TECHNICAL SUPPORT DOCUMENT (TSD)

October 2016

I. General Comments:

A. Company Information

1. Tucson Electric Power – Irvington Generating Station

2. Source Address: 3950 East Irvington Road, Tucson, AZ 85714.
   Mailing Address: 88 East Broadway Blvd, Mail Stop HQW705, Tucson Arizona or
   P.O. Box 711, Mail Stop HQW705, Tucson, AZ 85702.

B. Background

PDEQ received an application for the renewal of the air quality permit (#1052) for the TEP – Irvington Generating Station (TEP-IGS) also known as the "H. Wilson Sundt Generating Station" on March 21, 2012. This TSD has been updated for the renewal (See Appendix A for Previous TSD documents).

History

TEP-IGS is an electric utility power generating station that generates electricity by fossil fuel combustion (natural gas, liquid fuel and landfill gas). The original construction of TEP-IGS did not provide any capacity to fire coal as an alternate fuel and was regulated by the Pima County Health Services Department. In 1980 the Department of Energy (DOE) promulgated regulations that required certain large power plants to convert their operations to have the additional capacity to fire coal. Since Arizona Revised Statutes (ARS) provide that the State has original jurisdiction for coal fired electrical generating stations, the Arizona Department of Environmental Quality (ADEQ) assumed oversight from Pima County and implemented the permitting and air quality regulation of TEP-IGS. TEP applied for and received an installation permit for the coal conversion project (See Appendix B for the Arizona Department of Health Services Installation Permit (# 1156)).

Although the initial plan was to convert each electric utility steam generating unit (EUSGU or EGU) at the station, only Unit I4 was converted. Since the change was mandated by a government order, NSR requirements were not applicable [Ref. definition for "major modification" in Pima County Code (PCC) and Arizona Administrative Code (AAC) – c.ii]. The NSPS definition for "modification" also exempts mandatory coal conversion projects [Ref. 40 CFR 60.145(e)(4) and CAA Sec 111(a)(8)]. For this reason, 40 CFR Part 60, Subpart D requirements did not apply to Unit I4 or the coal preparation plant.

In the late 1990's TEP requested that jurisdiction over TEP-IGS be returned to the Pima County Department of Environmental Quality (PDEQ); the transfer was completed shortly after ADEQ issued a 5-year Class I permit to TEP IGS (issue date July 26, 1999). PDEQ's authority to have jurisdiction over the generating station and any standards adopted by ADEQ affecting coal fired EUSGUs is through a delegation agreement signed between PDEQ and ADEQ. Upon expiration of the permit, PDEQ issued the renewal permit on September 24, 2007.

Changes Since Issuance of Previous Permit

The current permit was revised in 2010 to include the state mercury rule (SMR) emission monitoring standards applicable to Unit I4 and to extend the SMR compliance deadline to the 12-month calendar year period ending on December 31, 2016. In addition, the permit was revised to incorporate NSPS, Subpart IIII requirements for an affected emergency generator at the facility (See Appendix C for the current air quality permit).

A significant permit revision application for Unit I4 was submitted as required on December 26, 2013 to include all applicable MATS emission limits, controls, monitoring, recordkeeping, and reporting requirements as set forth in 40 CFR Part 63, Subpart UUUUU – NESHAP: Coal- and Oil-Fired Electric Utility Steam Generating Units. Along with the application, an extension request was submitted to the director of the Air Quality Division of the Arizona Department of Environmental Quality (ADEQ) in accordance with 40 CFR 63.6(i)(4)(i)(A) for the installation of emission controls for Unit I4. On January 28, 2014 ADEQ approved the one year MATS compliance extension. With respect to Units I1, I2, and I3 the MATS does not apply since they have been operated as existing gas fired units (See Appendix D for the MATS compliance extension letter).

During this renewal, Unit I4 became subject to the Arizona Regional Haze State and Interstate Visibility Transport State Implementation Program requirements for Best Available Retrofit Technology (BART) [Ref. FIP Final Rule, 40 CFR 52.145(j), Promulgated September 3, 2014, Federal Register Vol. 79, No. 170.] This rule is effective October 3, 2014 and requires compliance no later than December 31, 2017 when choosing to combust only natural gas or natural gas combined with landfill gas. TEP-IGS has chosen to comply with this rule by firing natural gas exclusively in Unit I4 and will no longer fire fuel oil in the unit as an alternate fuel (See Appendix D for letter on selection of regional haze limits).

During the permit renewal process, TEP discovered that the language in 40 CFR §52.145(j)(8)(i)(A) and (B) (see below), is problematic for monitoring NOx emissions from Sundt Unit 4 (a natural gas-fired boiler). TEP requested assistance from EPA Region 9 to allow Sundt Unit 4 to select acceptable continuous emission monitoring options allowed by 40 CFR 75.

> §52.145(j)(8)*(i) Continuous emission monitoring system. (A) At all times after the compliance date specified in paragraph (j)(6) of this section, the owner/operator of the unit shall maintain, calibrate, and operate CEMS, in full compliance with the requirements found at 40 CFR part 75, to accurately measure* NO_X*, diluent, and stack gas volumetric flow rate from the unit. All valid CEMS hourly data shall be used to determine compliance with the emission limitation for* NO_X *in paragraph (j)(4) of this section. When the CEMS is out-of-control as defined by 40 CFR part 75, the CEMS data shall be treated as missing data and not used to calculate the emission average. Each required CEMS must obtain valid data for at least ninety (90) percent of the unit operating hours, on an annual basis.*
>
> *(8)(i)(B) The owner/operator of the unit shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75. In addition to these part 75 requirements, relative accuracy test audits shall be calculated for both the NOX pounds per hour measurement and the heat input measurement. The CEMS monitoring data shall not be bias adjusted. Calculations of relative accuracy for lb/hr of NOX and heat input shall be performed each time the CEMS undergo relative accuracy testing.*

It was agreed by TEP, PDEQ, and EPA Region 9 that the language for continuous emission monitoring systems in §52.145(j)(8)*(i)*(A) and (B) (above) should be corrected to allow TEP to select a monitoring approach that is consistent with the full text of 40 CFR Part 75. There are several problems with the current language in §52.145(j)(8)*(i)*(A) and (B). The first is that it contains specific language which limits TEP from various monitoring options that are allowed under the full text of 40 CFR Part 75. The second problem is that it specifically requires a stack gas volumetric flow monitor, and includes specific requirements for RATA testing which assume a stack gas volumetric flow monitor is in use which is contrary to the requirements of 40 CFR 75. In addition, the NO_X-Diluent CEMS RATA unit of measurement should be lbs/mmBtu and not lb/hr. In Part 75, for a NO_X-diluent monitor system RATA the unit of measurement is lbs/mmBtu. Once again, it would be best to have language that Sundt Unit 4 is required to follow the Part 75 requirements for performing RATAs on the NO_X-diluent system.

Sundt Unit 4 has selected the better-than BART option meaning that it is now a natural gas fired unit and has ceased burning coal. For a natural gas-fired boiler a stack gas volumetric flow monitor is not required by 40 CFR 75 nor is it needed to determine SO2 or NO_X rate. For example, the current Part 75 monitoring approach for Sundt Unit 3, which is a natural gas-fired unit, consists of a NO_X monitor, a diluent monitor, and fuel flow monitoring. The heat input is calculated using 40 CFR 75 equation D-6, the NO_X rate is calculated using 40 CFR 75 equation F-5 and the SO2 emission rate is calculated using equation D-5. Equations D-5, D-6 and F-5 (see equations below) do not require a stack gas volumetric flow monitor; instead a fuel flow monitor is used. For Sundt Unit 4, the monitoring approach used by Sundt Unit 3 would not be allowed based on the current language in §52.145(j)(8)*(i)*(A) and (B). TEP is considering the use of a similar monitoring approach in the future for Unit 4, but the specific language found in §52.145(j)(8)*(i)*(A) and (B) will need to be corrected to allow the monitoring approach.

<u>Equation D-5</u>

$$\mathbf{SO_2 rate = ER \times HI\ rate}$$

Where:

SO_2rate = Hourly mass emission rate of SO_2 from combustion of a gaseous fuel, lb/hr.

ER = SO_2 emission rate from section 2.3.1.1 or 2.3.2.1.1, of appendix D, lb/mmBtu.

HI_{rate} = Hourly heat input rate of a gaseous fuel, calculated using procedures in section 3.4.1 of this appendix, in mmBtu/hr.

<u>Equation D-6</u>

$$\mathbf{HI\ rate\text{-}gas = GAS\ rate \times GCV\ gas \div 10^6}$$

Where:

$HI_{rate\text{-}gas}$ = Hourly heat input rate from combustion of the gaseous fuel, mmBtu/hr.

GAS_{rate} = Average volumetric flow rate of fuel, for the portion of the hour in which the unit operated, 100 scf/hr.

GCV_{gas} = Gross calorific value of gaseous fuel, Btu/100 scf. **10^6** = Conversion of Btu to mmBtu.

<u>Equation F-5</u>

$$\mathbf{E = K\ C_h\ F\ ((20.9) \div (20.9 - \%O_2))}$$

Where:

K = 1.194×10^{-7} (lb/dscf)/ppm NO_X.

E = Pollutant emissions during unit operation, lb/mmBtu.

C_h = Hourly average pollutant concentration during unit operation, ppm.

$\%O_2$= Oxygen volume during unit operation (expressed as percent O_2).

The NO_X lb/mmBtu (Eq. F-5) can be multiplied by the hourly heat input mmbtu/hr (Eq. D-6) to obtain the hourly NO_X emission rate, lbs/hr.

On August 19, 2016, a meeting between TEP, PDEQ, and EPA Region 9 determined that the following language should be included in the Title V renewal. It was agreed by all that the language was appropriate and would serve as a technical correction to replace language in §52.145(j)(8)*(i)*(A) and (B) for the better-than BART option. For this reason, the following language has been proposed to allow the facility to utilize all applicable Part 75 monitoring approaches.

(8)(i) Continuous emission monitoring system. (A) At all times after the compliance date specified in paragraph (j)(6) of this section, the owner/operator of the unit shall maintain, calibrate, and operate CEMS, in full compliance with the requirements found at 40 CFR part 75. All valid CEMS hourly data shall be used to determine compliance with the emission limitation for NO_X in paragraph (j)(4) of this section. When the CEMS is out-of-control as defined by 40 CFR part 75, the CEMS data shall be treated as missing data and not used to calculate the emission average. Each required CEMS must obtain valid data for at least ninety (90) percent of the unit operating hours, on an annual basis.

(8)(i)(B) The owner/operator of the unit shall comply with the quality assurance procedures for CEMS found in 40 CFR part 75. The CEMS monitoring data shall not be bias adjusted.

It was also agreed during the August 19, 2016 meeting, that EPA Region 9 would review both the TSD, and the draft Permit language prior to the public comment period.

Finally, during this renewal, PDEQ confirmed that Unit I4 permanently switched to firing only natural gas and landfill gas and the operation of the coal and fly ash handling equipment associated with unit I4 has been suspended. In addition the previously permitted auxiliary boiler at the facility has been decommissioned and is no longer in operation.

C. Attainment Classification

TEP-IGS is located in a region that is designated as attainment for all criteria pollutants.

II. Source Description

A. Process Description

TEP-IGS generates electricity using two fossil fuel fired processes: (1) Steam Turbine Cycle and (2) Combustion Turbine Cycle. In addition to these, there are several support facilities, some of which contain applicable requirements that are addressed by the permit.

1. Steam Turbine Cycle

   There are three distinct units in this process: (1) Boiler; (2) Turbine; and (3) Generator.

   a. Boiler

      Water is converted to steam via combustion of fuel and heat transfer. Steam is routed to turbines while the exhaust gasses and pollutants produced during combustion are released to the ambient atmosphere after passing though air pollution controls (if required). The concentrations of pollutants released into the atmosphere depend on the fuel fired. Typical pollutants are Particulate Matter (PM), Sulfur Dioxides (SO_2), Nitrogen Oxides (NO_X), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC). Specific pollutant emission rates are provided in Section IV of this document.

b. Turbine

Steam exiting the boilers enters a turbine unit. The high-pressure steam passes through rotating blades which cause the turbine shaft to rotate converting the thermal energy of the steam into mechanical energy. After passing through the turbine, the steam is sent through a condenser and is recirculated to the boiler. The only process material used by the turbine unit is steam; thus there are no emissions.

c. Generator

The turbine drives the generator which, in turn, produces electrical energy. There are no process materials and no emissions from these units.

2. Combustion Turbine Cycle

There are two distinct units in this process: (1) Combustion Turbine; and (2) Generator

a. Combustion Turbine,

Fuel and air are mixed and injected into a combustion chamber where they are ignited. The hot combustion gases pass over the turbine blades. The resulting movement of the blades causes the shaft to rotate. Exhaust gasses and pollutants produced during combustion are released to the ambient atmosphere after passing through air pollution controls (if required). Emissions resulting from combustion typically include PM, SO_2, NO_X, CO and VOC. Representative emission rates are provided in Section IV of this document.

b. Generator.

The turbine drives the generator which, in turn, produces electrical energy. There are no process materials and no emissions from these units.

3. Support Facilities

Other equipment, operations and process that function as support facilities are turbine starter engines, emergency generators, and cooling towers. Pollutants include PM, SO_2, NOx, CO, and VOC.

B. Operating Capacity and Schedule

TEP-IGS requires the flexibility to operate 24 hours a day, 365 days a year. The net capacity of each power production unit is as follows:

1. Fossil Fuel Fired Steam Generating Units:

a. UNIT I1 – 81 MW
b. UNIT I2 – 81 MW
c. UNIT I3 – 104 MW
d. UNIT I4 – 156 MW

2. Stationary Combustion Turbines:

a. UNIT IGT1 – 24 MW
b. UNIT IGT2 – 24.5 MW
c. UNIT IGT3 – < 25 MW (Reserved for future installation See Alternate Operating Scenarios)

C. Applicability Categories

The following categories are addressed by the permit:

1. Facility General Provisions
2. Electric Steam Generating Units EUG's (Units - I1, I2 and I3)
3. Electric Steam Generating Units (I4)
4. Unit I4 – Regional Haze Implementation Plan
5. Cooling Towers (I1E, I2D, I3D, and I4E)
6. Stationary Rotating Machinery (IGT1, IGT1A, IGT2, and IGT2A)
7. Emergency Generators – Local Requirements (EGEN1 and EGEN2)
8. NESHAP Subpart ZZZZ Requirements for Emergency Generators (EGEN1, IGT1A, and IGT2A)
9. NSPS Emergency Generator Requirements (EGEN2)
10. Nonpoint Fugitive Dust Sources
11. Use of Paints
12. Abrasive Blasting

D. Air Pollution Control Equipment

Air Pollution Control Equipment is required for the following equipment and processes:

1. UNIT IGT3

   Upon purchasing the unit, the Permittee is required to install and operate a water injection system or its equivalent to control NO_X emissions.

III. Regulatory History

TEP is currently in compliance with permit and regulatory requirements.

A. Testing & Inspections

Inspections have been conducted regularly since PDEQ took over jurisdiction from ADEQ. The last completed inspection was concluded in 2014.

B. Excess Emissions

There have been no Notices of Violations for any excess emissions.

IV. Emission Estimates

The following table summarizes IGS annual potential to emit of air pollutants by each emission unit and by facility-wide total. The emission estimate is to establish "major source" status of IGS pursuant to CAA Sec 501(2). Other use with the estimate may include comparing source potential-to-emit with emissions inventory and test data, or with emission rates allowable by relevant standards. This emission estimate is not meant to establish any baseline emission levels. These emission figures are not meant to be emission limitations of any form.

The majority of IGS air emissions come from the boiler units. Although natural gas is the primary fuel consumed by the boilers, Units I1-I3 are permitted to co-fire natural gas with fuel oils and Unit I4 is permitted to co-fire natural gas with landfill gas. To accommodate the co-firing scenario, a fuel mix of 85% natural gas and 15% diesel was used in calculating emissions for Units I1-I3. Similarly, a fuel mix of 95% natural gas and 5% landfill gas was used for Unit I4. Other assumptions are presented in the summary table's footnotes.

For Title V air permitting purposes, the threshold to trigger a major source status is 100 tpy of any criteria air pollutant, 10 tpy of any single hazardous air pollutant (HAP), 25 tpy of any HAPs combination, 100,000 tpy CO2 equivalent emissions of greenhouse gases. As shown in the summary table, IGS is a major Title V source for the following air pollutants: PM_{10}, $PM_{2.5}$, SO_2, NO_X, CO, CO_{2e}, VOC, and HAPs.

