00	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1417	9/11/2005	14.2	71	3	33.46	UNIT SHUTDOWN for unit maintenance
1416	9/13/2005	0.1	1	2	22.60	Malfunctioning combustion controls caused natural gas igniters to trip
1415	9/13/2005	0.1	1	2	22.70	Load ramping pulverize startup and fan start
1414	9/13/2005	0.2	2	2	37.15	Load ramping pulverizer startup and fan start
1413	9/14/2005	1.1	4	2	25.38	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1412	9/14/2005	3.1	2	2	23.00	Loss of power to several transformer/rectifiers on ESP
1411	9/15/2005	0.7	5	2	30.16	Soot blowing

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1410	9/15/2005	0.1	1	2	30.70	Soot blowing
1409	9/15/2005	0.1	1	2	27.60	Soot blowing
1407	9/14/2005	0.1	1	3	31.50	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1406	9/15/2005	3.1	4	2	26.05	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1405	9/13/2005	0.4	4	2	27.20	UNIT STARTUP
1404	9/11/2005	11.9	10	3	31.29	UNIT SHUTDOWN for unit maintenance. Fans running to cool boiler
1403	9/11/2005	10.9	77	3	31.24	UNIT SHUTDOWN for unit maintenance. Fans running to cool boiler
1402	9/10/2005	9.1	44	3	28.65	UNIT SHUTDOWN for unit maintenance
1401	9/12/2005	1.4	7	2	21.93	UNIT SHUTDOWN for unit maintenance. Fans running to cool boiler
1400	9/12/2005	3.4	16	2	31.75	UNIT SHUTDOWN for unit maintenance
1399	9/7/2005	5	10	2	24.53	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1398	9/7/2005	0.3	2	3	33.50	Scrubber tower tripped while switching quencher pumps
1397	9/6/2005	0.4	3	2	34.37	Removing scrubber module from service upset re-entrained fly ash in scrubber bypass duct.
1396	8/16/2005	7.3	3	3	23.60	Operator took ESP out of energy conservation mode to enable more effective particulate removal.

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1395	8/15/2005	0.7	1	3	24.30	Emission occurred during load ramping. Operator took ESP out of energy conservation mode to enable more effective particulate removal.
1394	8/14/2005	0.7	5	3	22.98	Switching scrubber modules upset re-entrained fly ash in scrubber bypass duct.
1393	8/12/2005	0.3	3	2	49.17	Unit Trip and Startup following an electrical malfunction and transformer failure
1392	8/12/2005	0.3	2	2	29.25	Unit Startup Operations
1391	8/10/2005	0.2	2	2	32.80	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1390	8/4/2005	0.4	2	2	25.70	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1389	7/31/2005	0.3	2	3	20.85	Emergency load ramping
1385	7/29/2005	0.1	1	2	38.20	Excess occurred during soot blowing. ESP precipitator in conservation mode
1384	7/27/2005	0.2	2	2	29.30	In-stack condensation caused by rain water entrainment during heavy rain. Duct work repaired.
1383	7/21/2005	0.1	1	2	36.40	Lost SDAS due to electrical phase imbalance. Switch to an alternate breaker.
1382	7/22/2005	0.2	2	2	42.25	Scrubber module tripped due to packing pump malfunction.
1381	7/22/2005	0.2	1	3	27.70	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1379	7/12/2005	0.2	2	3	30.30	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1378	7/13/2005	0.7	5	2	25.22	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1377	7/5/2005	0.2	1	3	22.50	Scrubber tower out of service, while conducting soot blowing operations.
1376	7/3/2005	9.6	3	3	24.00	Excess occurred during soot blowing. ESP was in conservation mode.
1375	7/1/2005	0.1	1	2	31.50	Placing a scrubber back in service, resulting in a gas flow upset which re-entrained fly ash in scrubber ductwork.
1374	7/1/2005	0.2	2	2	41.60	Scrubber module failed due to quencher pump trip.
1373	6/27/2005	0.4	3	2	28.40	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1372	6/22/2005	0.1	1	2	0.22	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1370	6/22/2005	0.2	2	2	22.50	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1369	6/22/2005	0.3	3	2	22.10	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1368	6/22/2005	0.3	2	2	23.70	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1367	6/22/2005	0.1	1	2	21.00	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1365	6/22/2005	0.2	2	2	24.25	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1364	6/22/2005	0.1	1	2	27.50	Scrubber module removed from service upset re-entrained fly ash in scrubber

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
						bypass duct.
1362	6/22/2005	0.1	1	2	24.00	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1360	6/22/2005	0.2	2	2	31.65	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1359	6/22/2005	0.1	1	2	21.70	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1358	6/22/2005	0.1	1	2	29.40	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1356	6/22/2005	0.1	1	2	27.50	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct
1351	6/20/2005	9.1	1	2	29.50	Blowing Air Pre-Heater
1349	6/20/2005	0.1	1	2	22.10	2A Tower out of service.
1348	6/21/2005	0.2	1	2	23.90	2A Tower out of service.
1345	6/20/2005	0.1	1	2	36.30	2A Tower out of service.
1343	6/18/2005	0.3	3	2	36.30	Unit Startup
1342	6/18/2005	0.4	2	2	28.75	Unit Startup
1335	6/15/2005	0.9	1	2	28.50	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct

Record ID:	Date	Duration (Hours)	Number this occurrence	Unit Affected	Emission violation for this emission point	Results
1334	6/15/2005	0.4	1	2	20.90	Excess Emission occurred during load ramping. Operator took ESP out of energy conservation mode to enable more effective particulate removal.
1332	6/7/2005	0.2	1	3	28.10	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct
1331	6/3/2005	0.2	1	2	22.20	Scrubber tower out of service, while conducting soot blowing operations.
1330	6/3/2005	0.2	1	2	24.40	On-line ESP mechanical cleaning.
1329	6/2/2005	1	5	3	28.52	Unit Trip due to operator error.
1328	6/2/2005	0.3	2	3	22.70	Recovery from boiler trip. Load ramping, starting pulverize and associated fans. Operator took ESP out of energy conservation mode.
1327	6/2/2005	0.2	1	3	29.30	Unit Trip due to operator error.
1326	5/27/2005	0.1	1	3	34.00	In-stack condensation caused by rain water entrainment during heavy rain. Duct work repaired.
1325	5/12/2005	0.2	1	2	29.20	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct
1324	5/11/2005	0.2	1	3	30.40	Scrubber module removed from service upset re-entrained fly ash in scrubber bypass duct.
1323	5/6/2005	1	4	3	29.20	Combustion upset. ID fans biased to maximize particulate collection.
1321	5/1/2005	2.2	15	3	23.26	In- stack condensation caused by low unit load, ambient conditions. Duct monitors indicate low particulate opacity

IV. EMISSIONS

The Apache plant has the capability of operating under different scenarios as outlined in Section II above. Typical operating parameters of the turbines and the steam units are given in Table 6. Table 8 summarizes the potential to emit (PTE), allowable emissions, test results, and the emissions inventory (EI) for these units. The emission factors used to calculate the potential to emit are from AP-42 (1/95 ed.). AEPCO, in the permit application, provided the emission factors for the gas turbines and the steam generators from EPA publication EPA 450/4-90-003. These numbers do not vary significantly from AP-42 numbers. The characteristics of fuel oil #6 were used to conservatively estimate the emissions from used oil burning due to the lack of availability of emissions calculation factors for used oil burning. Although calculations have been shown here only for the worst-case scenario of burning fuel oil #6 in steam unit 1 and turbine #3, the steam unit and the turbine have the capability to burn fuel oil #2 through #6. The allowable emissions are calculated using the standards under 40 CFR 60, Subpart D, A.A.C. R18-2-703, and A.A.C. R18-2-719. Detailed emissions calculations, are contained in the attachment to this technical support document.

Table 6 Typical Operating Parameters

Description	Steam Unit 1	Steam Units 2 and 3	Gas Turbine 1	Gas Turbine 2	Gas Turbine 3	Gas Turbine 4
Rated generating capacity (MW)	Gas: 75 Oil: 75 Coal: N/A	Gas: 195 Oil: N/A Coal: 195	Gas: 10.4 Oil: 10.4	Gas: 19.8 Oil: 19.4	Gas: 64.9 Oil: 63.4	Gas: 44 Oil: 44
Maximum generating capacity (MW)	Gas: 85 Oil: 85 Coal: N/A	Gas: 210 Oil: N/A Coal: 210	Gas: 13.2 Oil: 13.2	Gas: 26.1 Oil: 25.6	Gas: 72.3 Oil: 70.7	Gas: 44 Oil: 44
Net heat rate at Rated capacity (Btu/KWh)	Gas: 11350 Oil: 12900 Coal: N/A	Gas: 10000 Oil: N/A Coal: 9800	Gas: 19100 Oil: 19400	Gas: 19100 Oil: 14200	Gas: 13500 Oil: 13500	Gas: 9075 Oil: 9245
Net heat rate at maximum capacity (Btu/KWh)	Gas: 11200 Oil: 14150 Coal: N/A	Gas: 9950 Oil: N/A Coal: 9700	Gas: 16700 Oil: 16600	Gas: 14300 Oil: 13200	Gas: 12100 Oil: 12100	N/A
Heating value of natural gas (Btu/scf)	1032	1032	1032	1032	1032	1020
Heating value of fuel oil (Btu/gal)	135000 (#2) 150000 (#6)	N/A	135000 (#2)	135000 (#2)	135000 (#2) 150000 (#6)	135000 (#2)
Heating value of coal (Btu/lb)	N/A	12000	N/A	N/A	N/A	N/A
Sulfur content of fuel oil	0.05% (#2) 0.75% (#6)	N/A	0.05% (#2)	0.05% (#2)	0.05% (#2) 0.75% (#6)	0.05% (#2)
Sulfur content of coal	N/A	0.26 - 1.0%	N/A	N/A	N/A	N/A

Note: The parameters listed in this table are based on the PTE calculations AEPCO provided to support their application for a Class I Permit. In addition, this information should not be construed as establishing enforceable limitations of any form on Apache operations.

Table 7 Heat Rate by Unit

	GT-1	GT-2	GT-3	GT-4	Steam Unit 1	Steam Unit 2	Steam Unit 3
Rated Capacity (MW)	13	26	72	44	85	210	210
Heat Rate at Rated Capacity (Btu/Kw-hr)	19,100	19,100	13,500	9075	11,350	10,000	10,000
Max Potential Heat Input (MMBtu/hr)	252	499	976	369	965	2,100	2,100
Max Potential Fuel Use (Mcf/hr)	0.247	0.489	0.957	0.389	0.946	2.059	2.059
Max Potential Fuel Use (1000 gal/hr)				2.63			

Note: Values based on combustion of natural gas, with the exception of values for Steam Units 2 and 3 for coal combustion.

Table 8A. Turbine Generator Emissions PTE Emissions (In Tons per year))

Criteria Pollutant	GT 1		GT 2		GT 3		GT 4
Fuel	NG	Oil	NG	Oil	NG	Oil	Comb.[1]
Particulate Matter	229.62	8.77	343.29	13.74	752.23	41.27	14.88
PM-10	1.40	8.77	2.36	13.74	6.54	41.27	14.88
SO2	2.50	36.90	4.22	57.81	11.69	173.70	1.07
NOx	286.70	643.03	483.66	1007.39	1341.43	3026.82	39.57
CO	60.00	2.41	101.69	3.78	282.04	11.35	36.78
VOC	1.54	0.30	2.60	0.47	7.22	1.41	5.81
Lead	ND	0.01	ND	0.02	ND	0.05	ND
NH4	N/A	N/A	N/A	N/A	N/A	N/A	20.78
HAPS	0.75	0.93	1.27	1.46	3.52	4.38	2.00

1. Combination of NG and #2 fuel oil (600 hrs/yr)

Table 8B. Steam Unit Emissions PTE Emissions (In Tons per year)

Criteria Pollutant	Steam Unit 1	Steam Unit 2		Steam Unit 3		Engine [1]
Fuel	**NG**	**NG**	**Coal**	**NG**	**Coal**	**#2 Fuel Oil**
Particulate Matter	792.22	848.52	827.20	848.52	827.20	4.64
PM-10	6.85	15.81	193.20	15.81	193.20	4.64
SO2	2.16	4.99	6617.60	4.99	6617.60	4.34
NOx	1010.00	1697.04	4136.00	1697.04	4136.00	66.06
CO	301.69	332.75	209.90	332.75	209.90	14.23
VOC	19.84	45.75	25.20	45.75	25.20	5.24
Lead	0.00	0.00	0.08	0.00	0.08	N/T
NH4	N/A	N/A	N/A	N/A	N/A	N/A
HAPS	6.80	15.72	278.35	15.73	561.43	0.09

1. GT1 Diesel Starting Engine

Table 8C. Fugitive Emissions (In Tons per year)

Source Description	Particulate Matter	PM10
Railcar Unloading	21.00	11.00
Sizing Screens	168.00	84.00
Crusher	21.00	11.00
Coal Belt Transfer Pts.	1,682.00	841.00
#3 Belt Exhaust Fan	210.00	105.00
Reclaim Transfer Points	1,682.00	841.00
4a and 4b Belt Scrapers	79.00	39.00
Coal Silos	1,261.00	631.00
Limestone Operations	17.50	3.90
Limestone Handling	52.60	11.80

V. APPLICABLE REGULATIONS

The Permittee has identified the applicable regulations that apply to each unit in its permit application. Table 9 summarizes the findings of the Department with respect to the regulations that apply to each emissions source. Installation Permit and other previous permit conditions are discussed under Section VI of this technical review document.

Table 9: Applicable Regulations Verification

Unit ID	Date of Manufacture	Control Device	Applicable Regulations	Verification
Steam Unit 1	8/62	None	A.A.C. R18-2-702.B A.A.C. R18-2-703.A A.A.C. R18-2-703.B A.A.C. R18-2-703.C.1 A.A.C. R18-2-703.E.1 A.A.C. R18-2-703.H A.A.C. R18-2-703.J A.A.C. R18-2-703.K	Standards of Performance for Existing Fossil-fuel Fired Steam Generators and General Fuel-burning Equipment
			40 CFR 72	Acid Rain Program
			40 CFR 73	Sulfur Dioxide Allowance Program
			40 CFR 75	Continuous Emission Monitoring Requirements
Steam Units 2 & 3	8/28/74 for the steam units and the control equipment	2 ESPs and 2 SDAS	40 CFR 60.42(a) 40 CFR 60.43 (a) A.A.C. R18-2-903.1, A.A.C. R18-2-903.2 40 CFR 60.Subpart D	Standards of Performance for Fossil-fuel Fired Steam Generators
			40 CFR 72	Acid Rain Program
			40 CFR 73	Sulfur Dioxide Allowance Program
			40 CFR 75	Continuous Emission Monitoring Requirements
Gas Turbines 1, 2, and 3	#1: 1/61 #2: 8/71 #3: 7/73	None	A.A.C. R18-2-719.A	Standards of Performance for Existing Stationary Rotating Machinery