IGS Facility Wide Annual Potential to Emit (tons/year) Summary [1]

Source	Fuel [2]	PM-10		PM-2.5		SO2		NO_X		CO		CO2e		VOC		Lead		Total HAPs	
		lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Boiler Unit I1	85% Natural Gas	6.69	29.29	6.69	29.29	1.89	8.26	149.60	655.23	21.12	92.50	106,239	465,328	4.84	21.20	4.40E-04	1.93E-03	1.66	7.28
	15% Diesel Fuel	3.73	16.35	3.73	16.35	144.59	633.31	27.15	118.93	5.66	24.78	25,322	110,912	0.23	0.99	1.43E-03	6.24E-03	0.08	0.37
Boiler Unit I2	85% Natural Gas	6.61	28.97	6.61	28.97	1.86	8.17	147.92	647.91	20.88	91.47	105,052	460,129	4.79	20.96	4.35E-04	1.91E-03	1.64	7.20
	15% Diesel Fuel	3.69	16.17	3.69	16.17	142.98	626.24	26.85	117.60	5.59	24.50	25,040	109,673	0.22	0.98	1.41E-03	6.17E-03	0.08	0.36
Boiler Unit I3	85% Natural Gas	6.87	30.10	6.87	30.10	1.94	8.49	153.73	673.34	21.70	95.06	109,176	478,189	4.97	21.78	4.52E-04	1.98E-03	1.71	7.48
	15% Diesel Fuel	3.84	16.81	3.84	16.81	148.59	650.82	27.90	122.22	5.81	25.46	26,022	113,978	0.23	1.02	1.46E-03	6.42E-03	0.09	0.38
Boiler Unit I4	95% Natural Gas	11.64	50.97	11.64	50.97	3.28	14.37	214.36	938.88	128.61	563.33	184,853	809,655	8.42	36.88	7.66E-04	3.35E-03	2.89	12.66
	5% Landfill Gas	0.67	2.94	0.67	2.94	1.52	6.65	2.70	11.83	0.47	2.04	178	780	0.03	0.13	0.00	0.00	2.67	11.67
Turbine IGT1	Natural Gas	3.30	14.44	3.30	14.44	1.05	4.60	159.84	700.10	40.96	179.40	55,500	243,089	1.05	4.59	n/a	n/a	0.51	2.25
Turbine IGT2	Natural Gas	3.30	14.44	3.30	14.44	1.05	4.60	159.84	700.10	40.96	179.40	55,500	243,089	1.05	4.59	n/a	n/a	0.51	2.25
Turbine IGT3	Natural Gas	3.05	0.33	3.05	0.33	0.97	0.11	148.00	13.92	37.93	4.13	51,389	5,598	0.97	0.11	n/a	n/a	0.48	0.05
Starter Engine IGT1A	Diesel	0.29	0.02	0.28	0.02	4.71	0.34	15.24	1.11	3.49	0.25	835	61	0.41	0.03	n/a	n/a	0.01	0.00
Starter Engine IGT2A	Diesel	0.29	0.02	0.28	0.02	4.71	0.34	15.24	1.11	3.49	0.25	835	61	0.41	0.03	n/a	n/a	0.01	0.00
Starter Engine IGT3A	Diesel	0.29	0.02	0.28	0.02	4.71	0.34	15.24	1.11	3.49	0.25	835	61	0.41	0.03	n/a	n/a	0.01	0.00
EGEN 1 (Kohler)	Diesel	0.21	0.05	0.21	0.05	0.01	0.00	4.18	1.05	3.66	0.91	655	164	0.45	0.11	n/a	n/a	0.02	0.00
EGEN 2 (Caterpillar)	Diesel	0.77	0.19	0.77	0.19	0.72	0.18	10.82	2.70	2.33	0.58	410	102	0.86	0.22	n/a	n/a	0.02	0.00
Cooling Tower I1E		8.19	35.86	n/a	n/a														
Cooling Tower I2E		8.19	35.86	n/a	n/a														
Cooling Tower I3E		11.37	49.80	n/a	n/a														
Cooling Tower I4E		15.46	67.73	n/a	n/a														
Fuel Oil Tanks/Paint Booths														n/a	14.96				
Facility Wide Annual Potential to Emit (tons/year)		**410.36**		**221.11**		**1,966.81**		**4,707.14**		**1,284.34**		**3,040,870**		**128.62**		**0.03**		**51.96**	

[1] Almost all PTE calculations are performed using AP-42 emission factors except where a permit limit becomes the limiting factor. In that case, the permit limit is to be used for the emission calculation.

[2] This summary table only presents PTE results from the operating scenario when, on an annual basis, Boilers I1-I3 burn a blend of 85% natural gas and 15% fuel oil #2, Boiler I4 burns a blend of 95% natural gas and 5% landfill gas, and all turbine units burn natural gas. Boiler Units I1-I3 are permitted to burn natural gas, fuel oil #2 through #6 or equivalent (including bio-diesel), and landfill gas. Boiler Unit I4 is permitted to burn natural gas or combination of natural gas and landfill gas. For turbine units, IGT1 and IGT2 are permitted to fire or co-fire natural gas and fuel oil #2 or equivalent including bio-diesel.

[3] 8,760 hours per year is used in the PTE calculations for all operations except the operation of emergency generators for which 500 hours per year was used and of starter engines for which 146 hours per year was used.

[4] For Title V air permitting purposes, the major source threshold for a criteria air pollutant is 100 tpy and major HAPs source threshold is 10 tpy of a single HAP or 25 tpy of any HAPs combination.

V. Applicable Requirements

A. Standards addressed by the permit:

1. Pima County State Implementation Plan (SIP):

Rule 301	Planning Construction, or Operating without a Permit
Rule 302	Non-Compliance with Applicable Standards
Rule 315	Roads and Streets
Rule 316	Particulate Materials
Rule 318	Vacant Lots and Open Spaces
Rule 321	Standards and Applicability
Rule 343	Visibility Limiting Standard
Rule 344	Odor Limiting Standards

2. Code of Federal Regulations Title 40:

Part 60 Subpart KKKK	Standards of Performance for Stationary Combustion Turbines (IGT3)
Part 60 Subpart GG	Standards of Performance for Stationary Gas Turbines (IGT3)
Part 60 Appendix B	Performance Specifications
Part 63 Subpart ZZZZ	NESHAPS for Stationary Reciprocating Internal Combustion Engines
Part 63 Subpart Q	NESHAPS for Industrial Process Cooling Towers
Part 75	Continuous Emission Monitoring
Part 75 Appendix A	Specifications and Test Procedures
Part 75 Appendix B	Quality Assurance and Quality Control
Part 75 Appendix D	Optional SO_2 Emissions Data Protocol for Gas and Oil Fired Units
Part 75 Appendix F	Conversion Procedures
Part 75 Appendix G	Determination of CO_2 Emissions

3. Pima County Code (PCC) Title 17, Chapter 17.16:

17.12.060	Existing Source Emission Monitoring
17.16.020	Noncompliance with Applicable Standards
17.16.030	Odor Limiting Standards
17.16.040	Standards and Applicability (Includes NESHAP)
17.16.050	Visibility Limiting Standards
17.16.060	Fugitive Dust Producing Activities
17.16.080	Vacant Lots and Open Spaces
17.16.090	Roads and Streets
17.16.100	Particulate Materials
17.16.110	Storage Piles
17.16.130	Applicability
17.16.160	Standards of Performance for Fossil-Fuel Fired Steam Generators and General Fuel Burning Equipment
17.16.165	Standards of Performance for Fossil-Fuel Fired Industrial and Commercial Equipment
17.16.340	Standards of Performance for Stationary Rotating Machinery
17.16.430	Standards of Performance for Unclassified Sources
17.16.590	Permit Requirements for Sources Located in Attainment and Unclassifiable Areas

4. Installation Permit #1156 – October 14, 1981 by Arizona Department of Health Services (Appendix B)

B. Standards which are not applicable:

1. PSD/NSR

UNIT I4 (manufactured in 1964) was originally designed to fire natural gas and oil. This was permitted by Pima County till the early '80s. In 1980 the Department of Energy promulgated regulations that required certain large power plants to convert their operations to additionally have the capacity to burn coal. TEP applied for an installation permit for the coal conversion project. Although the initial plan was to convert all four fossil fuel-fired steam-generating units (I1 – I4), only UNIT I4 was converted. Since this change was mandated by a government order, NSR requirements are not applicable [PCC 17.16.340.A, "major modification" – c.ii & AAC R18-2-101"major modification" – c.ii].

2. Code of Federal Regulations, Title 40

a. Part 60 Subpart D Standards of Performance For Fossil Fuel Fired Steam Generators for Which Construction Commenced After August 17,1971.

b. Part 60 Subpart Da Standards of Performance For Fossil Fuel Fired Steam Generators for Which Construction Commenced After September 18, 1978.

C. Promulgated standards which will be or may be applicable not addressed by the permit:

1. 40 CFR 63, Subpart YYYY – NESHAPs for Stationary Combustion Turbines.

a. Potentially Applicable Units: IGT1, IGT2, & IGT3. Applicability includes stationary combustion turbines at major sources of HAP (63.6085).

b. The promulgation date was March 5, 2004.

c. The initial notification date was June 5, 2004.

d. The compliance date is March 5, 2007.

e. No initial notification is required for the existing turbines at TEP-Irvington.

D. Promulgated standards which will be or may be applicable after issuance of the permit that have been addressed by the permit:

1. 40 CFR 52.145(j) - Source-Specific Federal Implementation Plan for Regional Haze at H. Wilson Sundt Generating Station (TEP-IGS)

a. Applicable to Unit I4. Compliance with the NO_X, SO_2, and PM_{10} emission limitations are required by December 31, 2017.

2. 40 CFR Part 63, Subpart UUUUU – NESHAP: Coal- and Oil-Fired Electric Utility Steam Generating Units.

a. Potentially applicable units: I1, I2, & I3. The units will become subject to NESHAP 40 CFR 63 Subpart UUUUU as existing oil fired units if liquid oil is fired in the units for more than 10.0 percent of the average annual heat input during any 3 calendar years or for more than 15.0 percent of the annual heat input during any calendar year. The permit requires the Permittee to submit a permit revision if units become oil fired units in accordance with 40 CFR Part 75 and 40 CFR Part 63, Subpart UUUUU.

VI. Previous Permit Conditions

The following standards and conditions were removed from the current permit due to the coal and oil firing being discontinued in Unit I4 and otherwise not necessary [citations refer to the previous permit (See Previous Permit – Appendix C)]:

1. Section II.A.2.b Unit I4 Sulfur Dioxide Standard – For Fuel Oil Firing

2. Section II.A.5 is now streamlined in Section I of the renewal permit.

3. Section II.C standards applicable to the Auxiliary Boiler and corresponding monitoring, recordkeeping, reporting requirements. [V.C, & VI.C]

4. Section II.E standards applicable to the coal preparation plant and corresponding monitoring, recordkeeping, reporting requirements, and testing requirements. [III.B, IV.C, V.D]

5. Section II.F standards applicable to the fly ash handling systems (FAHS). [III.C, IV.D, V.E]

6. Section II.A.5.c.i.(A), (C), & (F) concerning the use of coal or fuel oil or their co-firing as fuels in Unit I4.

7. Section II.A.5.c.ii condition specifying the max sulfur content of coal fired.

8. Section III.A specifying the requirement operate a baghouse on Unit I4 to capture particulate emissions resulting from the combustion of coal fuel and the corresponding compliance assurance monitoring, recordkeeping, reporting and testing requirements as a result of Unit I4 firing coal. [IV.A.2., VI.A.1 & 2, VII.A.2].

9. Section III.D.1 & 2 relating to the Control Officers right to require additional air pollution control equipment as deemed necessary for Unit I4, the Coal Preparation Plant and Fly-Ash Handling Systems and any additional air pollution control equipment.

10. Section IV.2 Particulate Matter – Compliance Assurance Monitoring for Unit I4 (CAM)

11. Section IV.A.3 Sulfur Dioxide and Nitrogen Oxides – Unit I4;

VII. Applicability Determinations

1. No Periodic Method 9 Opacity Monitoring When Firing Gaseous Fuels.

   PDEQ has not required the Permittee to periodically monitor opacity using Method 9 methods on gaseous fuel fired boilers, turbines and other indirect heated equipment since the opacity of emissions while firing gaseous fuel is inherently low.

2. Use of Paints.

   PDEQ has determined that PCC 17.16.400.C.5 does not apply to the Permittee since facility does not meet the definition of a facility engaged in the industrial coating of miscellaneous metal parts and products under SIC Code Major Group 33 through 39.

APPENDIX A

Previous TSD Issued May 18, 2007, Revised July 13, 2010 & October 29, 2010

Tucson Electric Power
Irvington Generating Station
Air Quality Permit # 1052

TECHNICAL SUPPORT DOCUMENT (TSD)

Issued May 18, 2007, Revised July 13, 2010 & October 29, 2010

I. General Comments:

A. Company Information

1. Tucson Electric Power – Irvington Generating Station

2. Source Address: 3950 East Irvington Road, Tucson, AZ 85714.
Mailing Address: 1 South Church Ave, P.O. Box 711, Tucson, AZ 85702.

B. Background

This is a revised TSD amended to add the requirement for monitoring Mercury emissions per the ADEQ Consent Order entered into with TEP on February 18, 2009. Specific requirements can be found in the Addendum on page 30.

Tucson Electric Power – Irvington Generating Station (TEP-IGS) produces electricity by fossil fuel combustion (coal, natural gas, liquid fuel, and landfill gas). Originally, TEP-IGS did not have the capacity to fire coal and was regulated by Pima County Health Services.

However, in 1980 the Department of Energy promulgated regulations that required certain large power plants to convert their operations to additionally have the capacity to burn coal. TEP applied for and received an installation permit for the coal conversion project (see Appendix C for the Arizona Department of Health Services Installation Permit #1156). The Arizona Department of Environmental Quality (ADEQ) issued this permit and assumed oversight from Pima County (as ARS 49-402.A.4 provides original jurisdiction to the State for Coal fired electrical generating stations).

Although the initial plan was to convert all four fossil fuel-fired steam generating units (I1 – I4), only Unit I4 was converted. Since this change was mandated by a government order, NSR requirements were not applicable [PCC 17.16.340.A, "major modification" – c.ii & AAC R18-2-101 "major modification" – c.ii]. The NSPS definition for "modification" also exempts mandatory coal conversion projects [40 CFR 60.14(e)(4) and CAA Sec 111(a)(8)]. Therefore, NSPS (Subpart D) requirements are not applicable to Unit I4. This exemption also applied to the coal preparation plant as it was constructed during the coal conversion project.

In the late 1990's TEP requested that jurisdiction over TEP-IGS be returned to Pima County Department of Environmental Quality, (PDEQ); the transfer was completed shortly after ADEQ issued a 5-year Class I permit to TEP IGS (issue date July 26, 1999). PDEQ issued a significant revision on May 15, 2001 for the installation of a new, simple cycle combustion turbine to be added as a peaking unit. Via emission limitations this did not qualify as a major modification. This renewal permit is the first to be drafted and issued by PDEQ.

C. Attainment Classification

TEP-IGS is located in a region that is designated as attainment for all criteria pollutants.

II. Source Description

A. Process Description

TEP-IGS generates electricity using two fossil fuel fired processes: (1) Steam Turbine Cycle and (2) Combustion Turbine Cycle. In addition to these, there are several support facilities, some of which contain applicable requirements that are addressed by the permit.

1. Steam Turbine Cycle

There are three distinct units in this process: (1) Boiler; (2) Turbine; and (3) Generator.

a. Boiler

Water is converted to steam via combustion of fuel and heat transfer. Steam is routed to turbines while the exhaust gasses and pollutants produced during combustion are released to the ambient atmosphere after passing though air pollution controls (if required). The concentrations of pollutants released into the atmosphere depend on the fuel fired. Typical pollutants are Particulate Matter (PM), Sulfur Dioxides (SO_2), Nitrogen Oxides (NOx), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC). Specific pollutant emission rates are provided in Section IV of this document.

b. Turbine

Steam exiting the boilers enters a turbine unit. The high-pressure steam passes through rotating blades which cause the turbine shaft to rotate converting the thermal energy of the steam into mechanical energy. After passing through the turbine, the steam is sent through a condenser and is recirculated to the boiler. The only process material used by the turbine unit is steam; thus there are no emissions.

c. Generator

The turbine drives the generator which, in turn, produces electrical energy. There are no process materials and no emissions from these units.

2. Combustion Turbine Cycle

There are two distinct units in this process: (1) Combustion Turbine; and (2) Generator

a. Combustion Turbine,

Fuel and air are mixed and injected into a combustion chamber where they are ignited. The hot combustion gases pass over the turbine blades. The resulting movement of the blades causes the shaft to rotate. Exhaust gasses and pollutants produced during combustion are released to the ambient atmosphere after passing through air pollution controls (if required). Emissions resulting from combustion typically include PM, SO_2 , NOx, CO and VOC. Representative emission rates are provided in Section IV of this document.

b. Generator.

The turbine drives the generator which, in turn, produces electrical energy. There are no process materials and no emissions from these units.

3. Support Facilities

Other equipment, operations and process that function as support facilities are turbine starter engines, other smaller boilers, cooling towers, the coal preparation plant and the fly-ash handling systems. Pollutants include PM, SO_2, NOx, CO, and VOC.