Unit ID	Date of Manufacture	Control Device	Applicable Regulations	Verification
Gas Turbine 4	2002	Water injection and SCR for NO_x Oxidation Catalyst for CO	40CFR 60, Subpart GG	Standards of Performance for Stationary Gas Turbines
			40 CFR 75	Continuous Emission Monitoring Requirements
			40 CFR 72	Acid Rain Program
			40 CFR 73	Sulfur Dioxide Allowance Program
Coal Preparation Plant	3/21/75	Spray bars, dry fogging and baghouse on silos	40 CFR 60 Subpart Y A.A.C. R18-2-730 A.A.C. R18-2-702.B Installation Permit 24014	Normal Operation is subject to Standards of Performance for Existing Coal Preparation Plants (A.A.C. R18-2-730) Alternate Operation is subject to Standards of Performance for Coal Preparation Plants (40 CFR 60 Subpart Y)
Limestone Preparation Plant	3/21/75	Bag filter on limestone storage bin	A.A.C. R18-2-702.B A.A.C. R18-2-722 Installation Permit 24014	Standards of Performance for Existing Gravel or Crushed Stone Processing Plants
Cooling Towers 1, 2, and 3	9/25/74		A.A.C. R18-2-702.B A.A.C. R18-2-730	Standards of Performance for Unclassified Sources
Fugitive . Dust Sources	Not Applicable	Control Measures	A.A.C. R18-2-602 R18-2-604.A R18-2-604.B R18-2-605 R18-2-606 R18-2-607 R18-2-612	The regulations listed are applicable to fugitive dust sources.
Abrasive Blasting	Not Applicable	Wet blasting, enclosure, or equivalent (approved by Director)	A.A.C. R18-2-726 R18-2-702.B	Relevant requirements applicable to abrasive blasting

Unit ID	Date of Manufacture	Control Device	Applicable Regulations	Verification
Spray Painting	Not Applicable	Control measures that attain 96% efficiency	A.A.C. R18-2-727	Relevant requirements applicable to spray painting
Mobile Sources	Not Applicable	Control Measures	A.A.C. R18-2-801 R18-2-802.A R18-2-804	These regulations are applicable to all mobile sources.
Demolition/ Renovation	Not Applicable	None	A.A.C. R18-2-1101.A.8 (NESHAP for asbestos)	Relevant requirements applicable to demolition and renovation operations

VI. PREVIOUS PERMITS

A. Previous Permits

Table 10: Previous Permits

Date Permit Issued	Permit No.	Application Basis
July 6, 2000	1000109	Previous Title V permit
May 3, 2002	1001734	Significant revision adding GT4
March 26, 2003	28077	Minor revision to allow GT4 to use diesel fuel as

B. Previous permits that have been issued to this source:

CLASS I, TITLE V OPERATING PERMIT NO. 1000109

OP #1000109, References	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att. A.	×				General provisions - revised to represent most recent language
Att. B.I.A.1		×			Opacity Standard of 20% and 27% for one six-minute period per hour for the boilers of Units 2 and 3
Att. B.I.A.1.a	×				Startup definition has been revised to be more consistent with the NSPS
Att. B.I.A.1.b	×				Shutdown definition has been revised to be more consistent with the NSPS
Att. B.I.A.1.c		×			Malfunction - Definition
Att. B.I.A.2		×			PM Standard of 43 nanograms per joule heat input for the boilers of Units 2 and 3
Att. B.I.A.3.a		×			Sulfur Dioxide Standard for coal burned in the boilers of Units 2 and 3
Att. B.I.A.3.b		×			Sulfur Dioxide Standard for used fuel oil burned in the boilers of Units 2 and 3
Att. B.I.A.3.c		×			Sulfur Dioxide Standard for combination fuel burned in the boilers of Units 2 and 3
Att. B.I.A.3.d		×			Compliance shall be based on the total heat input from all fuels burned

OP #1000109, References	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att. B.I.A.4.a		×			Nitrogen Oxide Standard for coal burned in the boilers of Units 2 and 3
Att. B.I.A.4.b		×			Nitrogen Oxide Standard for used fuel oil burned in the boilers of Units 2 and 3
Att. B.I.A.4.c		×			Nitrogen Oxide Standard for combination fuel burned in the boilers of Units 2 and 3
Att. B.I.A.5.a		×			Allowable fuel to be burned in the boilers of Units 2 and 3
Att. B.I.B.1		×			Steam Unit 1/Combined Cycle Operation of Steam Unit 1 and Gas Turbine No. 1. Opacity Standard
Att. B.I.B.2		×			PM standard for Steam Unit 1/Combined Cycle Operation of Steam Unit 1 and Gas Turbine No. 1
Att. B.I.B.3		×			Sulfur Dioxide standard of no more than 1.0 pounds per million Btu heat input for the auxiliary boiler
Att. B.I.B.4.a		×			High sulfur oil is not permitted to be burned as fuel unless low sulfur is not available.
Att. B.I.B.4.b		×			Only approved fuel shall be burned in Steam Unit 1.
Att. B.I.B.4.c		×			Only approved fuel shall be burned in Gas Turbine 1 and Steam Unit 1.
Att. B.I.B.5.c		×			Definition of heat input
Att. B.I.C.1		×			Gas Turbine Nos. 1, 2, and 3 and Gas Turbine 1 Startup Diesel Engine Opacity standard of 40%.
Att. B.I.C.2		×			Gas Turbine Nos. 1, 2, and 3 and Gas Turbine 1 Startup Diesel Engine PM standard.
Att. B.I.C.3		×			Gas Turbine Nos. 1, 2, and 3 and Gas Turbine 1 Startup Diesel Engine Sulfur Dioxide Standard
Att. B.I.C.4.a		×			High sulfur oil is not permitted to be burned as fuel unless low sulfur is not available.
Att. B.I.C.4.b		×			Only approved fuel shall be burned in Gas Turbine Nos. 1, 2, and 3
Att. B.I.C.5		×			Definition of heat input
Att. B.I.D.1		×			Opacity standard of 15% for hot water heater and space heaters

OP #1000109, References	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att. B.I.D.2		×			PM standard for hot water heater and space heaters
Att. B.I.D.3		×			Permittee shall burn propane for the hot water heater and natural gas for the space heaters.
Att. B.I.D.4		×			Definition of heat input
Att. B.I.E.1.a	×				Regular operation of Coal Preparation Plant - opacity standard revised to be 20%
Att. B.I.E.1.b		×			PM standard for regular operation of the Coal Preparation Plant
Att. B.I.E.2.a	×				Alternative operation of Coal Preparation Plant - opacity standard revised to be 20%
Att. B.I.E.2.b	×				PM standard for alternative operation of the Coal Preparation Plant
Att. B.I.F.1	×				Limestone handling system opacity standard revised to 20%
Att. B.I.F.2		×			Limestone handling system particulate matter standard
Att. B.I.G.1	×				Cooling tower opacity standard revised to 20%
Att. B.I.G.2		×			Cooling tower particulate matter standard
Att. B.I.G.3					Requirement to not emit gaseous or odorous material as to cause air pollution
Att. B.I.G.4		×			Option for Director to require the installation of abatement equipment to reduce or eliminate the discharge of air pollution
Att. B.I.H	×				Non-Point source and open burning requirements revised to reflect most recent permitting language
Att. B.I.I.1	×				Abrasive blasting activities requirements revised to reflect most recent permitting language
Att. B.I.I.2	×				Paint requirements revised to reflect most recent permitting language
Att. B.I.I.3	×				Solvent degreasing and gasoline and fuel oil transfer and dispensing requirements revised to reflect most recent permitting language
Att. B.I.I.4		×			Landfill operations requirements.

OP #1000109, References	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att. B.I.I.5		×			Mobile source requirements revised to reflect most recent permitting language
Att. B.I.I.6		×			Demolition/Renovation requirements
Att. B.I.I.7		×			Non-vehicle air conditioner maintenance and service
Att. B.II.A.1		×			Maintain and operate electrostatic precipitators associated with the boilers of units 2 and 3 in a manner consistent with good air pollution control practice
Att. B.II.A.2		×			Maintain and operate sulfur dioxide adsorption system associated with the boilers of units 2 and 3 in a manner consistent with good air pollution control practice
Att. B.II.B		×			Air pollution control requirements for the coal preparation plant
Att. B.II.C		×			Air pollution control requirements for the limestone handling system
Att. B.III.A	×				180 day requirement removed. Permittee must have a Method 9 certified observer available at all times
Att. B.III.B		×			All monitoring activities must be submitted with compliance certifications
Att. B.III.C		×			Any change in fuel type must be logged in ink or electronic format
Att. B.III.D.1.a		×			CEM systems is required for NOx, SOx and CO_2
Att. B.III.D.1.b		×			Requirements for CEM systems
Att. B.III.D.1.c		×			Recordkeeping and reporting requirements of 40 CFR Part 75 Subparts F and G
Att. B.III.D.1.d		×			File maintenance requirement
Att. B.III.D.1.e		×			Requirements for continuous opacity monitoring system (COMS)
Att. B.III.D.2.a		×			Requirement to evaluate opacity measurements from the COMS on a 24-hr rolling average
Att. B.III.D.2.b			×		Explanation that opacity is not necessarily correlated to particulate emissions
Att. B.III.D.2.c		×			Record in ink or electronic format the 24-hr opacity measurements performed

OP #1000109, References	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att. B.III.D.3.a		×			Excess emission reporting schedule
Att. B.III.D.3.a(1)		×			Excess emission for opacity
Att. B.III.E.3.a(2)		×			Excess emission for SO_2
Att. B.III.D.3.(3)		×			Excess emission for NOx
Att. B.III.D.3.b		×			Excess emission report requirements
Att. B.III.D.3.c		×			Excess emission report requirements
Att. B.III.E.1		×			Steam Unit 1 and combined cycle visible emissions monitoring while burning liquid fuel
Att. B.III.E.2		×			Steam Unit 1 and combined cycle particulate matter and sulfur dioxide monitoring while burning liquid fuel
Att. B.III.F		×			Monitoring requirements for gas turbines 1, 2, 3, and gas turbine 1 startup diesel engine
Att. B.III.G		×			Monitoring requirements for hot water heater and space heaters
Att. B.III.H		×			Monitoring requirements for coal preparation plant
Att. B.III.I		×			Monitoring requirements for limestone handling system
Att. B.III.J	×				Monitoring requirements for non-point sources revised to reflect recent permitting language
Att. B.III.K	×				Monitoring requirements for other periodic activities revised to reflect recent permitting language
Att. B.IV.A			×		EPA Reference Method 9 definition is incorporated by reference and therefore it is unnecessary.
Att. B.IV.B		×			Steam Units 2 and 3 testing requirements
Att. B.IV.C		×			Gas Turbines 1, 2, and 3 testing requirements
Att. B.IV.D		×			Coal Preparation plant testing requirements
Att. B.V.A		×			Used Oil Specification
Att. B.V.B		×			Used oil limitations

OP #1000109, References	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att. B.V.C	×				Recordkeeping and Reporting requirements for used oil were revised to include the amount of used oil burned in each boiler.
Att. B.V.D		×			Testing requirements for the use of used oil
Attachment "C"	×				Applicable Requirements have been identified in the permit shield and authority for permit conditions.
Attachment "D"		×			Equipment List
Attachment "E"			×		Insignificant Activities have been removed from the permit and put in the Technical Support Document.
Attachment "F"		×			Phase II Acid Rain Provisions

C. Significant Permit Revision #1001734 to Class I Operating Permit #1000109

This significant permit revision to the Class I operating permit was issued to Arizona Electric Power Cooperative on May 3, 2002.

Significant revision #1001734	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att. A. XII.E.		×			Excess emissions, Permit Deviations, and Emergency Reporting.
Att. A. XII.E.1		×			Establishes an affirmative defense for certain emissions in excess of a standard or limitation.
Att. A. XII.E.2		×			Affirmative defense for Malfunctions
Att. A. XII.E.3		×			Affirmative defense for startup and shutdown.
Att. A. XII.E.4		×			Affirmative defense for malfunction during scheduled maintenance.
Att. A. XII.E.5		×			Demonstration of reasonable and practicable measures.

Significant revision #1001734	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att. A. XXVI.		×			For all equipment subject to a New Source Performance Standard the Permittee shall comply with all applicable requirements contained in Subpart A of Title 40, Chapter 60 of the Code of Federal Regulations
Att. B.I.J		×			Gas Turbine No. 4
Att. B.I.J.1		×			PM10 Standard of not more than 13.5 tons per year on a 12 month rolling total.
Att. B.I.J.2		×			Sulfur Dioxide Standard
Att. B.I.J.2.a		×			Sulfur dioxide emissions shall not exceed 0.015 percent by volume at 15% oxygen on a dry basis.
Att. B.I.J.2.b		×			Sulfur dioxide emissions shall not exceed 39 tons per year on a 12 month rolling basis.
Att. B.I.J.2.c		×			The fuel burned in GT 4 shall not contain sulfur in excess of 0.3 percent by weight.
Att. B.I.J.3.		×			Nitrogen Oxide Standard
Att. B.I.J.3.a		×			Gas Turbine No. 4 shall not cause to be discharged into the atmosphere, emissions which exceed a acceptable standard.
Att. B.I.J.3.b		×			Nitrogen Oxide emissions shall not exceed 39 tons per year on a 12 month rolling basis.
Att. B.I.J.4		×			Carbon Monoxide emissions shall not exceed 95 tons per year on a 12 month rolling basis.
Att. B.I.J.5		×			Fuel limits
Att. B.I.J.5.a		×			Permittee shall only burn pipeline quality natural gas or fuel oil no. 2
Att. B.I.J.5.b		×			Fuel oil shall be used as a backup fuel only.
Att. B.I.J.5.c		×			The Permittee shall not burn fuel oil for more than 600 hours per year on a 12 month rolling basis.
Att. B.I.J.5.d		×			The use of natural gas may not exceed that calculated on a 12 month rolling basis.