B. Operating Capacity and Schedule

TEP-IGS requires the flexibility to operate 24 hours a day, 365 days a year. The net capacity of each power production unit is as follows:

1. Fossil Fuel Fired Steam Generating Units:

   a. UNIT I1 – 81.02 MW
   b. UNIT I2 – 80.53 MW
   c. UNIT I3 – 104.45 MW
   d. UNIT I4 – 156.1 MW

2. Stationary Combustion Turbines:

   a. UNIT IGT1 – 23.9 MW
   b. UNIT IGT2 – 24.5 MW
   c. UNIT IGT3 – <25 MW

C. Applicability Categories

The following categories are addressed by the permit:

1. Fossil Fuel Fired Steam Generators (Steam Turbine Cycle Boilers)

2. Stationary Rotating Machinery (Stationary Combustion Turbines & Diesel Turbine Starter Engines).

3. Auxiliary Boiler

4. Cooling Towers

5. Coal Preparation Plant & Fly-Ash Handling Systems

6. Open Areas, Roadways, & Streets

7. Alternate Operating Scenario for Stationary Rotating Machinery (Stationary Combustion Turbines & Diesel Turbine Starter Engines (IGT3)).

D. Air Pollution Control Equipment

Air Pollution Control Equipment is required for four pieces of equipment and processes: (1) UNIT I4; (2) UNIT IGT3; (3) the Coal Preparation Plant; and (4) the Fly-Ash Handling Plant.

1. UNIT I4

   The Permittee is required to install and maintain a baghouse on UNIT I4 to capture PM emissions when coal is fired (exclusively or in combination with other fuels).

2. UNIT IGT3

   Upon purchasing the unit, the Permittee is required to install and operate a water injection system or its equivalent to control NOx emissions.

3. The Coal Preparation Plant

   The Permittee is required to install and operate various enclosures, dust collectors, and other fugitive dust controls to limit PM emissions.

4. The Fly-Ash Handling Systems

   The Permittee is required to install and operate various enclosures, dust collectors, and other fugitive dust controls to limit PM emissions.

III. Regulatory History

TEP is currently in compliance with permit and regulatory requirements.

A. Testing & Inspections

Inspections have been conducted regularly since PDEQ took over jurisdiction from ADEQ. The last completed inspection was concluded in 2006.

B. Excess Emissions

There have been no Notices of Violations for any excess emissions.

IV. Emission Estimates

The following emission estimates have been carried over from previous TSDs. Actual emissions are provided by Continuous Emissions Monitoring System (CEMS) data. These values may be used for the following purposes:

(i). Ascertaining “major source” status of IGS pursuant to CAA Sec 501 (2);
(ii). Comparing source potential-to-emit with emission rates allowable by relevant standards; and
(iii). Comparing source potential-to-emit with emissions inventory and test data.

This comparison serves as a summary of existing information on emissions from TEP-IGS. These emission calculations are not meant to establish any baseline emission levels. These emission figures (except for the ALLOWABLE emissions) are not meant to be emission limitations of any form. The following tables summarize the potential to emit (PTE), allowable emissions, test results, and the emissions inventory (EI) data. The emission factors used to calculate the potential to emit are from AP-42 (1/95 ed.).

A. Fossil Fuel Fired Steam Generators

1. UNITS I1 & I2 Boilers (each)

Fuel	Pollutant	PTE (lb/hr)	PTE (TPY)	Allowable
Natural Gas	PM	4	17.5	172 lb/hr[1] (753 tpy)
	NOx	220	963.5	NA
	SOx	0.5	2.1	NA
	CO	32	140	NA
	VOC	1.4	6	NA
	THAP	0.4	1.84	NA
Co-Firing Natural Gas with Landfill Gas	PM	7	31	172 lb/hr[2] (753 tpy)
	NOx	220	963.5	NA
	SOx	3.4	15	NA
	CO	34.0	149	NA
	VOC	1.4	6	NA
	THAP	0.4	1.84	NA
Liquid Fuel (#6 Fuel Oil)	PM	61	269	172 lb/hr[3] (753 tpy)
	NOx	224	982	NA
	SOx	754	3303	1 lb SO_2/MMBtu – 3 hr average (3504 tpy)[4]
	CO	26.7	117	NA
	VOC	4.1	18	NA
	THAP	0.8	3.3	NA
Co-Firing Liquid Fuel (#6 Fuel Oil) with Landfill Gas	PM	61	269	172 lb/hr[5] (753 tpy)
	NOx	224	982	NA
	SOx	754	3303	1 lb SO_2/MMBtu – 3 hr average (3504 tpy)[6]
	CO	26.7	117	NA
	VOC	4.1	18	NA

[1] 17.16.160.C
[2] 17.16.160.C
[3] 17.16.160.C
[4] 17.16.160.D.1
[5] 17.16.160.C.
[6] 17.16.160.D.1

Fuel	Pollutant	PTE (lb/hr)	PTE (TPY)	Allowable
	THAP	0.8	3.3	NA

2. UNIT I3 Boiler

Fuel	Pollutant	PTE (lb/hr)	PTE (TPY)	Allowable
Natural Gas	PM	5.3	23	213 lb/hr[7] (933 tpy)
	NOx	287	1257	NA
	SOx	0.6	2.7	NA
	CO	41.5	182	NA
	VOC	1.8	7.8	NA
	THAP	0.54	2.37	NA
Liquid Fuel (#6 Fuel Oil)	PM	80	350	213 lb/hr[8] (933 tpy)
	NOx	292	1280	NA
	SOx	983	4307	1 lb SO_2/MMBtu – 3 hr average (3504 tpy)[9]
	CO	34.7	152	NA
	VOC	5.3	23	NA
	THAP	1.0	4.3	NA

3. UNIT I4 Boiler

Fuel	Pollutant	PTE (lb/hr)	PTE (TPY)	Allowable
Natural Gas	PM	8.5	37	311 lb/hr[10] (1362 tpy)
	NOx	468	2050	0.7 lb NO_2/MMTU – 3 hr average (5218 tpy)[11]
	SOx	1.0	4.5	1 lb SO_2/MMBtu – 3 hr average (3504 tpy)[12]
	CO	68	298	NA
	VOC	3.0	13	NA
	THAP	0.9	3.85	NA
Liquid Fuel (#6 Fuel Oil)	PM	80	350	311 lb/hr[13] (1362 tpy)

[7] 17.16.160.C
[8] 17.16.160.C
[9] 17.16.160.D.1.
[10] 17.16.160.C
[11] Installation Permit #1156 Condition 5.
[12] Installation Permit #1156 Condition 5.
[13] 17.16.160.C

Fuel	Pollutant	PTE (lb/hr)	PTE (TPY)	Allowable
	NOx	477	2090	0.7 lb NO_2/MMTU – 3 hr average (5218 tpy)[14]
	SOx	1604	7029	1 lb SO_2/MMBtu – 3 hr average (3504 tpy)[15]
	CO	56.8	249	NA
	VOC	8.0	35	NA
	THAP	1.6	7	NA
Solid Fuel (Coal)	PM	41.1	181[16]	223 lb/hr (977 tpy)[17]
	NOx	883	3866	0.7 lb NO_2/MMTU – 3 hr average (5218 tpy)[18]
	SOx	1164	5099	1 lb SO_2/MMBtu – 3 hr average (3504 tpy)[19]
	CO	30.6	134	NA
	VOC	3.7	16	NA
	THAP	15	65.7	NA

B. Stationary Rotating Machinery

1. UNITS IGT1, IGT2, & IGT3 (each, except for IGT3 see note under fuel below))

Fuel	Pollutant	PTE (lb/hr)	PTE (TPY)	Allowable
Natural Gas (UNIT IGT3 limited to natural gas exclusively, 40 tpy for NOx, SOx & VOC, 100 tpy CO and 15 tpy PM_{10}. NOx limit indirectly lows other pollutants.)	PM	7.8	34	103 lb/hr (450 tpy)[20]
	NOx	176	771	NA
	SOx	0.23	1.01	NA
	CO	43.8	192	NA
	VOC	9.6	42	NA
	THAP	0.2	0.7	NA
Liquid Fuel (#2 Fuel Oil)	PM	15	66	103 lb/hr (450 tpy)[21]
	NOx	273	1196	NA

[14] Installation Permit #1156 Condition 5.
[15] Installation Permit #1156 Condition 5.
[16] With baghouse. Without controls, 36235 tpy PM.
[17] 17.16.160.C
[18] Installation Permit #1156 Condition 5.
[19] Installation Permit #1156 Condition 5.
[20] 17.16.340.C.
[21] 17.16.340.C.

Fuel	Pollutant	PTE (lb/hr)	PTE (TPY)	Allowable
	SOx	158	692	1 lb/MMBtu (1712 tpy)[22]
	CO	18.9	83	NA
	VOC	6.6	29	NA
	THAP	1.1	5	NA

2. UNITS IGT1A, IGT2A, & IGT3A (each)

Fuel	Pollutant	PTE (lb/hr)	PTE (TPY)	Allowable
Diesel Fuel	PM	Negligible	0.02	103 lb/hr (450 tpy)[23]
	NOx	Negligible	1.1	NA
	SOx	Negligible	0.02	1 lb/MMBtu (7 tpy)[24]
	CO	Negligible	0.01	NA
	VOC	Negligible	0.03	NA
	THAP	Negligible	0.00017	NA

C. Auxiliary Boiler

Fuel	Pollutant	PTE (lb/hr)	PTE (TPY)	Allowable
Natural Gas	PM	0.5	2	28 lb/hr[25] (125 tpy)
	NOx	10	44	NA
	SOx	0.04	0.18	NA
	CO	2.6	11.4	NA
	VOC	0.4	1.8	NA
	THAP	0.04	0.17	NA
Liquid Fuel (#2 Fuel Oil)	PM	0.9	4	28 lb/hr[26] (125 tpy)
	NOx	11.0	48	NA
	SOx	30.0	131	1 lb SO_2/MMBtu – 3 hr average (320 tpy)[27]
	CO	2.7	12	NA
	VOC	0.1	0.61	NA
	THAP	0.03	0.15	NA

[22] 17.16.340.F.
[23] 17.16.340.C.
[24] 17.16.340.F.
[25] 17.16.165.C
[26] 17.16.165.C
[27] 17.16.160.E.

D. Cooling Towers

Unit	Pollutant	PTE (lb/hr)	PTE (TPY)	Allowable
I1E	PM	8.35	36	108 lb/ht (474 tpy)[28]
I2D	PM	8.35	36	108 lb/ht (474 tpy)[29]
I3D	PM	11.6	51	114 lb/ht (497 tpy)[30]
I4E	PM	16	69	119 lb/ht (521 tpy)[31]

E. Coal Preparation Plant & Fly-Ash Handling Systems

Unit	Pollutant	PTE (lb/hr)	PTE (TPY)	Allowable
Coal Preparation Plant	PM	53	232	62 lb/hr (272 tpy)[32]
Fly-Ash Handling Systems	PM	27	119	65 lb/hr (285 tpy)[33]

V. Applicable Requirements

A. Standards addressed by the permit:

1. Pima County State Implementation Plan (SIP):

Rule 315	Roads and Streets
Rule 318	Vacant Lots and Open Spaces
Rule 321	Standards and Applicability
Rule 343	Visibility Limiting Standard

2. Code of Federal Regulations Title 40:

Part 60 Subpart KKKK	Standards of Performance for Stationary Combustion Turbines (IGT3)
Part 60 Subpart GG	Standards of Performance for Stationary Gas Turbines (IGT3)
Part 60 Appendix B	Performance Specifications
Part 64	Compliance Assurance Monitoring
Part 75 Subpart F	Conversion Procedures
Part 75 Subpart G	Determination of CO Emissions
Part 75 Appendix A	Specifications and Test Procedures
Part 75 Appendix B	Quality Assurance and Quality Control

[28] PCC 17.16.430.A.1.
[29] PCC 17.16.430.A.1.
[30] PCC 17.16.430.A.1.
[31] PCC 17.16.430.A.1.
[32] PCC 17.16.310.B.2.
[33] PCC 17.16.430.A.1.

3. Pima County Code (PCC) Title 17, Chapter 17.16:

17.16.020	Noncompliance with Applicable Standards
17.16.030	Odor Limiting Standards
17.16.050	Visibility Limiting Standards
17.16.060	Fugitive Dust Producing Activities
17.16.080	Vacant Lots and Open Spaces
17.16.090	Roads and Streets
17.16.100	Particulate Materials
17.16.110	Storage Piles
17.16.130	Applicability
17.16.160	Standards of Performance for Fossil-Fuel Fired Steam Generators and General Fuel Burning Equipment
17.16.165	Standards of Performance for Fossil-Fuel Fired Industrial and Commercial Equipment
17.16.310	Standards of Performance for Coal Preparation Plants
17.16.340	Standards of Performance for Stationary Rotating Machinery
17.16.430	Standards of Performance for Unclassified Sources
17.16.590	Permit Requirements for Sources Located in Attainment and Unclassifiable Areas

4. Installation Permit #1156 – October 14, 1981 by Arizona Department of Health Services

B. Standards that are applicable, but have not been addressed by the permit:

Code of Federal Regulations Title 40:

1. Part 63 Subpart YYYY — National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines.

2. Part 63 Subpart ZZZZ — National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

These standards have not been included in this renewal permit. In an email dated 08/16/2006 TEP-IGS stated that as an existing source it is not subject to notification requirements for NESHAP Subpart ZZZZ. After reviewing the applicability requirements PDEQ has confirmed this finding. TEP-IGS has also stated that pursuant to 40 CFR 63.6090(b)(4) – (subcategories with limited requirements), none of the present turbines are subject to the notification requirements of Subpart YYYY. After reviewing the applicability requirements, it was not initially clear if the current turbines would fall into the subcategories outlined in the applicability of 40 CFR 63 Subpart YYYY. Only four subcategories are described in the applicability of subpart YYYY none of which apply to TEP-IGS. The federal register for the final rule however has 4 other subcategories and the TEP-IGS' turbines are covered under one of them. PDEQ therefore does agree that the turbines fall into the subcategory defined under 40 CFR 63.6090(b) and pursuant to 40 CFR 63.6090(b)(4), no notification is required and TEP-IGS does not have to meet the requirements of this subpart and of subpart A.

C. Standards which are not applicable:

1. PSD/NSR

UNIT I4 (manufactured in 1964) was originally designed to fire natural gas and oil. This was permitted by Pima County till the early ‘80s. In 1980 the Department of Energy promulgated regulations that required certain large power plants to convert their operations to additionally have the capacity to burn coal. TEP applied for an installation permit for the coal conversion project. Although the initial plan was to convert all four fossil fuel-fired steam-generating units (I1 – I4), only UNIT I4 was converted. Since this change was mandated by a government order, NSR requirements are not applicable [PCC 17.16.340.A, “major modification” – c.ii & AAC R18-2-101”major modification” – c.ii].

2. Code of Federal Regulations, Title 40

a. Part 60 Subpart D — Standards of Performance For Fossil Fuel Fired Steam Generators for Which Construction Commenced After August 17,1971.

b. Part 60 Subpart Da — Standards of Performance For Fossil Fuel Fired Steam Generators for Which Construction Commenced After September 18, 1978.

c. Part 60 Subpart Y — Standards of Performance for Coal Preparation Plants.

The NSPS definition for “modification” exempts mandatory coal conversion projects [40 CFR 60.14(e)(4) and CAA Sec 111(a)(8)]. Therefore, NSPS Subparts D & Da requirements are not applicable to Unit I4, nor is Subpart Y applicable to the coal preparation plant.

d. Part 60 Subpart OOO — Standards of Performance for Nonmetallic Mineral Processing Plants.

Subpart OOO specifically identifies the applicable substances of which fly-ash is not a part.

D. Promulgated standards which will be or may be applicable:

1. 40 CFR 63 Subpart DDDDD – NESHAPs for Industrial, Commercial, and Institutional Boilers and Process Heaters.

a. Applicable Unit: IAUX. Applicability includes boilers under 25 MW at Major Sources of HAP (63.7485, 63.7491(c)). TEP-IGS is a major source of HAPs (PTE: ~81.8 tpy). At 73MMBtu, this unit has a capacity of 21.4 MW.

b. The promulgation date was Sept 13, 2004.

c. The initial notification date was February 12, 2005.

d. The compliance date is Sept 13, 2007.

e. TEP submitted an initial notification on December 13, 2004.

In an email dated September 08, 2006, TEP indicated that there were no other requirements to include in the draft permit.

2. 40 CFR 63, Subpart YYYY – NESHAPs for Stationary Combustion Turbines.

   a. Potentially Applicable Units: IGT1, IGT2, & IGT3. Applicability includes stationary combustion turbines at major sources of HAP (63.6085).

   b. The promulgation date was March 5, 2004.

   c. The initial notification date was June 5, 2004.

   d. The compliance date is March 5, 2007.

   e. No initial notification is required for the existing turbines at TEP-Irvington.