Significant revision #1001734	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att. B.II.D.1		×			Nitrogen Oxide Air Pollution Control Equipment
Att. B.II.D.1.a		×			Water injection and a selective catalytic reduction shall be used to control nitrogen oxides emissions.
Att. B.II.D.1.a		×			At all times including startup, malfunction and shutdown, the water injection system and the SCR shall use good engineering practices to minimize nitrogen oxides emissions.
Att. B.II.D.1.b		×			At all times including startup, malfunction and shutdown, the water injection system and the SCR shall use good engineering practices to minimize nitrogen oxides emissions.
Att. B.II.D.2.a		×			An oxidation catalyst e shall be used to control Carbon Monoxide emissions.
Att. B.II.D.2.a		×			At all times including startup, malfunction and shutdown, the oxidation catalyst shall operate in a manner consistent with good engineering practices to minimize carbon monoxide emissions.
Att. B.III.L		×			Monitoring, Record Keeping and Reporting
Att. B.III.L.1		×			Permittee shall operate continuous emissions monitoring systems to measuring nitrogen oxides, carbon monoxide, oxygen or carbon dioxide as a diluent gas.
Att. B.III.L.2		×			The CO CEMs specified in Condition III.L.1 above shall be used to demonstrate compliance with the CO emission limitations in Condition I.J.4.
Att. B.III.L.3		×			Excess emissions for GT-4 using a CEMs for nitrogen oxides are defined as any three hour average during which the average emissions exceed those stated in Condition I.J.3.a.
Att. B.III.L.4		×			The NO_x CEMs shall be used to demonstrate compliance with the NO_x limitations of Condition I.J.3.b.
Att. B.III.L.5		×			Monitoring for NO_x
Att. B.III.L.5.a		×			The CEMs for NO_x

Significant revision #1001734	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att. B.III.L.5.a..(1)		×			40 CFR Part 75, Appendix A," Specification and Test Procedures".
Att. B.III.L.5.a..(2)		×			40 CFR Part 75, Appendix B, Quality Assurance and Quality Control Procedure.
Att. B.III.L.5.a..(3)		×			40 CFR Part 75, Appendix C, Missing Data Estimation Procedure
Att. B.III.L.5.a..(4)		×			40 CFR Part 75, Appendix F, Conversion Procedures
Att. B. III.L.5.a..(5) (a)		×			40 CFR Part 75.10(d)(1) Data Reduction Requirements
Att. B. III.L.5.a..(5) (b)		×			40 CFR Part 75.10(d)(1) Part 75 Subparts F and G respectively.
Att.B.III.L.6.a.		×			Monitoring for Carbon Monoxides
Att.B. III.L.6.a. (1)		×			40 CFR Part 60,Appendix B, Performance and test procedures for Carbon monoxide systems in stationary sources.
Att.B. III.L.6.a .(2)		×			40 CFR Part 60,Appendix F. Quality Assurance Procedures.
Att.B. III.L.6.a. (3)		×			The CO monitoring system and monitoring devices shall be installed and operation prior to conducting performance tests
Att.B. III.L.6.a.(4)		×			The Permittee shall conduct a performance evaluation of the CO CEMS during any performance test . The Permittee shall conduct CEMs performance evaluations as required by the Control Officer.
Att.B. III.L.6.a.(5)		×			The Permittee shall furnish the Control Officer within 60 days of completion two or upon request, more copies of a written report of the results of the performance evaluation

Significant revision #1001734	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att.B. III.L. 6.a.(6)		×			The Permittee shall check the zero (or low-level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once daily in accordance with written procedure. The zero and span shall, as a minimum, be adjusted whenever the 24-hour zero drift or 24-hour span drift exceeds two times the limits of the applicable performance specifications in 40 CFR Part 60, Appendix B. The system must allow the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified, whenever specified
Att.B. III.L. 6.a.(7)		×			Except for system breakdowns, repairs, calibration checks, and zero span adjustments required under paragraph (6) of this section, Permittee shall meet minimum frequency of operation as follows: The CO CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.
Att.B. III.L.7		×			Monitoring for SO_2 while burning Natural Gas The Permittee shall maintain a vendor-provided copy of that part of the Federal Energy Regulatory Commission (FERC)-approved Tariff agreement that contains the sulfur content and the lower heating value of the pipeline quality natural gas.
Att.B.III.L.8.a		×			Monitoring for PM_{10}

Significant revision #1001734	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att.B.III.L.8.b		×			The Permittee shall conduct a rolling twelve month calculation of the emissions of PM_{10} based initially on manufacturer's data, and after the initial performance tests upon the emission factors calculated for natural gas and fuel oil. The result of these tests and the recorded hours of operation of both fuels, shall be used to calculate the annual PM_{10} emission.
Att.B.III.L.9		×			The PM_{10} shall be calculated on a monthly basis, by the fifth working day of the month, and shall be compared to the emission limitation in I.J.1 to determine compliance.
Att.B.III.L.10		×			NOx and CO Emission Monitoring
Att.B.III.L.10.a		×			The Permittee shall use the NOx and CO CEMS data to calculate the amount of NOx and CO being emitted on a daily basis.
Att. B. III.L.10.a.(1)		×			When the NOx CEMS is inoperative for any reason, the Permittee shall compute NOx emissions using the procedures in 40 CFR Part 75, Subpart D.
Att.B. III.L.10.a.(2)		×			When the CO CEMS is inoperative for any reason, Permittee shall calculate CO emissions using the average of the 1-hour period prior to the CEMS failure and the 1-hour period following restoration of CEMS operation. This average shall be substituted into all 1-hour missing averages during the CEMS failure.
Att.B.III.L.10.b		×			By the fifth working day of each month, the Permittee shall calculate a rolling 12-month total of NOx and CO emissions for the previous month.
Att.B.III.L.11		×			Fuel Monitoring and Record Keeping
Att.B.III.L.11.a		×			The Permittee shall keep on record the contractual agreement with the liquid fuel vendor indicating the following information for each shipment of fuel oil No. 2:

Significant revision #1001734	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att.B.III.L.11.a.(1)		×			The name of the fuel oil supplier;
Att.B.III.L.11.a.(2)		×			The heating value of the fuel oil
Att.B.III.L.11.a.(3		×			The density of the fuel oil
Att.B.III.L.11.a.(4)		×			The sulfur content of the fuel oil from which the shipment came; and
Att.B.III.L.11.a.(5)		×			The method used to determine the sulfur content of the fuel oil.
Att.B.III.L.11.b		×			The Permittee shall record the following when making a fuel change including:
Att.B.III.L.11.b(1)		×			Type of fuel change;
Att.B.III.L.11.b(2)		×			Date and time of the fuel change; and
Att.B.III.L.11.b(3)		×			Hours of operation when burning each fuel
Att.B.III.L.12		×			Fuel Oil No. 2 Storage Tank - The Permittee shall keep readily accessible records showing the dimension of the storage vessel and the analysis showing the capacity of the storage vessel for the life of the source.
Att .B.III.M		×			Excess Emissions and Monitoring System Performance
Att.B.III.M.1		×			Excess emission and monitoring system performance (MSP) reports for Gas Turbine No. 4 shall be submitted to the Department and EPA Region IX every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and MSP report shall include the information required in Condition III.D.3 of Attachment "B" of Air Quality Class I Permit No. 1000109. Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

Significant revision #1001734	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att.B.III.M.1.a.		×			The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions.
Att.B.III.M.1.b.		×			Specific identification of each period of excess emissions that occurs during startups, shutdowns and malfunctions of the unit. The nature and cause of any malfunction (if known), and the corrective action taken or preventive measures adopted.
Att.B.III.M.1.c.		×			The date and time identifying each period when the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.
Att.B.III.M.1.d.		×			When no excess emissions have occurred or the continuous monitoring system(s) has not been inoperative, repaired, or adjusted, such information shall be stated in the report.
Att.B.III.M.2		×			The summary report form shall contain the information and be in the format shown in Figure 1 of §60.7 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored.
Att.B.III.M.2.a		×			If the total duration of excess emissions for the reporting period is less than 1 percent of the total operating time for the reporting period and CEMS downtime for the reporting period is less than 5 percent of the total operating time for the reporting period, only the summary report form shall be submitted and the excess emission report described in §60.7(c) need not be submitted unless requested by the Administrator.

Significant revision #1001734	Determination				Comments
	Revise	Keep	Delete	Stream-line	
Att.B.III.M.2.b		×			If the total duration of excess emissions for the reporting period is 1 percent or greater of the total operating time for the reporting period or the total CEMS downtime for the reporting period is 5 percent or greater of the total operating time for the reporting period, the summary report form and the excess emission report described in §60.7(c) shall both be submitted.
Att.B.IV.E		×			Testing Requirements – The Permittee shall conduct performance tests in accordance with the following
Att.B.IV.E.1.		×			Natural Gas
Att.B.IV.E.1.a.		×			Within 180 days after initial start-up the Permittee shall conduct the following performance tests:
Att.B.IV.E.1.a. (1)		×			NOx emissions test in accordance with EPA Reference Method 7 or 7E:
Att.B.IV.E.1.a (2)		×			CO emissions test in accordance with EPA Reference Method 10; and
Att.B.IV.E.1.a (3)		×			A particulate (PM_{10}) emissions test in accordance with EPA Reference Method 5.
Att.B.IV.E.1.b		×			After the initial performance test, the Permittee shall conduct annual Relative Accuracy Test Audit (RATA) test on the nitrogen oxides CEMS using EPA Reference Method 7 or 7E and on the carbon monoxide CEMS using EPA Reference Method 10; in accordance with 40 CFR 60. Appendix A
Att.B.IV.E.2		×			Fuel Oil No. 2 - Within 180 days after the first firing of fuel oil No.2, and while burning fuel oil No. 2 in the unit, the Permittee shall conduct a performance test for particulates (PM_{10}) on Gas Turbine No. 4 in accordance with EPA Reference Method 5 and furnish the Director with a written report of the performance test.

Condition I.J.5.b of Attachment "B" is hereby amended in Significant Revision No. 1001734:

Significant Revision #28077	**Determination**				**Comments**
	Revise	**Keep**	**Delete**	**Stream-line**	
ATT B.1.J.5.b		×			Emission Standards
ATT B.1.J		×			Gas Turbine No. 4. Fuel Limitation
ATT B.1.J.5.b		×			Fuel oil shall be used as an emergency back-up fuel only. This emergency fuel may be combusted for short periods as a normal maintenance practice to verify that the unit can safely combust the emergency fuel and to conduct performance tests.
ATT B.VI.		×			Air Pollution Control Equipment

Condition.B.VI.B of Attachment "B" is hereby amended in Significant Revision No.1001734					
ATT B.VI.B		×			Coal Preparation Plant
ATT BVI.B.1		×			Wet dust suppression shall be maintained and operated at the screen feeders during screening, and at the entrance and exit of the crusher during crushing, in a manner consistent with good air pollution control practices.
ATT BVI.B.2		×			Dry fogging systems shall be maintained and operated at the railcar unloading area, at the transfer point between Conveyor #1 and Conveyor #2, the Conveyor #2 stack-out tube, the transfer point between Conveyor #3 and Conveyors #4A and #4B and the three rotary plows, in a manner consistent with good air pollution control practices.

Significant Revision #28077	Determination				Comments
	Revise	Keep	Delete	Stream-line	
ATT BVI.B.3		×			Either wet suppression or dry fogging systems shall be maintained and operated at the track hopper feeders in a manner consistent with good air pollution control practices.
ATT BVI.B.4		×			The Permittee shall maintain and operate at all times the bag house used to capture particulate matter emissions associated with the coal silos in a manner consistent with good air pollution control practices.

VII. MONITORING REQUIREMENTS

A. Steam Units 2 and 3

1. Compliance Assurance Monitoring (CAM) (40 CFR 64) for Particulate Matter for Steam Units 2 & 3:

   Background

   a. Emission Unit Steam Units 2 and 3

   b. Facility Apache Generating Station, Cochise, AZ

   c. Description: Coal-Fired Utility Boilers

   d. Identification:

      i. Steam Unit 2 Boiler, Source ID 005, ORIS Code 000160

      ii. Steam Unit 3 Boiler, Source ID 006, ORIS Code 000160

2. Applicable Regulation, Emissions Limit, and Monitoring Requirements

   a. Regulation: A.A.C. R18-2-901.2 (40 CFR 60, Subpart D)

   b. Emission Limit: PM<0.1 lb/MMBtu

   c. Monitoring Continuous Opacity Monitoring System (COMS).

3. Control Technology

Hot-Side Electrostatic Precipitators

a. Monitoring Approach

Opacity is an indicator of PM emissions. Historic particulate emissions test data and concurrent opacity monitoring data submitted in the permit application and the revised CAM plan indicate that compliance with the applicable 20% opacity limit provides a significant margin for demonstrating continuous compliance with the applicable 0.1 lb/MMBtu PM limit. The opacity indicator range has been set as a 1 hour average opacity of less than 18%, as recorded by COMS.

The electrical parameters (i.e., secondary voltage and current across each ESP section) will constitute the secondary indicator for performance of the ESP. The range for the ESP electrical parameters will be identified within 30 days of permit issuance. The electrical parameters will be monitored on a continuous basis (at least once every 15 minutes), and recorded. In addition, if the 1 hour average opacity equals or exceeds 18%, the unit operation status (load change increase or decrease) will be recorded.

All indicator ranges exclude periods of startup and shutdown.

If the 1 hour average opacity equals or exceeds 18%, and the electrical parameters are also outside the established range, an excursion event will be recorded and reported. Corrective action will be taken to return all indicators to within their respective ranges.

b. Monitoring Approach Justification

Opacity was selected as the primary performance indicator because, as the opacity of emissions increases, it can be reasonably assumed that PM emissions increase. In addition, the facility has historically been required by permit to conduct annual PM testing, and past data indicates that the unit opacity limits provide a significant margin of compliance with the PM limits. The indicator range selected for opacity is a 1-hour rolling average opacity of less than 18%.

The secondary indicator range is the electrical parameters (secondary current and voltage for each section of each ESP). Monitoring the current and voltage on a continuous basis allows for a more accurate way of determining how the ESPs are operating. An indicator range for the electrical parameters will be established and submitted to ADEQ and EPA within 30 days after the permit is issued. Having continuous data of the electrical parameters allows the Department and EPA the flexibility to determine if the facility is in compliance in the future.

CAM Plan for ESP

Indicator and its measurement approach	Opacity from the stack shall be the primary indicator and continuous opacity monitoring systems (COMS) will be used as the measurement approach. The secondary indicator will be the electrical parameters (current and voltage) for each section of each ESP.
Indicator Range	The indicator range for opacity will be over a 1 hour rolling average of less than 18% opacity. The indicator range for the electrical parameters will be established within 30 days after the permit is issued will represent normal operating conditions.
Data representation	The data will represent normal operating conditions, this will exclude startup, shutdown, and malfunctions.
Verification of operational status	N/A
QA/QC practices and criteria	The Permittee is required to meet the QA/QC requirements of 40 CFR 60, Appendix B, Performance Specification 1, "Specification and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources"
Monitoring Frequency	The COMS must be in continuous operation and must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period. The source will also monitor and record the electrical parameters on a continuous basis (at least once every 15 minutes) for each section of each ESP.
Data Collection Procedure	The Permittee will reduce all data from the COMS to 6-minute averages. Six-minute opacity averages must be calculated from 36 or more data points equally spaced over each 6-minute period.
Averaging period	The Permittee will be required the monitor the opacity over a 1-hour averaging period.

4. Sulfur Dioxide

The Permittee is required to operate a continuous emissions monitoring system (CEMS) for recording emissions of sulfur dioxide. The CEMS will be used as CAM for sulfur dioxide for both units. The monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 75, Appendix A and B.