3. 40 CFR 63, Subpart ZZZZ – NESHAPs for Reciprocation Internal Combustion Engines.

   a. Potentially Applicable Units: IGT1A, IGT2A, IGT3A (may be introduced with IGT3). Applicability includes stationary rotating machinery >500hp at major sources of HAP (63.6585). Emergency and Limited use units are exempt (63.6590(b)).

   b. The promulgation date was June 15, 2004.

   c. The initial notification date was September 15, 2004.

   d. The compliance date is June 15, 2007.

   e. No initial notification is required for the existing turbines at TEP-Irvington.

VI. Permit Contents

A. Applicability:

1. Fossil Fuel Fired Steam Generators - UNITS I1, I2, I3, & I4 of the previous permit – main PCC standard: 17.16.160.

2. Stationary Rotating Machinery (including Stationary Turbines) - UNITS IGT1, IGT2, IGT1A, & IGT2A of the previous permit – main PCC standard: 17.16.340.

3. Auxiliary Boiler - Unit IAUX of the previous permit – main PCC standard: 17.16.165.

4. Cooling Towers - Units I1E, I2D, I3D, & I4E of the previous permit – main PCC standard: 17.16.430.

5. Coal Preparation Plant - Coal Preparation Plant, and Emergency Coal Storage Pile of previous permit – main PCC standards: 17.16.310.

6. Fly-Ash Handling Systems - Fly-ash Handling System of previous permit – main PCC standards: 17.16.430

6. Open Areas, Roadways, & Streets – main PCC standards: 17.16.080 & 17.16.090.

7. All Operations

B. Emission Limits/ Standards:

1. Fossil Fuel Fired Steam Generators:

Citation	Applicable Units	Standard Title	Description	Discussion
II.A.1.	I1, I2, I3, & I4	Particulate Matter Standard	Hourly limit for PM emissions.	Requirement taken directly from PCC 17.16.160.C.1.
II.A.2.a.	I1, I2, & I3	Sulfur Dioxide Standard	3-hour limit for SOx emissions when firing liquid fuel.	Requirement taken directly from PCC 17.16.160.D.1
II.A.2.b.	I4	Sulfur Dioxide Standard	3-hour limit for SOx emissions regardless of fuel fired.	Preconstruction Requirement retained from Installation Permit #1156, Condition 5.
II.A.3.	I4	Nitrogen Oxides Standard	3-hour limit for NOx emissions.	Preconstruction Requirement retained from Installation Permit #1156, Condition 5.
II.A.4.	I4	Opacity Standard	Opacity limit.	Preconstruction Requirement retained from Installation Permit #1156, Condition 5.
II.A.5.a.	I1, I2, I3, & I4	Fuel Limitation	Low sulfur fuel requirement.	Requirement taken directly from PCC 17.16.160.G
II.A.5.b & c.i.	I1, I2, & I3; I4	Fuel Limitation	Allowable fuels.	17.12.190 requirement established to allow TEP-IGS to switch fuels without applying for a revision.
II.A.5.c. ii.	I4	Fuel Limitation	Coal sulfur content limitation.	Preconstruction Requirement retained from Installation Permit #1156, Condition 4.

2. Stationary Rotating Machinery (including Stationary Turbines)

Citation	Applicable Units	Standard Title	Description	Discussion
II.B.1	IGT1,2 & IGT1A,2A	Particulate Matter Standard	Hourly limit for PM emissions.	Requirement taken directly from PCC 17.16.340.C.

Citation	Applicable Units	Standard Title	Description	Discussion
II.B.2	IGT1,2 & IGT1A,2A	Sulfur Dioxide Standard	Hourly limit for SOx emissions when firing liquid fuels.	Requirement taken directly from PCC 17.16.340.F.
II.B.3	IGT1,2 & IGT1A,2A	Opacity Standard	Opacity limit.	Requirement taken directly from PCC 17.16.340.E & SIP 321.
II.B.4.a	IGT1,2 & IGT1A,2A	Fuel Limitation	Low sulfur fuel requirement.	Requirement taken directly from PCC 17.16.340.H.
II.B.4.b	IGT1 & 2	Fuel Limitation	Allowable fuels.	PCC 17.12.190 requirement established to allow TEP-IGS to switch fuels without applying for a revision.
II.B.4.c	IGT1A,2A	Fuel Limitation	Diesel fuel requirement.	PCC 17.12.190 requirement established to avoid potential issues with fuel switching.

3. Auxiliary Boiler

Citation	Applicable Units	Standard Title	Description	Discussion
II.C.1	IAUX	Particulate Matter Standard	Hourly limit for PM emissions.	Requirement taken directly from PCC 17.16.165.C.
II.C.2	IAUX	Sulfur Dioxide Standard	Hourly limit for SOx emissions when firing liquid fuel.	Requirement taken directly from PCC 17.16.165.E.
II.C.3.a	IAUX	Fuel Limitations	Low sulfur fuel requirement.	Requirement taken directly from PCC 17.16.165.G.
II.C.3.b	IAUX	Fuel Limitations	Allowable fuels.	PCC 17.12.190 requirement established to avoid potential issues with fuel switching.

4. Cooling Towers

Citation	Applicable Units	Standard Title	Description	Discussion
II.D.1	I1E, I2D, I3D, & I4E	Particulate Matter Standard	Hourly limit for PM emissions.	Requirement taken directly from PCC 17.16.430.A.1.b
II.D.2	I1E, I2D, I3D, & I4E	Odor Limiting Standard	Prohibition from emitting gasses and odor as to cause air pollution.	Requirement taken directly from PCC 17.16.430.D.
II.D.3	I1E, I2D, I3D, & I4E	Property Line	Prohibition of discharging pollutants to	Requirement taken directly from PCC 17.16.430.G.

Citation	Applicable Units	Standard Title	Description	Discussion
		Standard	adjoining property.	
II.D.4	I1E, I2D, I3D, & I4E	Chemical Limitation.	Prohibition of using chromium based water treatments.	PCC 17.12.190 requirement established to avoid 40 CFR 63 Subpart Q – Industrial Process Cooling Towers.

5. Coal Preparation Plant

Citation	Applicable Units	Standard Title	Description	Discussion
II.E.1.	CPP and associated equip	Particulate Matter Standards	Hourly limits for PM emissions.	Requirements taken directly from PCC 17.16.310.B
II.E.2	CPP and associated equip	Material Handling Standard	Handling requirements.	Requirements taken directly from PCC 17.16.100.A & 17.16.310.E.
II.E.3	CPP and associated equip	Stacking Standard	Stacking requirements.	Requirements taken directly from PCC 17.16.110.A & 17.16.310.E.
II.E.4	CPP and associated equip	Storage Pile Standards	Storage pile requirements.	Requirements taken directly from PCC 17.16.110.B & 17.16.310.E.
II.E.5	CPP and associated equip	Control Measures Standards	Control measure requirements.	Requirements taken directly from PCC 17.16.100, 17.16.110.A, & 17.16.110.B

6. Fly-Ash Handling Systems

Citation	Applicable Units	Standard Title	Description	Discussion
II.F.1.	FAHS	Particulate Matter Standards	Hourly limits for PM emissions.	Requirements taken directly from PCC 17.16.430.A.1.

7. Open Areas, Roadways, & Streets

Citation	Applicable Units	Standard Title	Description	Discussion
II.G.1	Various	Construction Limitation Standard	Control measure requirements.	Requirements taken directly from PCC 17.16.080.A & SIP 318.A.
II.G.2	Various	Cleared land	Dust suppression	Requirement taken directly from

Citation	Applicable Units	Standard Title	Description	Discussion
		Standard.	requirements.	PCC 17.16.080.B & SIP 318.B.
II.G.3	Various	Motor Vehicle Standard	Vehicular traffic limitations.	Requirement taken directly from PCC 17.16.080.C & SIP 318.C.
II.G.4	Roadways	Roadway Maintenance Standard	Roadway maintenance requirements.	Requirement taken directly from PCC 17.16.090.A.
II.G.5	Roadways	Asbestos Standard	Asbestos prohibition.	Requirement taken directly from PCC 17.16.090.F & SIP 315.

8. All Operations

Citation	Applicable Units	Standard Title	Description	Discussion
II.H.1	All units & processes	Opacity Standards	Opacity limitations.	Requirements taken directly from PCC 17.16.050.B & 17.16.130.B.3.
II.H.2	All fuel fired units	Definition of Heat Input	Heat input determination for use in other formulas.	Standard taken directly from PCC 17.16.160.B, 17.16.165.B, & 17.16.340.B.
II.H.3	All units & processes	Odor Limiting Standard	Odor limiting requirement.	Requirement taken directly from PCC 17.16.030.
II.H.4	All units & processes	Visible Emission Standard	Visible emissions requirements.	Requirement taken directly from PCC 17.16.050.D & SIP 343.

C. Air Pollution Controls:

Citation	Applicable Units	Standard Title	Description	Discussion
III.A	I4	Air Pollution Control Standard	Baghouse requirement when firing coal (PM).	Preconstruction Requirement retained from Installation Permit #1156, Condition 8.
III.B.1	Coal Prep Plant	Air Pollution Control Standard	Use of spray bars and other equipment to prevent fugitive dust	Preconstruction Requirement retained from Installation Permit #1156, Condition 7.
III.B.2	Coal Prep Plant	Air Pollution Control Standards	Minimize emissions when equipment listed is operated	Control Officer requirements for good modern practices to operate and maintain air pollution control equip.
III.C.1	Fly-Ash Handling Systems	Air Pollution Control Standards	Use of spray bars and other equipment to prevent fugitive dust	Preconstruction Requirement retained from Installation Permit #1156, Condition 7.

Citation	Applicable Units	Standard Title	Description	Discussion
III.C.2	Fly-Ash Handling Systems	Air Pollution Control Standards	Minimize emissions when equipment listed is operated	Control Officer requirements for good modern practices to operate and maintain air pollution control equip.
III.C.3, 4	Fly-Ash Handling Systems	Air Pollution Control Standards	Various pieces of equipment (PM).	Control officer requirements and Preconstruction Requirements retained from Installation Permit #1156, Conditions 10 & 11.
III.D.1	I4, CPP, FAHS	Air Pollution Control Standards	Control officer may require further controls if so deemed necessary.	Preconstruction Requirement retained from Installation Permit #1156, Condition 13.
III.D.2	Other equipment	Air Pollution Control Standards	Control officer may require further controls if so deemed necessary.	Authority from PCC 17.12.180.A.15

D. Monitoring Requirements[34]:

1. Fossil Fuel Fired Steam Generators

Citation	Applicable Units	Standard Title	Description	Discussion
IV.A1.a	I1, I2, & I3	Opacity Monitoring Standard	Weekly opacity monitoring schedule when firing liquid fuel.	PCC 17.12.180 based requirement to demonstrate compliance with II.H.1 as it pertains to Units I1, I2, & I3.
IV.A.1.b	I4	Opacity Monitoring Standard	Continuous Opacity Monitoring System requirements.	Preconstruction Requirement retained from Installation Permit #1156, Condition 6. Other pertinent standards include: 17.12.060 & 40 CFR 60 – Appendix B.
IV.A.2	I4	Compliance Assurance Monitoring	CAM Requirements.	These standards were proposed by TEP-IGS, verified by PDEQ against the requirements of 40 CFR 64.3(d) and 64.6. EPA had additional input on baghouse inspection requirements for CAM and PDEQ modified the CAM based on Appendix B Illustration No. 1a of the CAM Illustrations guidance document January 2005 Revision 1.
IV.A.3	I4	SOx, NOx Monitoring Standards	CEMS requirements for NOx &	Preconstruction Requirement retained from Installation Permit #1156, Condition 6.

[34] For ADEQ discussion on Periodic Monitoring see Appendix A.

Citation	Applicable Units	Standard Title	Description	Discussion
			SOx.	
IV.A.4	I4	Coal Monitoring Standard	Coal sampling required for each train load received.	Preconstruction Requirement retained from Installation Permit #1156, Condition 3.

2. Stationary Rotating Machinery (Including Stationary Turbines)

Citation	Applicable Units	Standard Title	Description	Discussion
IV.B.1	IGT1,2 & IGT1A,2A	Opacity Monitoring Standard	Weekly opacity monitoring schedule when firing liquid fuel.	PCC 17.12.180 based requirement to demonstrate compliance with II.B.3 & II.H.1.
IV.B.2	IGT1,2,&3	Fuel Sulfur Monitoring Standard	Sulfur content monitoring of liquid fuels.	Adapted from PCC 17.16.340.I.
IV.B.3	IGT1&2	Hours of Operation Monitoring Standard	Monthly monitoring of hours of operation.	Adopted in conjunction with testing requirements in VII.A.1.

3. Coal Preparation Plant

Citation	Applicable Units	Standard Title	Description	Discussion
IV.C.1	CPP	Opacity Monitoring Standard	Weekly opacity monitoring schedule.	Monitoring to demonstrate compliance with II.G.1 as it pertains to the CPP.
IV.C.2	CPP	Opacity Monitoring Standard	Method 9 required when excess emissions suspected.	Monitoring to demonstrate compliance with II.G.1 as it pertains to the CPP.
IV.C.3	CPP	Opacity Monitoring Standard	Required action subsequent to performing Method 9.	Monitoring to demonstrate compliance with II.G.1 as it pertains to the CPP.
IV.C.4	CPP	Opacity Monitoring Standard	Required action subsequent to performing Method 9.	Monitoring to demonstrate compliance with II.G.1 as it pertains to the CPP.

4. Fly-Ash Handling Systems

Citation	Applicable Units	Standard Title	Description	Discussion
IV.D.1	FAHS	Opacity Monitoring Standard	Weekly opacity monitoring schedule.	Monitoring to demonstrate compliance with II.G.1 as it pertains to the FAHS.
IV.D.2	FAHS	Opacity Monitoring Standard	Method 9 required when excess emissions suspected.	Monitoring to demonstrate compliance with II.G.1 as it pertains to the FAHS.
IV.D.3	FAHS	Opacity Monitoring Standard	Required action subsequent to performing Method 9.	Monitoring to demonstrate compliance with II.G.1 as it pertains to the FAHS.
IV.D.4	FAHS	Opacity Monitoring Standard	Required action subsequent to performing Method 9.	Monitoring to demonstrate compliance with II.G.1 as it pertains to the FAHS.

E. Recordkeeping Requirements:

1. Fossil Fuel Fired Steam Generators

Citation	Applicable Units	Standard Title	Description	Discussion
V.A.1	I1, I2, & I3	PM Recordkeeping Standard.	Requirement to keep records of liquid fuel specs.	Recordkeeping to demonstrate compliance with II.A.1.
V.A.2	I1, I2, & I3	SOx Recordkeeping Standard.	Requirement to records of liquid fuel specs.	Recordkeeping to demonstrate compliance with II.A.2.a. & II.A.5.a.
V.A.3	I1, I2, I3 & I4	Fuel Recordkeeping Standard.	Requirement to record fuel switching.	Recordkeeping to demonstrate compliance with II.A.5.
V.A.4	I1, I2, & I3	Hours of Operation Recordkeeping Standard.	Requirement to record hours of operation and hours during which liquid fuel is fired.	Recordkeeping to demonstrate testing requirements per VII.A.1.

2. Stationary Rotating Machinery (Including Stationary Turbines)

Citation	Applicable Units	Standard Title	Description	Discussion
V.B.1	IGT1,2,& IGT1A,2A	PM Recordkeeping Standard.	Requirement to keep records of liquid fuel specs.	Recordkeeping to demonstrate compliance with II.B.1.
V.B.2	IGT1,2,& IGT1A,2A	SOx Recordkeeping Standard.	Requirement to keep records of liquid fuel specs.	Recordkeeping to demonstrate compliance with II.B.2.

3. Auxiliary Boiler

Citation	Applicable Units	Standard Title	Description	Discussion
V.C	IAUX	Fuel Recordkeeping Standard	Requirement to keep records of changes to fuels fired.	Recordkeeping to demonstrate compliance with II.C.3.

4. Coal Preparation Plant

Citation	Applicable Units	Standard Title	Description	Discussion
V.D.1	CPP	Best Modern Practices Recordkeeping Standard	Requirement to record best modern specifications on-site.	Recordkeeping to demonstrate compliance with II.E.2, 3, 4, & 5.
V.D.2	CPP	Maintenance Recordkeeping Standard	Requirement to record maintenance actions performed on air pollution control equipment.	Recordkeeping to demonstrate compliance with III.B.

5. Fly-Ash Handling Systems

Citation	Applicable Units	Standard Title	Description	Discussion
V.E.1	FAHS	Best Modern Practices Recordkeeping Standard	Requirement to record best management specifications on-site.	Recordkeeping to demonstrate compliance with II.F.2, 3, 4, & 5.
V.E.2	FAHS	Maintenance Recordkeeping Standard	Requirement to record maintenance actions performed on air pollution control equipment.	Recordkeeping to demonstrate compliance with III.C.

6. Open Areas, Roadways, & Streets

Citation	Applicable Units	Standard Title	Description	Discussion
V.F	Various	Control Measure Recordkeeping Standard	Requirement to keep records of control measures adopted.	Recordkeeping to demonstrate compliance with II.G.1, 2 & 4.

F. Reporting Requirements:

1. Fossil Fuel Fired Steam Generators

Citation	Applicable Units	Standard Title	Description	Discussion
VI.A.1	I4	CAM Reporting Standard	Reporting required in conjunction with Compliance Assurance Monitoring.	Requirement taken from 40 CFR 64.7(d).
VI.A.2	I4	Fuel Reporting Standard	Requirement to report results of coal analyses.	Preconstruction Requirement retained from Installation Permit #1156, Condition 3.

2. Stationary Gas Turbines (Including Stationary Turbines)

Citation	Applicable Units	Standard Title	Description	Discussion
VI.B	IGT1,2 & IGT1A,2A	Fuel Reporting Standard	Reporting when sulfur content of fuels fired exceeds 0.8%.	Requirement taken directly from 17.16.340.J.

3. Auxiliary Boiler

Citation	Applicable Units	Standard Title	Description	Discussion
VI.C	IAUX	Opacity Reporting Standard	Requirement to report 6-minute periods where visible emissions exceed 15% opacity.	Requirement taken directly from PCC 17.16.165.J.

4. All Operations

Citation	Applicable Units	Standard Title	Description	Discussion
VI.D	All units & processes	Special Reporting Standard	Requirement for prompt reporting or permit deviations.	Requirement taken from PCC 17.12.180.A.5.a, A.R.S. §49-480.B, & A.A.C. 18-2-310.01.
VI.E	I4	CEMS/COMS Reporting Standard	Requirement for quarterly reporting re: CEMS/COMS.	Requirement taken from PCC 17.12.060.E.4, A.R.S. §49-480.B, & A.A.C. 18-2-310.

Citation	Applicable Units	Standard Title	Description	Discussion
VI.F	All units & processes	Semiannual Reports of Required Monitoring	Requirement for semiannual reports of all permit deviations and exceedances.	Requirement taken from PCC 17.12.180.A.5.
VI.G	All units & processes	Compliance Certification Reporting	Requirement for annual compliance certification.	Requirement taken from PCC 17.12.220.
VI.H	All units & processes	Emissions Inventory Reporting	Requirement for annual emissions inventory.	Requirement taken from PCC 17.12.320.

G. Testing Requirements[35]:

1. Fossil Fuel Fired Steam Generators

Citation	Applicable Units	Standard Title	Description	Discussion
VII.A.1	I1, I2, & I3	SOx Testing Standard	Requirement to conduct performance test on units that fire liquid fuel greater than 1300 hours per 12-month period.	Requirement carried over from previous permit to determine compliance with II.A.2.a which used 40 CFR 72.2 as a GUIDELINE. It requires units that fire liquid fuel as their primary fuel to conduct an annual performance test. These units are NOT subject to 40 CFR 72. The 1300-hour limitation comes from 72.2's definition that firing liquid fuel 15% of the time shall be considered firing liquid fuel as the primary fuel. 1300 is ~15% of 8760. The bases for this requirement are PCC 17.12.180.A.3.a & 17.12.050.
VII.A.2	I4	Criteria Emissions Testing Standard	Requirement for annual performance test for Opacity, PM, SOx, and NOx when firing coal.	Requirement carried over from previous permit to determine compliance with II.A.1, II.A.2.b, II.A.3, & II.A.4.

[35] For ADEQ discussion on Testing Requirements see Appendix A.

2. Stationary Rotating Machinery (Including Stationary Turbines)

Citation	Applicable Units	Standard Title	Description	Discussion
VII.B.1	IGT1&2	SOx Testing Standard	Requirement to conduct performance test on units that fire liquid fuel greater than 1300 hours per 12-month period.	Requirement carried over from previous permit to determine compliance with II.B.2 which used 40 CFR 72.2 as a GUIDELINE. It requires units that fire liquid fuel as their primary fuel to conduct an annual performance test. These units are NOT subject to 40 CFR 72. The 1300 hour limitation comes from 72.2's definition that firing liquid fuel 15% of the time shall be considered firing liquid fuel as the primary fuel. 1300 is ~15% of 8760. The bases for this requirement are PCC 17.12.180.A.3.a & 17.12.010.
VII.B.2	IGT1&2	CO Testing Standard	Requirement to conduct performance test on units that exceed 4500 hours in a 12-month period.	Requirement carried over from previous permit. The basis for this requirement is ARS 49-422.

3. All Operations

Citation	Applicable Units	Standard Title	Description	Discussion
VII.C	All units & processes	General Testing Standard	Requirement to contact control officer for applicable test methods when testing is required or requested.	Standard PDEQ requirement.

H. Acid Rain Permit

Citation	Applicable Units	Standard Title	Description	Discussion
II.A	I1	SOx & NOx Emission Standards	Annual limitations of respective pollutants.	Limitations taken directly from 40 CFR Part 73 Table 2.
II.B	I2	SOx & NOx Emission Standards	Annual limitations of respective pollutants.	Limitations taken directly from 40 CFR Part 73 Table 2.
II.C	I3	SOx & NOx Emission Standards	Annual limitations of respective pollutants.	Limitations taken directly from 40 CFR Part 73 Table 2.
II.D	I4	SOx & NOx Emission Standards	Annual limitations of respective pollutants.	Limitations taken directly from 40 CFR Part 73 Table 2.

I. Alternate Operating Scenario #1

Citation	Applicable Units	Standard Title	Description	Discussion
II	IGT3	Notification & Recordkeeping	Notification Requirements upon installation, startup and performance testing of unit IGT3.	Various general applicable requirements taken directly from 40 CFR 60 Subpart A and 40 CFR 60 subpart KKKK, includes notification and recordkeeping requirements for TEP-IGS to notify PDEQ concerning IGT3.
III.A	IGT3	Operational Limitation	Limited to use of natural gas.	Use of any other fuels might cause IGT3 to trigger other applicable requirements.
III.B.1.a	IGT3	Nitrogen Dioxide Standard	NOx concentration based on 4-hour rolling average.	Limitations taken directly from 40 CFR 60.4320, Table 1, 60.4325 and 60.4380.b.1.
III.B.1.b	IGT3	Nitrogen Dioxide Limitation	Annual TPY limitation on NOx.	Limitation of 40 TPY to prevent triggering a significant modification under attainment NSR.
III.B.2	IGT3	Air Pollution Control Equipment	Minimizing NOx emissions at all times	Requirements taken directly from 40 CFR 60.4333.a
III.B.3.a	IGT3	Monitoring and recordkeeping	Installation and certification of each NOx diluent CEMS.	Requirements taken directly from 40 CFR 60.4345.a
III.B.3.b	IGT3	Monitoring and recordkeeping	Demonstrate compliance with NOx concentration limitation.	Requirements taken directly from 40 CFR 60.4335

Citation	Applicable Units	Standard Title	Description	Discussion
III.B.3.c	IGT3	Monitoring and recordkeeping	Flow meter installation.	Requirements taken directly from 40 CFR 60.4345
III.B.3.d	IGT3	NOx limit monitoring	Demonstrate compliance with the 40 TPY annual limit	Authority from PCC 17.12.180.A.3, A.4 & A.5 for TEP-IGS to use CEMS to demonstrate emissions from unit are under 40 TPY and thus not trigger a significant modification under PSD.
III.B.4	IGT3	Performance Testing		Requirements taken directly from 40 CFR 60.4405, 60.4400.a
III.C.1.a	IGT3	Sulfur Dioxide Standard	Fuel sulfur content limit.	Limitations taken directly from 40 CFR 60.4365 and use of PCC 17.12.190.B.
III.C.1.b	IGT3	Sulfur Dioxide Standard	Annual TPY limitation on SO_2.	Limitation of 40 TPY to prevent triggering a significant modification under attainment NSR.
III.C.2.a	IGT3	Monitoring and recordkeeping	Demonstrate compliance with sulfur content limit	Exemption from monitoring total sulfur content of fuel if TEP-IGS keeps current records of valid purchase contract, tariff sheet or transportation contract for the fuel showing required information.
III.C.2.b	IGT3	Monitoring and recordkeeping	Demonstrate compliance with the 40 TPY annual limit	Authority from PCC 17.12.180.A.3, A.4 & A.5 for TEP-IGS to use CEMS to demonstrate emissions from unit are under 40 TPY and thus do not trigger a significant modification under attainment NSR
III.D.1	IGT3	Carbon Monoxide Standard	Annual TPY limitation on CO.	Limitation of 100 TPY to prevent triggering a significant modification under attainment NSR.
III.D.2	IGT3	Monitoring and recordkeeping	Installation and certification of CEMS for CO emissions and diluent from IGT3.	Requirements taken directly from 40 CFR 60.4345.c and use of PCC 17.12.180.A.3, A.4 & A.5 to require TEP-IGS to use CEMS to demonstrate emissions from unit are under 100 TPY and thus do not trigger a significant modification under PSD.

Citation	Applicable Units	Standard Title	Description	Discussion
III.E.1	IGT3	CEMS	Installation of CEMS	Requirements specifying how CEMS and DAHS should be installed, calibrated maintained and operated. In a meeting on 10/10/06 TEP requested that with PDEQ approval, pursuant to 40 CFR 60.4345, Procedure 1 in appendix F to this part is not required if the option to use a NOx CEMS is chosen. PDEQ approved the request to use the NOx CEMS and not Procedure 1.
III.E.2	IGT3	Monitoring recordkeeping and reporting.	Annual requirements for NOx, SO_2 and CO	Authority from PCC 17.12.180.A.3, A.4 & A.5 for TEP-IGS to follow specific procedures in demonstrating compliance with the annual limits of NOx, SO_2 and CO.

J. Alternate Operating Scenario #2

Citation	Applicable Units	Standard Title	Description	Discussion
II	IGT3	Notification & Recordkeeping	Notification Requirements upon installation, startup and performance testing of unit IGT3.	Various general applicable requirements taken directly from 40 CFR 60 Subpart A and 40 CFR 60 Subpart GG, includes notification and recordkeeping requirements for TEP-IGS to notify PDEQ concerning IGT3.
III.A	IGT3	Operational Limitation	Limited to use of natural gas.	Use of any other fuels might cause IGT3 to trigger other applicable requirements.
III.B.1.a	IGT3	Nitrogen Dioxide Standard	NOx concentration emission limit.	Limitations taken directly from 40 CFR 60.332.a.
III.B.1.b	IGT3	Nitrogen Dioxide Limitation	Annual TPY limitation on NOx.	Limitation of 40 TPY to prevent triggering a significant modification under PSD.
III.B.2	IGT3	Air Pollution Control Equipment	Minimizing NOx emissions at all times	Requirements taken directly from 40 CFR 60.11.d.

Citation	Applicable Units	Standard Title	Description	Discussion
III.B.3.a	IGT3	Monitoring and recordkeeping	Installation and certification of each NOx diluent CEMS.	Proposed requirement by TEP - IGS to install, certify, maintain and operate CEMS. Authority from 17.12.180.A.2 proposed by TEP-IGS on 10/31/06.
III.B.3.b	IGT3	Monitoring and recordkeeping	Flow meter installation.	Proposed requirement by TEP - IGS to install, certify, maintain and operate fuel flow rate monitoring system. Authority from 17.12.180.A.2 proposed by TEP-IGS on 10/31/06.
III.B.3.c	IGT3	Monitoring and recordkeeping	Demonstrate compliance with NOx concentration limitation.	Requirements taken directly from 40 CFR 60.334
III.B.3.d	IGT3	NOx limit monitoring	Demonstrate compliance with the 40 TPY annual limit	Authority from PCC 17.12.180.A.3, A.4 & A.5 for TEP-IGS to use CEMS to demonstrate emissions from unit are under 40 TPY and thus not trigger a significant modification under PSD.
III.B.4	IGT3	Performance Testing		Requirements taken directly from 40 CFR 60.4405, 60.4400.a
III.C.1.a	IGT3	Sulfur Dioxide Standard	Fuel sulfur content limit.	Limitations taken directly from 40 CFR 60.333.b and use of PCC 17.12.190.B.
III.C.1.b	IGT3	Sulfur Dioxide Standard	Annual TPY limitation on SO_2.	Limitation of 40 TPY to prevent triggering a significant modification under PSD.
III.C.2.a	IGT3	Monitoring and recordkeeping	Demonstrate compliance with sulfur content limit	Exemption from monitoring total sulfur content of fuel if TEP-IGS keeps current records of valid purchase contract, tariff sheet or transportation contract for the fuel showing required information.
III.C.2.b	IGT3	Monitoring and recordkeeping	Demonstrate compliance with the 40 TPY annual limit	Authority from PCC 17.12.180.A.3, A.4 & A.5 for TEP-IGS to use CEMS to demonstrate emissions from unit are under 40 TPY and thus do not trigger a significant modification under PSD.
III.D.1	IGT3	Carbon Monoxide Standard	Annual TPY limitation on CO.	Limitation of 100 TPY to prevent triggering a significant modification under PSD.

Citation	Applicable Units	Standard Title	Description	Discussion
III.D.2	IGT3	Monitoring and recordkeeping	Installation and certification of CEMS for CO emissions and diluent from IGT3.	Proposed requirement by TEP - IGS to install, certify, maintain and operate CEMS. Authority from 17.12.180.A.2 proposed by TEP-IGS on 10/31/06. Use of PCC 17.12.180.A.3, A.4 & A.5 to require TEP-IGS to use CEMS to demonstrate emissions from unit are under 100 TPY and thus do not trigger a significant modification under PSD.
III.E.1	IGT3	CEMS	Installation of CEMS	Requirements specifying how CEMS and DAHS should be installed, calibrated maintained and operated. Pursuant to 40 CFR 60.334 Procedure 1 in appendix F to this part is not required.
III.E.2	IGT3	Monitoring recordkeeping and reporting.	Annual requirements for NOx, SO_2 and CO	Authority from PCC 17.12.180.A.3, A.4 & A.5 for TEP-IGS to follow specific procedures in demonstrating compliance with the annual limits of NOx, SO_2 and CO.

VII. Previous Permit Conditions

The following standards were removed from the permit [citations refer to the previous permit (See Previous Permit – Appendix D)]:

A. Standards pertaining to the IGT3 NOx limitation that have been made unnecessary by the requirement to install and operate CEMS: I.C.7, III.C.2.c, d, e, f, g, h, i, j, k, l, m, & n. IV.D.9.c, and IV.E.1 & 2.

B. Standards which are not based in an applicable rule: I.D.1.

C. Standards which pertain to insignificant activities: I.I, I.L, & I.M, III.J, and III.K.

D. Standards which pertain to equipment removed from TEP-IGS: I.N, and III.L.

E. Standards which have been made unnecessary by CAM requirements: III.B.2.a.

F. Standards which reference/are based upon nonexistent permit requirements: III.D.3.

G. Requirements for IGT3 have been removed from the main permit and replaced by the Alternate Operating Scenario in Attachment G.

H. Testing for NOx on I3, CO on I1, I2 and I3 has been completed. Conditions removed were; IV.A.2 and 3. Testing for NOx and CO on IGT1 and IGT2 has been completed. Conditions removed were; IV.C. The justification is that once the initial testing was completed there was no underlying regulation to continue requiring testing for the pollutants. There is also no need to test because the current equipment is not limited to any type of emission rates for the above pollutants. TEP-IGS is a grandfathered source and unless NSR is triggered through a significant modification or other requirements specify some form of regular testing, PDEQ deems it unnecessary to require TEP-IGS to test for NOx or CO.

July 13, 2010 First Addendum to TSD Issued May 18, 2007

I. General Comments:

A. Background

Tucson Electric Power – Irvington Generating Station (TEP-IGS) produces electricity by fossil fuel combustion (coal, natural gas, liquid fuel, and landfill gas). Originally, TEP-IGS did not have the capacity to fire coal and was regulated by Pima County Health Services.

In the late 1990's TEP requested that jurisdiction over TEP-IGS be returned to Pima County Department of Environmental Quality, (PDEQ); the transfer was completed shortly after ADEQ issued a 5-year Class I permit to TEP IGS (issue date July 26, 1999). PDEQ's authority over this EUSGU and any standards adopted by ADEQ affecting EUSGUs is through a delegation agreement signed between PDEQ and ADEQ. Upon expiration of the permit, PDEQ issued the renewal permit on September 24, 2007.