3. Nitrogen Oxides

The Permittee is required to operate a continuous emissions monitoring system (CEMS) for recording emissions of nitrogen oxides. The CEMS will be used as

CAM for nitrogen oxide for both units The monitoring system is required to meet the requirements of 40 CFR 60.13 and 40 CFR 75, Appendix A and B.

B. Steam Unit 1/Combined Cycle Operation of Steam Unit 1 and Gas Turbine No. 1

1. Opacity

   a. Permittee is required to operate a continuous opacity monitor to measure the opacity of gases exiting the stack.

   b. The Permittee is also required to monitor and record the number of hours fuel oil is burned continuously in the unit.

2. Particulate Matter (PM/PM_{10})

   When fuel oil is burned in the unit, the Permittee is required to monitor particulate matter emissions by monitoring the fuel burned in the unit. The Permittee is also required to monitor the heating value and ash content found in the contractual agreement with the liquid fuel vendor.

3. Sulfur Dioxide (SO_2)

   When fuel oil is burned, the Permittee is required to keep on record the fuel supplier certification including the name of the oil supplier; sulfur content and the heating value of the fuel from which the shipment came from; and the method used to determine the sulfur content of the oil.

4. Nitrogen Oxides (NO_x)

   The Permittee is required to operate, maintain, and calibrate a CEMS to monitor NO_x emissions.

C. Gas Turbine Nos. 1, 2, and 3,Gas Turbine Startup Engine, and Emergency Diesel Generator.

1. Opacity:

   When fuel oil is burned, the Permittee is required to monitor and record opacity according to the following schedule:

   a. When fuel oil is burned continuously for a time period > 48 hours but less than 168 hours, then one EPA Method 9 reading is required.

   b. When fuel oil is burned continuously for a time period > 168 hours, then for each 168 hour period one EPA Method 9 reading is required.

   The Permittee is also required to monitor and record the number of hours fuel oil is burned continuously in the units.

2. Particulate Matter(PM/PM_{10})

When fuel oil is burned in the unit, the Permittee is required to monitor particulate matter emissions by monitoring the fuel burned in the unit, including the heating value and the ash content.

3. Sulfur Dioxide (SO_2)

   a. Natural gas

   b. The Permittee is required to maintain a copy of the FERC approved Tariff agreement on-site.

4. Fuel oil:

   When fuel oil is burned, the Permittee is required to keep on record fuel supplier certification including the name of the oil supplier; the sulfur content and the heating value of the fuel from which the shipment came from; and the method used to determine the sulfur content of the oil.

D. Gas Turbine No. 4

1. Particulate Matter(PM/PM_{10})

   The Permittee must conduct a rolling twelve month calculation of the emissions of PM_{10} based initially on manufacturer's data, and after the initial performance tests upon the emission factors calculated for natural gas and fuel oil. The result of these tests and the recorded hours of operation of both fuels, will be used to calculate the annual PM_{10} emission.

2. Sulfur Dioxide

   a. While burning natural gas, the Permittee must maintain a vendor-provided copy of that part of the Federal Energy Regulatory Commission (FERC)-approved Tariff agreement that contains the sulfur content and the lower heating value of the pipeline quality natural gas.

   b. While burning fuel oil, the Permittee must maintain a records of fuel supplier certifications that including the name of the oil supplier, the sulfur content of the oil, the heating content of the oil, and the method used to determine the sulfur content of the oil.

3. Nitrogen Oxides

   The Permittee is required to install and operate continuous emissions monitors to track nitrogen oxide emissions.

4. Carbon Monoxide

   The Permittee is required to install and operate continuous emissions monitors to track carbon monoxide emissions.

E. Coal Preparation Plant

Opacity

1. Normal and Alternative Operation

   The Permittee is required to make a weekly survey of the visible emissions from established points. The Permittee is required to create a record of the date on which the survey was taken, the name of the observer, and the results of the survey. If the visible emissions do not appear to exceed the standard, the Permittee would note in the record that the visible emissions were of low opacity, and it did not require a Method 9 to be performed.

2. While under Alternative Operation, the Permittee is also required to keep a record of the operating times of each piece of equipment. The Permittee is also required to conduct at least one opacity observation each time a piece of equipment is operated.

F. Limestone Handling Plant

1. The Permittee is required to maintain a record of daily production rates of limestone produced.

2. The Permittee is required to make a weekly survey of the visible emissions from the entire limestone plant including all the enclosed transfer points, the exposed transfer points, the storage pile, and the bag filter. The Permittee is required to create a record of the date on which the survey was taken, the name of the observer, and the results of the survey. If the visible emissions do not appear to exceed the standard, the Permittee would note in the record that the visible emissions were of low opacity, and it did not require a Method 9 to be performed.

G. Fugitive Dust sources

Monitoring and recordkeeping requirements for these fugitive dust sources include a record of the date and type of activity performed and the type of controls used. Also, monitoring requirements for the applicable open burning rule may be satisfied by keeping all open burn permits on file.

H. Other Periodic Activities

1. Abrasive Blasting

   The Permittee is required to log the following information each time an abrasive blasting project is conducted

   a. The date the project was conducted;

   b. The duration of the project; and

c. The type of control measures employed.

2. Spray Painting

The Permittee is required to log the following information each time a spray painting project is conducted:

a. The date the project was conducted;

b. The duration of the project;

c. Type of control measures employed;

d. Material Safety Data Sheets for all paints and solvents used in the project; and

e. The amount of paint consumed during the project.

3. Mobile Sources

The Permittee is required to keep a record of all emissions related maintenance activities performed on Permittee's mobile sources stationed at the facility as per manufacturer's specifications.

4. Asbestos Demolition/Renovation

The Permittee is required to keep a record of all required paperwork on file for the purposes of monitoring and recordkeeping. The required paperwork includes "NESHAP Notification for Renovation and Demolition Activities" form and all supporting documents.

5. Non-vehicle Air Conditioner Maintenance and/or Services

The Permittee is required to keep a record of all paperwork required by the applicable requirements of 40 CFR 82 - Subpart F on file for the purposes of monitoring and recordkeeping.

VIII. TESTING REQUIREMENTS

A. Steam Units 2 and 3

The Permittee is required to perform annual performance tests for opacity, particulate matter, SO_2 and NO_x in accordance with 40 CFR Part 60, Subpart D.

B. Gas Turbines

The Permittee is required to test each unit for conventional air pollutants that are emitted in quantities above 100 tons in a year based on the schedule given in Conditions IV.C.3., IV.E. and IV.F of the permit. The reasons for this test are as follows:

1. The test will have a direct impact on the annual emission fee;

2. The test will be the basis for any future modification; and

3. The test will help to get a clearer picture of the actual emissions from major sources in Arizona. While emission factors play an important role in the air pollution control program, they do not yield reliable data unless they are either developed directly from the emission unit in question or substitutes for a proven mass-balance relationship. Thus, testing would provide valuable information.

IX. INSIGNIFICANT ACTIVITIES

An "insignificant activity" means an activity in an emission unit that is not otherwise subject to any applicable requirement and belongs to a specific category. Initially the 345 hp Emergency Caterpillar Diesel Generator, Model SR was included as "insignificant". The Diesel Generator is subject to Arizona Administrative code R18-2-719.A. Standards of Performance for Existing Rotating Machinery.