B. Legal Notes

Mercury Control Consent Order

On March 15, 2005, the United States Environmental Protection Agency (EPA) promulgated the Clean Air Mercury Rule (CAMR) to address emissions of mercury from EUSGUs. CAMR applied to most EUSGUs including those at TEP-IGS. On January 29, 2007, ADEQ finalized Arizona Administrative Code (A.A.C.) R18-2-734 (State Mercury Rule) which incorporated CAMR monitoring provisions as the compliance method. On February 8, 2008, the United States Court of Appeals for the District of Columbia vacated CAMR, which created regulatory uncertainty for both ADEQ and TEP in regards to the State Mercury Rule. On February 18, 2009, ADEQ and TEP-IGS entered into a Consent Order (Docket A-15-09) which requires TEP to implement an interim mercury control strategy at TEP-IGS without interfering with TEP-IGS's ability to comply with the State Mercury Standard beginning on December 31, 2016, and the eventual Maximum Achievable Control Technology (MACT) standard that will address mercury emissions from EUSGUs. TEP-IGS's control strategy will result in an estimated minimum facility-wide annual average reduction in mercury emissions of 50 percent (or output-based emissions of 0.0087 pounds/ gigawatt-hr) during the time period of January 1, 2011 through December 31, 2015, while the State Mercury Rule would have resulted in an estimated reduction of 54 percent for the same time period. This significant revision contains an enforceable mercury reduction operation and maintenance (O&M) plan as well as a requirement to submit, by January 1, 2014, an application for another significant revision which will contain a control strategy for meeting the State Mercury Standard.

On June 22, 2009, TEP-IGS submitted a significant permit revision to incorporate provisions of the Consent Order addressing State's mercury emissions monitoring, recordkeeping and reporting provisions. .

C. Other Notes

This TSD is an addendum to the TSD issued with the 2007 renewal and only addresses the significant revision submitted for incorporation of the Consent Order standards.

D. Attainment Classification

TEP-IGS is located in a region that is designated as attainment for all criteria pollutants.

II. Source Description

A. Process Description

There are no new units being installed and no increase in emissions associated with this revision. The unit affected by is the coal-fired steam turbine cycle boiler, Unit I4. The revision incorporates mercury emissions monitoring, recordkeeping and reporting provisions.

B. Operating Schedule

This revision does not affect the operating schedule for TEP-IGS.

C. Affected Equipment

The affected equipment as discussed above is the coal-fired Unit I4.

D. Air Pollution Control Equipment

None required with this revision.

III. Regulatory History

TEP is currently in compliance with all permit and regulatory requirements.

A. Testing & Inspections

Inspections have been conducted regularly since PDEQ took over jurisdiction from ADEQ. The last completed inspection was concluded in 2006.

B. Excess Emissions

There have been no notices of violations for any excess emissions since the permit was renewed.

IV. Emission Estimates

Potential to Emit estimates are not required with this revision. Mercury potential to emit estimates are required to be submitted no later than January 31, 2014.

V. Applicable Requirements

Standards incorporated by this revision are as follows:

1. Consent Order (Docket A-15-09)

   a. Part of the language for III.B.1 was proposed by TEP-IGS. This language was obtained from the definition of operation and maintenance requirements found in 40 CFR 63.69(e)(1)(i).The language cited from there states "…At all times, including periods of startup, shutdown, and malfunction, the owner or operator must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions…" The language found in 40 CFR 63.6(e)(1)(i) shall be used to determine whether TEP-IGS is in compliance with III.B.1.

b. Mercury Control Strategy O&M Plan. The consent order requires a locally (PDEQ) enforceable O&M plan for mercury control.

c. In accordance with the Consent Order III.A.2, TEP is required to demonstrate in the significant revision application submitted that the mercury control strategy is designed to achieve a 50% reduction of total mercury emissions (based on inlet mercury) in the coal or 0.0087 lb/GWh (based on outlet mercury). The application submitted by TEP on June 22, 2009 and mercury test results submitted April 5, 2010, demonstrated that a 50% reduction of total mercury emissions is achieved. Subsequent testing to be conducted each calendar year should verify these results.

d. In accordance with the Consent Order III.A.4, TEP is required to propose a monitoring system, recordkeeping and reporting methods for determining mercury emissions from Unit I4 and for assuring that the control system is functioning in accordance with the O&M Plan. This proposal was included with the application submitted June 22, 2009.

e. Monitoring Requirements

   i. The Permittee is required to perform monthly mercury and heating value analyses for coal combusted at the facility or utilize coal samples as provided by the supplier.

   ii. The Permittee is required to determine and record for each calendar year Unit I4's annual percent reduction of mercury emissions or the output-based emissions depending upon the control strategy selected per III.A.1.a of the Consent Order.

c. Testing Requirements

   i. The Permittee is required to perform annual Method 29 (or an equivalent method approved by the Control Officer) stack tests for mercury on Unit I4 during each year in which coal-firing occurs in Unit I4.

VI. Permit Contents

1. Consent Order

The permit conditions incorporated into Attachment I of the permit are to address the requirements of the Consent Order signed between ADEQ & TEP-IGS, specifically, ADEQ Consent Order #A-15-09, Section III.A & IV.

October 29, 2010; Second Addendum to TSD Issued May 18, 2007

I. General Comments:

This TSD is an addendum to the TSD issued with the 2007 renewal and only addresses the incorporation of a minor revision submitted for installation of two emergency generators. The generators installed are one NSPS and one Non-NSPS generator.

Attainment Classification

TEP-IGS is located in a region that is designated as attainment for all criteria pollutants.

II. Source Description

A. Process Description

There are no new units being installed and no increase in emissions associated with this revision. The unit affected by is the coal-fired steam turbine cycle boiler, Unit I4. The revision incorporates mercury emissions monitoring, recordkeeping and reporting provisions.

B. Operating Schedule

This revision does not affect the operating schedule for TEP-IGS.

C. Affected Equipment

The affected equipment as discussed above is the coal-fired Unit I4.

D. Air Pollution Control Equipment

None required with this revision.

III. Regulatory History

TEP is currently in compliance with all permit and regulatory requirements.

A. Testing & Inspections

Inspections have been conducted regularly since PDEQ took over jurisdiction from ADEQ. The last completed inspection was concluded in 2006.

B. Excess Emissions

There have been no notices of violations for any excess emissions since the permit was renewed.

IV. Emission Estimates

Potential to Emit estimates are not required with this revision. No emission estimates required for emergency generators. In any case emission estimates for the two emergency generators are included in the permit application.

V. Applicable Requirements

Standards incorporated by this revision are as follows:

Emergency Generator Standards

A. Opacity Standard

1. II.A prohibits the Permittee from emitting smoke from NSPS generators in excess of 20% opacity. Cold engines exempt for the first 10 minutes.

2. II.B prohibits the Permittee from emitting smoke from non-NSPS generators in excess of 40% opacity; first 10 minutes immediately after startup are exempt from this opacity limit.

3. II.C prohibits the Permittee from emitting smoke from generators in excess of 60% opacity when engines are cold or are being accelerated under load.

4. II.D is a requirement to conduct quarterly checks of visible emissions and keep records of such inspections.

5. II.E is a provision that allows the Control Officer to require a Method 9 test conducted by the Permittee should it be necessary

B. Fuel Limitation

1. IV.A is a prohibition from firing fuels other than those allowed by the permit. This is a synthetic emission limitation for Non-NSPS engines as firing alternate fuels may result in an increase in emissions above major source thresholds. There is also a prohibition from firing fuel with a sulfur content greater than 0.9% by weight. This requirement is the basis for not requiring measures to show compliance with PCC 17.16.340.F. NSPS engines have their own requirements that have been prescribed by EPA.

2. IV.B is a requirement to maintain records of fuel specifications to demonstrate compliance with IV.A of the Attachment J.

C. NSPS Standards

1. The NSPS standards incorporated in the permit are those federal standards from 40 CFR 60, Subpart IIII that apply to emergency engines manufactured after 2007 and are contained in the NSPS Emergency Generators section in Attachment J of the permit. The NSPS engine installed by TEP-IGS was manufactured in 2008.

2. Constant speed engines are exempt from the opacity requirements of the NSPS. (TEP's NSPS generator is a constant speed engine.)

APPENDIX B

Arizona Department of Health Services Installation Permit (# 1156)

ARIZONA DEPARTMENT OF HEALTH SERVICES INSTALLATION PERMIT #1156
FOR TUCSON ELECTRIC POWER – IRVINGTON GENERATING STATION

INSTALLATION PERMIT CONDITIONS FOR
TUCSON ELECTRIC POWER COMPANY

1. Bureau of Air Quality Control personnel will be allowed to make periodic inspections, as necessary, per Arizona Code of Rules and Regulations (A.C.R.R.) R9-3-1102.

2. A monthly progress report on the construction of facilities affecting the fuel conversion shall be sent to the Department of Health Services, Bureau of Air Quality Control. When appropriate, it shall contain details on the air pollution equipment or control and changes in any other equipment or design that will affect air pollution. Construction drawings and supporting data as required by Appendix 1 of the Arizona Code of Rules and Regulations shall be furnished to the Bureau as they become available.

3. An accurate coal analysis of the sub-bituminous coal to be used at Irvington Station must be supplied to the Bureau of Air Quality Control prior to application for an operating permit for Irvington Station Unit No. 4 by an independent company or agent. Tucson Electric Power Company will continue to supply the analysis on a quarterly basis, following start-up after retrofitting Unit No. 4.

4. The maximum sulfur content of the coal shall be equal to or lress than .50 percent by weight at 10,000 BTU/lb on a three hour average basis. Regardless of heating value, SO_2 emissions shall not exceed 1.0 pound per million BTU (lb/MMBTU).

5. A visual emissions and mass emission test shall be conducted and successfully passed in accordance with the Arizona Testing Manual and with A.C.R.R. R9-3-312 and R9-3-503 prior to the granting of the operating permit. The NO_x emissions shall not exceed 0.7 lbs/MMBTU, the SO_2 emissions shall not exceed 1.0 lbs/MMBTU, and the opacity shall not exceed 20 percent. The heat input utilized in determining the allowable concentration of NO_x shall be restricted to that produced by the fuel corresponding to the NO_x emission standard selected.

6. All of the power plant stacks shall be constructed to include a continuous monitoring system, comforming to A.C.R.R. R9-3-313. The continuous monitory system shall measure the opacity, NO_x, SO_x, and either O_2 or CO_2. A permanent record of these measurements shall be kept by Tucson Electric Power Company for a period of two years and shall be made available upon request by the Bureau of Air Quality Control personnel. Excess emissions shall be reported in accordance with A.C.R.R. R9-3-314.

7. Spray bars shall be used in conjunction with other air pollution control equipment in the coal and flyash handling/storage systems to prevent fugitive dust. The conveyor belt transfer systems shall be covered and the entire system shall conform to A.C.R.R. R9-3-406 and R9-3-407.

8. Baghouses shall be kept in good repair with regularly scheduled inspections to find and replace torn bags. An inspection/maintenance schedule shall be provided to the Bureau of Air Quality Control prior to granting of the operating permit.

9. A total suspended particulates (TSP) monitor (Hi-Volume sampler) shall be installed by Tucson Electric Power Company immediately upon issuance of this installation permit on a site approved by the Bureau of Air Quality Control for the purposes of monitoring fugitive emissions from the construction phase of the coal conversion project and fugitive coal and flyash emissions. The sampling shall follow the BAQC-approved six-day schedule and a monthly data report shall be forwarded to the Bureau of Air Quality Control by the 15th of each succeeding month.

10. The loading sleeve on the flyash hopper shall incorporate a cut-off valve. (This valve is listed as optional by the manufacturer). Flyash shall be wetter prior to any handling in an open area. In order to prevent air pollution, the flyash handling area shall be paved, preferably with concrete, and the haul road to the yard disposal area shall also be paved. The haul road shall be temporarily stabilized with a dust suppressant acceptable to the Director of the Arizona Department of Health Services prior to completion of construction.

11. The flyash shall be loaded into enclosed hopper trucks through a closed gravity feed system and the outer sleeve of the dual sleeve system shall seal with the loading port of the truck and it shall be vented back to the hopper baghouse.

12. Except for short-term fuel switching (three hours or less), alternate fuels shall <u>not</u> be fired simultaneously.

13. The Director of Health Services reserves the right to require any additional air pollution control equipment as deemed necessary.

ARIZONA DEPARTMENT OF HEALTH SERVICES

Office of the Director

.E BABBITT, Governor
JAMES E. SARN, M.D., M.P.H., Director

November 10, 1981

Mr. Thomas Via, Vice President
Tucson Electric Power Company
P. O. Box 711
Tucson, Arizona 85702

Dear Mr. Via:

We are pleased to enclose the installation permit covering the conversion of the Irvington Generating Station from gas and oil fuels to a bituminous coal fuel. This permit with its conditions is being granted in accordance with A.C.R.R. R9-3-301 and must be completely satisfied before an operating permit can be issued. While the conversion is being carried out as required by a prohibition order from the U. S. Department of Energy which exempts the requirements for the prevention of significant deterioration in an attainment area, the conversion must still meet the ambient air quality regulations of Arizona.

Considering that it is the prime responsibility of this Department to control present and future sources of emissions in a manner that insures the health, safety and general welfare of the public, there is a certain degree of apprehension on our part regarding the marginal attainment of standards. This concern has been expressed previously and, for your information, enclosed is a fact sheet reiterating the areas of concern. As you can see, particulate matter does not appear to be a problem since your applied controls result in an emission rate well below the State limit. This is most gratifying in view of the station being located within a nonattainment area for total suspended particulates.

The uncontrolled emission rate of sulfur dioxide, however, is very close to the State limit and presents a possible problem since this particular emission is occurring in an attainment area for this pollutant. The concern here, of course, is that an inability to meet the required limit could result in a need for considering necessary control equipment.

Similarly, the controlled emission rate of oxides of nitrogen is practically equivalent to the State limit. It poses a critical concern for coal conversion which might produce a "brown cloud" of pollution over Tucson. Because of this possibility, it becomes extremely important that the modifications to the boilers be designed to minimize these emissions.

In addition, calculations indicate the possibility on certain days of a 10 percent reduction in visibility for the Tucson area due mainly to sulfates generated from burning coal at the Irvington Station.

Mr. Thomas Via, Vice President

Page Two.

In keeping with our concerns, we wish to emphasize the need for an effective monitoring program as required by the conditions of the installation permit.

Your cooperation is appreciated and we look forward to working with you in the best interests of the conversion satisfying air quality standards.

Sincerely,

James E. Sarn, M.D., M.P.H.
Director

JES:AAA:db

Enclosures

cc: J. Wesley Clayton, Ph.D., Assistant Director
Arthur A. Aymar, P.E., Chief, Bureau of Air Quality Control

TUCSON ELECTRIC POWER COAL CONVERSION FACT SHEET

A. TOTAL EMISSIONS (Using AP-42)

	Uncontrolled (t/yr)	Controlled (t/yr)
PM	123,400	247
SO_2	11,932	---
CO	628	---
HC	188	---
NO_x	18,840	12,686*

* Includes tangential firing as a control. No other controls are included.

B. EMISSION RATES (Using AP-42)

	Uncontrolled	Controlled	State Limit
PM	28174 lbs/hr	56.4 lbs/hr	465 lbs/hr
SO_2	.95 lbs/MMBTU**	---	1.0 lb/MMBTU
CO	.05 lbs/MMBTU	---	---
HC	.02 lbs/MMBTU	---	---
NO_x	1.5 lbs/MMBTU	.69 lbs/MMBTU*	.7 lbs/MMBTU

* Tucson Electric Power's (TEP) estimate of NO_x emissions. The BAQC cannot disagree. but our best estimate is less than 1.01 lbs/MMBTU when all four units are using coal. However, the estimate did not include all of the controls.

**Based on a heat input of 10,000 BTU/lb coal and a .5% sulfur in the coal.

C. CONCENTRATION (Using TEP's Environmental Assessment)

1. Long Term

	3hr($\mu g/m^3$)	24hr($\mu g/m^3$)	Annual	Increase in 24hr($\mu g/m^3$)	De Minimus($\mu g/m^3$)
PM	---	11.3	2	7.4	10(24 hr)
SO_2	493	115	21.9	75.2	13(24 hr)
NO_x	NA	NA *	12.5	40.0	14(24 hr)

* NO_x values were greatly underestimated; nevertheless, using an approximate 5:1 ratio (24 hr:annual) found in actual data, the De Minimus is exceeded.

2. Short-Term (From letter MS:GRN:133-81 & TEP's Environmental Assessment)

Relative Maximum Predicted

	Coal($\mu g/m^3$)	1979 Oil/Gas($\mu g/m^3$)
PM	10.8	12
SO_2	504	124
NO_x	465	306

D. VISIBILITY

The staff meteorologist gives a rough estimate of a 10 percent reduction in visibility for the Tucson area, due mainly to sulfates generated from burning coal at the Irvington Station.

RIZONA DEPARTMENT OF HEALTH SERVICI
DIVISION OF ENVIRC..MENTAL HEALTH SERVICES ■ BUREAU OF ..R QUALITY CONTROL
1740 West Adams Street ■ Phoenix, AZ 85007 ■ Phone (602)255-1144

INSTALLATION PERMIT

(As required by Section 36-1707.01, Arizona Revised Statutes)

1. PERMIT TO BE ISSUED TO (Business License Name of Organization that is to receive permit)
Tucson Electric Power Company

2. NAME (OR NAMES) OF OWNER OR PRINCIPALS DOING BUSINESS AS THE ABOVE ORGANIZATION
J. Thomas Via, Jr., Vice President

3. MAILING ADDRESS Post Office Box 711
NUMBER STREET
Tucson, Arizona 85726
CITY OR COMMUNITY STATE ZIP CODE

4. EQUIPMENT LOCATION ADDRESS 4350 East Irvington Road
NUMBER STREET
Tucson, Arizona 85726
CITY OR COMMUNITY STATE ZIP CODE

5. FACILITIES OR EQUIPMENT DESCRIPTION Retrofit of Units 1, 2, 3, and 4 of Irvington Generating Station, installation of baghouses, increase stack height to 248 feet installation of coal and flyash handling/storage facilities, and associated equipment.

6. THIS PERMIT ISSUED SUBJECT TO THE FOLLOWING See Attachment "1"

7. ADHS PERMIT NUMBER 1156 PERMIT CLASS A

ISSUED THIS 14th DAY OF October, 19 81

SIGNATURE Director
TITLE

The issuance of this permit shall in now way be construed as a warranty affirmation or indication that the equipment described herein will quality for an operating permit. It is the sole responsibility of the applicant to comply with all applicable air pollution laws, regulations and standards.

ADHS/EHS/Air Quality-100C (Rev. 12-80)

INSTALLATION PERMIT CONDITIONS FOR
TUCSON ELECTRIC POWER COMPANY

1. Bureau of Air Quality Control personnel will be allowed to make periodic inspections, as necessary, per Arizona Code of Rules and Regulations (A.C.R.R.) R9-3-1102.

2. A monthly progress report on the construction of facilities affecting the fuel conversion shall be sent to the Department of Health Services, Bureau of Air Quality Control. When appropriate, it shall contain details on the air pollution equipment or controls and changes in any other equipment or design that will affect air pollution. Construction drawings and supporting data as required by Appendix 1 of the Arizona Code of Rules and Regulations shall be furnished to the Bureau as they become available.

3. An accurate coal analysis of the sub-bituminous coal to be used at Irvington Station must be supplied to the Bureau of Air Quality Control prior to application for an operating permit for Irvington Station Unit No. 4 by an independent company or agent. Tucson Electric Power Company will continue to supply the analysis on a quarterly basis, following start-up after retrofitting Unit No. 4.

4. The maximum sulfur content of the coal shall be equal to or less than .50 percent by weight at 10,000 BTU/lb on a three hour average basis. Regardless of heating value, SO_2 emissions shall not exceed 1.0 pound per million BTU (lb/MMBTU).

5. A visual emissions and mass emissions test shall be conducted and successfully passed in accordance with the Arizona Testing Manual and with A.C.R.R. R9-3-312 and R9-3-503 prior to the granting of the operating permit. The NO_x emissions shall not exceed 0.7 lbs/MMBTU, the SO_2 emissions shall not exceed 1.0 lbs/MMBTU, and the opacity shall not exceed 20 percent. The heat input utilized in determining the allowable concentration of NO_x shall be restricted to that produced by the fuel corresponding to the NO_x emission standard selected.

6. All of the power plant stacks shall be constructed to include a continuous monitoring system, conforming to A.C.R.R. R9-3-313. The continuous monitoring system shall measure the opacity, NO_x, SO_x, and either O_2 or CO_2. A permanent record of these measurements shall be kept by Tucson Electric Power Company for a period of two years and shall be made available upon request by the Bureau of Air Quality Control personnel. Excess emissions shall be reported in accordance with A.C.R.R. R9-3-314.

7. Spray bars shall be used in conjunction with other air pollution control equipment in the coal and flyash handling/storage systems to prevent fugitive dust. The conveyor belt transfer systems shall be covered and the entire system shall conform to A.C.R.R. R9-3-406 and R9-3-407.

8. Baghouses shall be kept in good repair with regularly scheduled inspections to find and replace torn bags. An inspection/maintenance schedule shall be provided to the Bureau of Air Quality Control prior to granting of the operating permit.

9. A total suspended particulates (TSP) monitor (Hi-Volume sampler) shall be installed by Tucson Electric Power Company immediately upon issuance of this installation permit on a site approved by the Bureau of Air Quality Control for the purposes of monitoring fugitive emissions from the construction phase of the coal conversion project and fugitive coal and flyash emissions. The sampling shall follow the BAQC-approved six-day schedule and a monthly data report shall be forwarded to the Bureau of Air Quality Control by the 15th of each succeeding month.

10. The loading sleeve on the flyash hopper shall incorporate a cut-off valve. (This valve is listed as optional by the manufacturer). Flyash shall be wetted prior to any handling in an open area. In order to prevent air pollution, the flyash handling area shall be paved, preferably with concrete, and the haul road to the yard disposal area shall also be paved. The haul

road shall be temporarily stabilized with a dust suppressant acceptable to the Director of the Arizona Department of Health Services prior to completion of construction.

11. The flyash shall be loaded into enclosed hopper trucks through a closed gravity feed system and the outer sleeve of the dual sleeve system shall seal with the loading port of the truck and it shall be vented back to the hopper baghouse.

12. Except for short-term fuel switching (three hours or less), alternate fuels shall <u>not</u> be fired simultaneously.

13. The Director of Health Services reserves the right to require any additional air pollution control equipment as deemed necessary.

APPENDIX C

Current Air Quality Permit #1052

PIMA COUNTY DEPARTMENT OF ENVIRONMENTAL QUALITY
Air Program

33 North Stone Avenue, Suite 700, Tucson, AZ 85701, Phone: (520) 243-7400

AIR QUALITY OPERATING PERMIT
(As required by Title 17.12, Article II, Pima County Code)

ISSUED TO

TUCSON ELECTRIC POWER
IRVINGTON GENERATING STATION
3950 EAST IRVINGTON ROAD
TUCSON, AZ 85714

This air quality operating permit does not relieve applicant of responsibility for meeting all air pollution regulations

THIS PERMIT ISSUED SUBJECT TO THE FOLLOWING: **Conditions contained in Parts A, B AND Attachments C, D, E, F, G & H.**

PDEQ PERMIT NUMBER **1052** PERMIT CLASS **I**

ISSUED: **SEPTEMBER 24, 2007** REVISED: **JULY 13 & OCTOBER 29, 2010**

EXPIRES: **SEPTEMBER 23, 2012**

Mukonde Chama, P.E., Air Permits Supervisor, PDEQ

SIGNATURE TITLE

Tucson Electric Power
Irvington Generating Station

TABLE OF CONTENTS

Tucson Electric Power
Irvington Generating Station
Air Quality Permit # 1052

SUMMARY

This operating permit is the first 5-year air quality permit issued by the Pima County Department of Environmental Quality (PDEQ) to Tucson Electric Power – Irvington Generating Station, (TEP-IGS), the Permittee. The permit was revised in April 2010 to include the mercury emission monitoring standards. The facility is a major source of all criteria pollutants as well as individual and combined HAPs. The facility is a stationary source which generates electricity and consists primarily of fossil-fuel fired steam generating units (boilers) and stationary combustion turbines as well as engines, cooling towers, and other processes and equipment associated with power production and delivery as well as fuel preparation and transfer.

The Permittee previously operated under an air quality permit issued by the Arizona Department of Environmental Quality, (ADEQ). In 2001 permitting authority for TEP-IGS was transferred from ADEQ to PDEQ.

TEP-IGS is subject to Title V permitting requirements, Standards of Performance for Stationary Combustion Turbines (40 CFR 60 Subpart GG or Subpart KKKK for Unit IGT3), Compliance Assurance Monitoring (40 CFR 64), ADEQ-TEP Consent Order dated February 17, 2009 and the Acid Rain Program of the Clean Air Act (40 CFR 72-80).

All terms and conditions of this permit are federally enforceable by the Administrator of the United States Environmental Protection Agency (U.S.EPA) under the Clean Air Act, except as otherwise noted.

PART A: GENERAL PROVISIONS

(References to A.R.S. are references to the Arizona Revised Statutes, references to A.A.C. are references to the Arizona Administrative Code, and references to PCC are references to Title 17 of the Pima County Code)

I. PERMIT EXPIRATION AND RENEWAL [PCC 17.12.180.A.1 & PCC 17.12.160.C.2]

A. This permit is valid for a period of five years from the date of issuance of the permit.

B. The Permittee shall submit an application for renewal of this permit at least 6 months, but not greater than 18 months prior to the date of permit expiration.

II. COMPLIANCE WITH PERMIT CONDITIONS [PCC 17.12.180.A.8.a & b]

A. The Permittee shall comply with all conditions of this permit including all applicable requirements of Arizona air quality statutes A.R.S. Title 49, Chapter 3, and Pima County air quality rules. Any permit noncompliance is grounds for enforcement action; for permit termination, revocation and reissuance, or revision; or for denial of a permit renewal application. In addition, noncompliance with any federally enforceable requirement constitutes a violation of the Clean Air Act..

B. 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 in order to maintain compliance with the conditions of this permit.

III. PERMIT REVISION, REOPENING, REVOCATION AND REISSUANCE, OR TERMINATION FOR CAUSE [PCC 17.12.180.A.8.c & PCC 17.12.270]

A. The permit may be revised, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee for a permit revision, revocation and reissuance, or termination; or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

B. The permit shall be reopened and revised under any of the following circumstances:

1. Additional applicable requirements under the Act become applicable to a major source. Such reopening shall only occur if there are three or more years remaining in the permit term. The reopening shall be completed not later than 18 months after promulgation of the applicable requirement. No such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to PCC 17.12.280. Any permit reopening required pursuant to this paragraph shall comply with provisions in PCC 17.12.280 for permit renewal and shall reset the five-year permit term.

2. Additional requirements, including excess emissions requirements, become applicable to an affected source under the acid rain program. Upon approval by the Administrator, excess emissions offset plans shall be deemed to be incorporated into the Class I permit.

3. The Control Officer or the Administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emissions standards or other terms or conditions of the permit.

4. The Control Officer or the Administrator determines that the permit needs to be revised or revoked to assure compliance with the applicable requirements.

C. Proceedings to reopen and issue a permit, including appeal of any final action relating to a permit reopening, shall follow the same procedures as apply to initial permit issuance. Such reopenings shall be made as expeditiously as practicable. Permit reopenings for reasons other than those stated in paragraph III.B.1 of Part A shall not result in the resetting of the five-year permit term.

IV. POSTING OF PERMIT [PCC 17.12.080]

The Permittee who has been granted an individual permit by PDEQ or a general permit by ADEQ shall maintain a complete copy of the permit onsite. If it is not feasible to maintain a copy of the permit onsite, the permittee may request, in writing, to maintain a copy of the permit at an alternate location. Upon written approval by the Control Officer, the permittee must maintain a complete copy of the permit at the approved alternative location.

V. FEE PAYMENT [PCC 17.12.180.A.9 & PCC 17.12.510]

Permittee shall pay fees to the Control Officer pursuant to PCC 17.12.510.

VI. ANNUAL EMISSIONS INVENTORY QUESTIONNAIRE [PCC 17.12.320]

A. When requested by the Control Officer, the Permittee shall complete and submit an annual emissions inventory questionnaire. The questionnaire is due by March 31 or ninety days after the Control Officer makes the request and provides the inventory form each year, whichever occurs later, and shall include emission information for the previous calendar year These requirements apply whether or not a permit has been issued and whether or not a permit application has been filed.

B. The questionnaire shall be on a form provided by or approved by the Control Officer and shall include the information required by PCC 17.12.320.

VII. COMPLIANCE CERTIFICATION [PCC 17.12.180.A.5 & PCC 17.12.220.A.2]

The Permittee shall submit to the Control Officer a compliance certification that describes the compliance status of the source with respect to each permit condition. Certifications shall be submitted as specified in Part B of this permit.

A. The compliance certification shall include the following:

1. Identification of each term or condition contained in the permit including emission limitations, standards, or work practices that are the basis of the certification;

2. Identification of the method(s) or other means used by the Permittee for determining the compliance status of the source with each term and condition during the certification period. Such methods and other means shall include, at a minimum, the methods and means required under the monitoring, related recordkeeping and reporting sections of this permit. If necessary, the owner or operator also shall identify any other material information that must be included in the certification to comply with Section 113(c)(2) of the Clean Air Act, which prohibits knowingly making a false certification or omitting material information.;

3. The status of compliance with the terms and conditions of the permit for the period covered by the certification, including whether compliance during the period was continuous or intermittent. The certification shall identify each deviation and take it into account in the compliance certification;

4. For emission units subject to 40 CFR 64, the certification shall also identify as possible exceptions to compliance any period during which compliance is required and in which an excursion or exceedance defined under 40 CFR 64 occurred;

5. A progress report on all outstanding compliance schedules submitted pursuant to PCC 17.12.220; and

6. Other facts the Control Officer may require to determine the compliance status of the facility.

B. A copy of all compliance certifications for Class I permits shall also be submitted to the EPA Administrator. The address for the EPA administrator is:

EPA Region 9 Enforcement Office, 75 Hawthorne St (Air-5), San Francisco, CA 94105

VIII. CERTIFICATION OF TRUTH, ACCURACY AND COMPLETENESS [PCC 17.12.220.A.3]

Any document required to be submitted by this permit, including reports, shall contain a certification by a responsible official of truth, accuracy, and completeness. This certification and any other certification required by this permit shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

IX. INSPECTION AND ENTRY [PCC 17.12.220.A.4]

The Permittee shall allow the Control Officer or the authorized representative of the Control Officer upon presentation of proper credentials to:

A. Enter upon the Permittee's premises where a source is located or emissions-related activity is conducted, or where records are required to be kept under the conditions of the permit;

B. Have access to and copy, at reasonable times, any records that are required to be kept under the conditions of the permit;

C. Inspect, at reasonable times, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit;

D. Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with the permit or other applicable requirements; and

E. Record any inspection by use of written, electronic, magnetic and photographic media.

X. PERMIT REVISION PURSUANT TO FEDERAL HAZARDOUS AIR POLLUTANT STANDARD [PCC 17.12.160.D.3]

If this source becomes subject to a standard promulgated by the Administrator pursuant to section 112(d) of the Act, then the Permittee shall, within twelve months of the date on which the standard is promulgated, submit an application for a permit revision demonstrating how the source will comply with the standard.

XI EXCESS EMISSIONS, PERMIT DEVIATIONS, AND EMERGENCY REPORTING [PCC 17.12.040]

A. Excess Emissions Reporting [PCC 17.12.040]

1. Excess emissions shall be reported as follows:

a. The permittee shall report to the Control Officer any emissions in excess of the limits established by this permit. The report shall be in 2 parts as specified below:

i. Notification by telephone or facsimile within 24 hours of the time the permittee first learned of the occurrence of excess emission that includes all available information from 17.12.040.B. The number to call to report excess emissions is **520-243-7400.** The facsimile number to report excess emissions is **520-243-7370.**

ii. Detailed written notification by submission of an excess emissions report within 72 hours of the notification under XI.A.1.a.i of Part A above. Notifications should be sent to:

PDEQ Air Program 33 N. Stone Avenue, Suite 700 Tucson, Arizona 85701.

b. The excess emission report shall contain the following information:

i. The identity of each stack or other emission point where the excess emission occurred;

ii. The magnitude of the excess emissions expressed in the units of the applicable emission limitation and the operating data and calculations used in determining the magnitude of the excess emissions;

iii. The time and duration or expected duration of the excess emissions;

iv. The identity of the equipment from which the excess emissions emanated;

v. The nature and cause of the emissions;

vi. The steps taken, if the excess emissions were the result of a malfunction, to remedy the malfunction and the steps taken or planned to prevent the recurrence of the malfunctions;

vii. The steps that were or are being taken to limit the excess emissions; If the source's permit contains procedures governing source operation during periods of startup or malfunction and the excess emissions resulted from startup or malfunction, a list of the steps taken to comply with the permit procedures.

2. In the case of continuous or recurring excess emissions, the notification requirements of this Section shall be satisfied if the source provides the required notification after excess emissions are first detected and includes in the notification an estimate of the time the excess emissions will continue. Excess emissions occurring after the estimated time period or changes in the nature of the emissions as originally reported shall require additional notification pursuant to XI.A.1.a & b of Part A above.

B. Permit Deviations Reporting [PCC 17.12.180.A.5.b]

The Permittee shall promptly report deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. Notice in accordance with 17.12.180.E.3.d shall be considered prompt for purposes of this permit.

C. Emergency Provision [PCC 17.12.180.E]

1. An "Emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, that requires immediate corrective action to restore normal operation and that causes the source to exceed a technology-based emission limitation under the permit, due to unavoidable increases in emission attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventive maintenance, careless or improper operation, or operator error.

2. An emergency constitutes an affirmative defense to an action brought for noncompliance with the technology-based emission limitations if the conditions of PCC 17.12.180.E.3 are met.