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PERSUANT TO A.A.C. R18-2-101.57	DETERMINDED TO BE INSIGNIFICANT?	ADEQ's DETERMINATION
1	345-hp Emergency Caterpillar Diesel Generator, Model SR-4, S/N 90 U 1386	No	Based on A.A.C. R18-2-719.A
2	Analytical Laboratory	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.i
3	5,000-gallon Sulfuric Acid Storage Tanks (2)	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
4	15,000-gallon Sulfuric Acid Storage Tanks (2)	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
5	300-gallon Phosphate Solution Storage Tanks (2)	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
6	200-gallon Phosphate Solution Storage Tank	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
7	160,000-gallon Absorbent Feed Tanks (2)	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PERSUANT TO A.A.C. R18-2-101.57	DETERMINDED TO BE INSIGNIFICANT?	ADEQ's DETERMINATION
8	38,100-gallon Limestone Reagent Tank	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
9	Equipment Wash Facility Propane Tank	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
10	Natural Gas Piping System	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
11	10,000-gallon Diesel AST	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.c
12	300-gallon 345-hp Generator Diesel AST	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
13	500-gallon Portable Diesel AST	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.c
14	700,000-gallon Fuel Oil Storage Tank	No	Fails A.A.C. R18-2-101.57.c
15	Lube Oil Storage	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
16	5,000-gallon Used Oil AST	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
17	10,000-gallon Gasoline AST	No	Based on A.A.C. R18-2-710

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PERSUANT TO A.A.C. R18-2-101.57	DETERMINDED TO BE INSIGNIFICANT?	ADEQ's DETERMINATION
18	Fuel Oil Piping System	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
19	Used Oil Satellite Collection Area	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
20	Used Oil/RCRA/TSCA Waste Accumulation Area	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
21	2,000-gallon Sodium Hypochlorite Storage Tanks (2)	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
22	Polymer Storage Tanks for Water Treatment Chemicals	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
23	Dust Suppression Chemical Storage Tank	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
24	Steam Unit 2 Boiler Blow down Tank (C-F System)	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
25	Steam Unit 3 Boiler Blow down Tank (C-F System)	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
26	192,000-gallon Condensate Storage Tanks (2)	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PERSUANT TO A.A.C. R18-2-101.57	DETERMINDED TO BE INSIGNIFICANT?	ADEQ's DETERMINATION
27	45,000-gallon Condensate Storage Tanks (2)	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
28	250,000 Treated Water Tank	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
29	Septic Tank/Leach Field System	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
30	Office and Administrative Facilities	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.a
31	Grounds keeping Activities	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.a
32	Herbicide/Pesticide Use	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.a
33	Firefighter Training Area	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
34	Emergency Flares	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
35	Kitchen/Break-room Facilities	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.a

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PERSUANT TO A.A.C. R18-2-101.57	DETERMINDED TO BE INSIGNIFICANT?	ADEQ's DETERMINATION
36	Cleaning Equipment	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.a
37	Unit Maintenance/Repair Activities	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
38	Lubricant Coating Operations	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
39	Medical Activities	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
40	Manually Operated Tool Use	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
41	Emission Sampling Equipment	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
42	Process Equipment Seals, Valves and Flanges	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
43	Brazing, Soldering, or Welding Operations	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
44	Battery Recharging	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PERSUANT TO A.A.C. R18-2-101.57	DETERMINDED TO BE INSIGNIFICANT?	ADEQ's DETERMINATION
45	Aerosol Can Use	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
46	Plastic Pipe Welding	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
47	Acetylene, Butane, and Propane Torches	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
48	Steam Vents, Condenser Vents, and Boiler Blow down	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
49	Portable Steam Cleaning Equipment	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
50	Blast-cleaning Equipment	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
51	Cooling Tower Blow down Pond	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
52	Coal Storage Pile Retention Basin	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
53	Pump/Motor Oil Reservoirs	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PERSUANT TO A.A.C. R18-2-101.57	DETERMINDED TO BE INSIGNIFICANT?	ADEQ's DETERMINATION
54	Transformer Vents	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
55	Hydraulic System Reservoirs	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
56	Adhesive Use	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
57	Caulking	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
58	Electric Motors	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
59	Cathodic Protection Systems	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
60	Corona	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
61	Filter Draining	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
62	Heavy Equipment Maintenance Shop	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PERSUANT TO A.A.C. R18-2-101.57	DETERMINDED TO BE INSIGNIFICANT?	ADEQ's DETERMINATION
63	Station Transformers	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
64	Circuit Breakers	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
65	Generation Unit Gas Vents	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
66	Flammable Product Storage Cabinets	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
67	Coal Feeder Cleaning	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
68	Hot Coal Handling	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
69	Test Gases and Bottled Gases	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
70	Storm water Systems Including Non-process Sumps and Open or Covered Drainage Troughs from Process Areas for Rainwater Handling.	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
71	Case Hardening	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j

No.	POTENTIAL EMISSION POINTS CLASSIFIED AS "INSIGNIFICANT ACTIVITIES" PERSUANT TO A.A.C. R18-2-101.57	DETERMINDED TO BE INSIGNIFICANT?	ADEQ's DETERMINATION
72	Gas Turbine 4 9,200 - gallon Ammonia Storage Tank	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
73	Gas Turbine 4 Gas Compressor Building	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
74	Gas Turbine 4 Aqueous Ammonia Grid	Yes	Insignificant Activity pursuant to A.A.C. R18-2-101.57.j
75	Gas Turbine 4 132,000-gallon Fuel Oil Tank	No	Fails A.A.C. R18-2-101.57.c

X. LIST OF ABBREVIATIONS

AAAQG .... Arizona Ambient Air Quality Guideline
A.A.C. .... Arizona Administrative Code
ADEQ .... Arizona Department of Environmental Quality
AEPCO .... Arizona Electric Power Cooperative, Inc.
AQD .... Air Quality Division
AQG. .... Air Quality Guidelines
A.R.S. .... Arizona Revised Statutes
Btu .... British Thermal Units
CAM .... Compliance Assurance Monitoring
CFR .... Code of Federal Regulations
CO .... Carbon Monoxide
CO_2 .... Carbon Dioxide
DEGF .... Degrees Fahrenheit
DEGK .... Degrees Kelvin
EPA .... U.S. Environmental Protection Agency
ESP .... Electrostatic Precipitator
FERC .... Federal Energy Regulatory Commission
ft .... Feet
GT .... Gas Turbine
g .... Grams
HAP .... Hazardous Air Pollutant
hp .... Horsepower
hr .... Hour
IC .... Internal Combustion
lb .... Pound
lb/MMBtu .... Pounds per Million British Thermal Units
lb/TBtu .... Pounds per Trillion British Thermal Units
m .... Meter
MCF .... Million Cubic Feet
MMBtu .... Million British Thermal Units
MMBtu/hr .... Million British Thermal Units/hour
MW .... Megawatt
NAAQS .... National Ambient Air Quality Standard
NESHAP .... National Emission Standards for Hazardous Air Pollutants
NO_x .... Nitrogen Oxide
NO_2 .... Nitrogen Dioxide
O_3 .... Ozone
Pb .... Lead
PM .... Particulate Matter
PM_{10} .... Particulate Matter Nominally less than 10 Micrometers
ppm .... Parts per million
ppmvd .... Parts per million by Volume Dry
psia .... Pounds per square Inch (absolute)
PTE .... Potential-to-Emit
PSEU .... Pollutant-Specific Emission Units
SCR .... Selective Catalytic Reduction

SDAS .... Sulfur Dioxide Absorption System
s .... Seconds
SO_2 .... Sulfur Dioxide
ST .... Steam Unit
T/R .... Transformer-Rectifier
TPY .... Tons per Year
TSP .... Total Suspended Particulate
VOC .... Volatile Organic Compound
yr .... Year