3. The affirmative defense of emergency shall be demonstrated through properly signed, contemporaneous operating logs, or other relevant evidence that:

a. An emergency occurred and that the permittee can identify the cause or causes of the emergency;

b. At the time of the emergency, the permitted facility was being properly operated;

c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emissions standards or other requirements in the permit; and

d. The Permittee submitted notice of the emergency to the Control Officer by certified mail, hand delivery or facsimile transmission within two working days of the time when emission limitations were exceeded due to the emergency. This notice shall contain a description of the emergency, any steps taken to mitigate emissions, and corrective action taken.

4. In any enforcement proceeding, the permittee seeking to establish the occurrence of an emergency has the burden of proof.

5. This provision is in addition to any emergency or upset provision contained in any applicable requirement.

D. Compliance Schedule [ARS § 49-480.F.3 & 5]

For any excess emission or permit deviation that cannot be corrected within 72 hours, the permittee is required to submit a compliance schedule to the Director within 21 days of such occurrence. The compliance schedule shall include a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with the permit terms or conditions that have been violated.

E. Affirmative Defenses for Excess Emissions Due to Malfunctions, Startup, and Shutdown. [PCC 17.12.035]

1. Applicability

This rule establishes affirmative defenses for certain emissions in excess of an emission standard or limitation and applies to all emission standards or limitations except for standards or limitations:

a. Promulgated pursuant to Sections 111 or 112 of the Act,

b. Promulgated pursuant to Titles IV or VI of the Clean Air Act,

c. Contained in any Prevention of Significant Deterioration (PSD) or New Source Review (NSR) permit issued by the U.S. E.P.A., or

d. Included in a permit to meet the requirements of PCC 17.16.590.A.5.

2. Affirmative Defense for Malfunctions

Emissions in excess of an applicable emission limitation due to malfunction shall constitute a violation. The owner or operator of a source with emissions in excess of an applicable emission limitation due to malfunction has an affirmative defense to a civil or administrative enforcement proceeding based on that violation, other than a judicial action seeking injunctive relief, if the owner or operator of the source has complied with the reporting requirements of XIII.B of this Part and has demonstrated all of the following:

a. The excess emissions resulted from a sudden and unavoidable breakdown of process equipment or air pollution control equipment beyond the reasonable control of the operator;

b. The air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions;

c. If repairs were required, the repairs were made in an expeditious fashion when the applicable emission limitations were being exceeded. Off-shift labor and overtime were utilized where practicable to ensure that the repairs were made as expeditiously as possible. If off-shift labor and overtime were not utilized, the owner or operator satisfactorily demonstrated that the measures were impracticable;

d. The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable during periods of such emissions;

e. All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality;

f. The excess emissions were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

g. During the period of excess emissions there were no exceedances of the relevant ambient air quality standards established in PCC Chapter 17.08 that could be attributed to the emitting source;

h. The excess emissions did not stem from any activity or event that could have been foreseen and avoided, or planned, and could not have been avoided by better operations and maintenance practices;

i. All emissions monitoring systems were kept in operation if at all practicable; and

j. The owner or operator's actions in response to the excess emissions were documented by contemporaneous records.

3. Affirmative Defense for Startup and Shutdown

a. Except as provided in XI.E.3.b of Part A, and unless otherwise provided for in the applicable requirement, emissions in excess of an applicable emission limitation due to startup and shutdown shall constitute a violation. The owner or operator of a source with emissions in excess of an applicable emission limitation due to startup and shutdown has an affirmative defense to a civil or administrative enforcement proceeding based on that violation, other than a judicial action seeking injunctive relief, if the owner or operator of the source has complied with the reporting requirements of XIII.B of Part A and has demonstrated all of the following:

i. The excess emissions could not have been prevented through careful and prudent planning and design;

ii. If the excess emissions were the result of a bypass of control equipment, the bypass was unavoidable to prevent loss of life, personal injury, or severe damage to air pollution control equipment, production equipment, or other property;

iii. The source's air pollution control equipment, process equipment, or processes were at all times maintained and operated in a manner consistent with good practice for minimizing emissions;

iv. The amount and duration of the excess emissions (including any bypass operation) were minimized to the maximum extent practicable during periods of such emissions;

v. All reasonable steps were taken to minimize the impact of the excess emissions on ambient air quality;

vi. During the period of excess emissions there were no exceedances of the relevant ambient air quality standards established in PCC Chapter 17.08 that could be attributed to the emitting source;

vii. All emissions monitoring systems were kept in operation if at all practicable; and

viii. The Permittee's actions in response to the excess emissions were documented by contemporaneous records.

b. If excess emissions occur due to a malfunction during routine startup and shutdown, then those instances shall be treated as other malfunctions subject to XI.E.2 of this Part A.

4. Affirmative Defense for Malfunctions during Scheduled Maintenance

If excess emissions occur due to a malfunction during scheduled maintenance, then those instances will be treated as other malfunctions subject to XI.E.2 of Part A.

5. Demonstration of Reasonable and Practicable Measures

For an affirmative defense under XI.E.2 or 3 of Part A, the Permittee of the source shall demonstrate, through submission of the data and information required by XI.E.1 – 5 and XII.B of Part A, that all reasonable and practicable measures within the owner or operator's control were implemented to prevent the occurrence of the excess emissions.

XII. RECORD KEEPING REQUIREMENTS [PCC 17.12.180.A.4]

A. Permittee shall keep records of all required monitoring information including, recordkeeping requirements established pursuant to PCC 17.12.190, where applicable, for the following:

1. The date, place as defined in the permit, and time of sampling or measurements;

2. The date(s) analyses were performed;

3. The name of the company or entity that performed the analyses;

4. A description of the analytical techniques or methods used;

5. The results of such analyses; and

6. The operating conditions as existing at the time of sampling or measurement.

B. The Permittee shall retain records of all required monitoring data and support information for a period of at least 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 the permit.

C. All required records shall be maintained either in an unchangeable electronic format or in a handwritten log utilizing indelible ink.

XIII. REPORTING REQUIREMENTS [PCC 17.12.180.A.5]

The Permittee shall comply with all of the reporting requirements of this permit. These include all of the following:

A. Compliance certifications pursuant to VII of this Part.

B. Excess emission; permit deviation, and emergency reports in accordance with XI of this Part.

C. Performance test results in accordance with XVII.F of this Part.

D. Reporting requirements listed in Part B of this permit.

XIV. DUTY TO PROVIDE INFORMATION [PCC 17.12.180.A.8.e, PCC 17.12.160.G, & PCC 17.12.160.H]

A. The Permittee shall furnish to the Control Officer, within a reasonable time, any information that the Control Officer may request in writing to determine whether cause exists for revising, revoking and reissuing, or terminating the permit or to determine compliance with the permit. Upon request, the Permittee shall also furnish to the Control Officer copies of records required to be kept by the permit. For information claimed to be confidential, the Permittee, for Class I sources, shall furnish an additional copy of such records directly to the Administrator along with a claim of confidentiality.

B. If the Permittee has failed to submit any relevant facts or if the Permittee has submitted incorrect information in the permit application, the Permittee shall, upon becoming aware of such failure or incorrect submittal, promptly submit such supplementary facts or corrected information. In addition, an applicant shall provide additional information as necessary to address any requirements that become applicable to the source after the date it filed a complete application but prior to release of a proposed permit.

XV. PERMIT AMENDMENT OR REVISION [PCC 17.12.245, PCC 17.12.255 & PCC 17.12.260]

Permittee shall apply for a permit amendment or revision for changes to the facility which do not qualify for a facility change without revision under XVI of Part A, as follows:

A. Administrative Permit Amendment (PCC 17.12.245);

B. Minor Permit Revision (PCC 17.12.255);

C. Significant Permit Revision (PCC 17.12.260).

The applicability and requirements for such action are defined in the above referenced regulations.

XVI. FACILITY CHANGES ALLOWED WITHOUT PERMIT REVISIONS [PCC 17.12.230]

A A facility with a Class I permit may make changes without a permit revision if all of the following apply:

1. The changes are not modifications under any provision of Title I of the ACT (Air Pollution Prevention and Control) or under A.R.S. 49-401.01(17);

2. The changes do not exceed the emissions allowable under the permit whether expressed therein as a rate of emissions or in terms of total emissions;

3. The changes do not violate any applicable requirements or trigger any additional applicable requirements;

4. The changes satisfy all requirements for a minor permit revision under PCC 17.12.255; and

5. The changes do not contravene federally enforceable permit terms and conditions that are monitoring (including test methods), record keeping, reporting, or compliance certification requirements.

B. The substitution of an item of process or pollution control equipment for an identical or substantially similar item of process or pollution control equipment shall qualify as a change that does not require a permit revision, if the substitution meets all of the requirements of XVI.A, D and E of Part A.

C. Except for sources with authority to operate under general permits, permitted sources may trade increases and decreases in emissions within the permitted facility, as established in the permit under 17.12.180.A.12 if an applicable implementation plan provides for the emissions trades, without applying for a permit revision and based on the seven working days notice prescribed in XVI.D of Part A. This provision is available if the permit does not provide for the emissions trading as a minor permit revision.

D. For each change under XVI.A through C of this Part, a written notice, by certified mail or hand delivery, shall be received by the Control Officer and the Administrator a minimum of seven (7) working days in advance of the change. Notifications of changes associated with emergency conditions, such as malfunctions necessitating the replacement of equipment, may be provided less than 7 working days in advance of the change but must be provided as far in advance of the change, or if advance notification is not practicable as soon after the change as possible.

E. Each notification shall include:

1. When the proposed change will occur;

2. A description of the change;

3. Any change in emissions of regulated air pollutants;

4. The pollutants emitted subject to the emissions trade, if any;

5. The provisions in the implementation plan that provide for the emissions trade with which the source will comply and any other information as may be required by the provisions in the implementation plan authorizing the trade;

6. If the emissions trading provisions of the implementation plan are invoked, then the permit requirements with which the source will comply; and

7. Any permit term or condition that is no longer applicable as a result of the change.

F. The permit shield described in PCC 17.12.310 shall not apply to any change made under XVI.A through C of Part A. Compliance with the permit requirements that the source will meet using the emissions trade shall be determined according to requirements of the implementation plan authorizing the emissions trade.

G. Except as otherwise provided for in the permit, making a change from one alternative operating scenario to another as proved under PCC 17.12.180.A.11 shall not require any prior notice under XVI of Part A.

H. Notwithstanding any other part of this Section, the Control Officer may require a permit to be revised for any change that when considered together with any other changes submitted by the same source under this section over the term of the permit, do not satisfy XVI.A of this Part.

XVII. TESTING REQUIREMENTS [PCC 17.12.050]

A. Operational Conditions During Testing

Performance Tests shall be conducted while the unit is operating at full load under representative operational conditions unless other conditions are required by the applicable test method or in this permit. With prior written approval from the Control Officer, testing may be performed at a lower rate. Operations during start-up, shutdown, and malfunction (as defined in PCC 17.04.340.A.) shall not constitute representative operational conditions unless otherwise specified in the applicable requirement.

B. Tests shall be conducted and data reduced in accordance with the test methods and procedures contained in the Arizona Testing Manual, 40 CFR 52; Appendices D and E, 40 CFR 60; Appendices A through F; and 40 CFR 61, Appendices B and C unless modified by the Control Officer pursuant to PCC 17.12.050.B or by the Director pursuant to A.A.C. R18-2-312.B.

C. Test Plan

At least 14 calendar days prior to performing a test, the Permittee shall submit a test plan to the Control Officer, in accordance with PCC 17.12.050.B. and the Arizona Testing Manual.

D. Stack Sampling Facilities

The Permittee shall provide or cause to be provided, performance testing facilities as follows:

1. Sampling ports adequate for test methods applicable to the facility;

2. Safe sampling platforms;

3. Safe access to sampling platforms; and

4. Utilities for sampling and testing equipment.

E. Interpretation of Final Results

Each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For the purpose of determining compliance with an applicable standard, the arithmetic means of results of the three runs shall apply. In the event that a sample is accidentally lost or conditions occur in which one of the three runs is required to be discontinued because of forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the Permittee's control, compliance may, upon the Control Officer's approval, be determined using the arithmetic mean of the results of the other two runs. If the Control Officer or the Control Officer's designee is present, tests may only be stopped with the Control Officer's or such designee's approval. If the Control Officer or the Control Officer's designee is not present, tests may only be stopped for good cause. Good cause includes: forced shutdown, failure of an irreplaceable portion of the sample train, extreme meteorological conditions, or other circumstances beyond the Permittee's control. Termination of any test without good cause after the first run is commenced shall constitute a failure of the test. Supporting documentation, which demonstrates good cause, must be submitted.

F. Report of Final Test Results

A written report of the results of all performance tests shall be submitted to the Control Officer within 45 days after the test is performed. The report shall be submitted in accordance with the Arizona Testing Manual.

XVIII. PROPERTY RIGHTS [PCC 17.12.180.A.8.d]

This permit does not convey any property rights of any sort, or any exclusive privilege.

XIX. SEVERABILITY CLAUSE [PCC 17.12.180.A.7]

The provisions of this permit are severable. If any provision of this permit is held invalid, the remainder of this permit shall not be affected thereby.

XX. ACCIDENT PREVENTION REQUIREMENTS UNDER THE CLEAN AIR ACT (CAA Section 112(r))

Should this stationary source, as defined in 40 CFR Part 68.3, become subject to the accidental release prevention regulations in Part 68, then the Permittee shall submit a risk management plan (RMP) by the date specified in Section 68.10 and shall certify compliance with the requirements of Part 68 as part of the semiannual compliance certification as required by 40 CFR Part 70 and Part B of this permit.

XXI. ASBESTOS REQUIREMENTS (Demolition/ Renovation)

Should this stationary source, pursuant to 40 CFR 61, Subpart M become subject to the National Emission Standards for Hazardous Air Pollutants - Asbestos for asbestos regulations when conducting any renovation or demolition at this premises, then the Permittee shall submit proper notification as described in 40 CFR Subpart M and shall comply with all other applicable requirements of subpart M. The Permittee shall keep a record of all relevant paperwork on file. [40 CFR 61, Subpart M]

XXII. STRATOSPHERIC OZONE DEPLETING SUBSTANCES

The Permittee shall not use, sell, or offer for sale any fluid as a substitute material for use in any motor vehicle, residential, commercial, or industrial air conditioning system, refrigerator or freezer unit, or other cooling or heating device designed to use a chlorofluorocarbon (CFC) or hydrochlorofluorocarbon (HCFC) compound as a working fluid, unless such fluid has been approved for sale and such use by the Administrator. The Permittee shall keep a record of all paperwork relevant to the applicable requirements of 40 CFR 82, Subpart F onsite. [40 CFR 82 & PCC 17.16.710]

PART B: SPECIFIC CONDITIONS
All standards are Federally Enforceable unless otherwise noted
[References are to Title 17 of the Pima County Code unless otherwise noted]

I. APPLICABILITY

Equipment covered by this permit constitutes a ***Major Source*** based on 8760 hours of operation per year and considering emissions from other emission units of the same SIC Code at this facility. Equipment specifically addressed by the permit is listed in Attachment D, "Equipment List" and falls under the following Categories:

A. Fossil Fuel Fired Steam Generators

B. Stationary Rotating Machinery (including Stationary Turbines IGT1, IGT2 & future AOS for IGT3)

C. Auxiliary Boiler

D. Cooling Towers

E. Coal Preparation Plant

F Fly-Ash Handling Systems

G. Open Areas, Roadways, & Streets

H All Operations

Affected Emission Source Classification: **Class I; Major Stationary Source (SOx, NOx, CO, VOC, PM_{10} & HAPs).**

II. EMISSION LIMITS & STANDARDS [PCC 17.12.180.A.2]

A. Fossil Fuel Fired Steam Generators

1. Particulate Matter Standard [PCC 17.16.160.C.1]
[Locally Enforceable Condition]

The Permittee shall not cause, allow, or permit the emission of particulate matter from any fossil fuel-fired steam generator in excess of the amounts calculated by the following equation:

$E = 1.02Q^{0.769}$ where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.
Q = the heat input in million Btu per hour.

2. Sulfur Dioxide Standard [PCC 17.16.160.D.1]
[Locally Enforceable Condition]

a. UNITS I1, I2, & I3

The Permittee shall not cause, allow, or permit the emission of more than 1.0 pound of sulfur dioxide as a three hour average per million Btu heat input when firing liquid fuel.

b. UNIT I4

The Permittee shall not cause, allow, or permit the emission of more than 1.0 pound of sulfur dioxide as a three-hour average, per million Btu heat input.

[Installation Permit #1156, Condition 5]

3. Nitrogen Oxides Standard - UNIT I4

The Permittee shall not cause, allow, or permit the emission of more than 0.7 pounds of nitrogen oxides as a three hour average (calculated as nitrogen dioxide) per million BTU heat input. [Installation Permit #1156, Condition 5]

4. Opacity Standard - UNIT I4

The Permittee shall not cause, allow, or permit to be emitted into the atmosphere any plume or effluent from the boiler which exceeds 20 percent opacity, as measured in accordance with EPA Reference Method 9. [Installation Permit #1156, Condition 5]

5. Fuel Limitations

a. The Permittee shall not use high sulfur oil (fuel sulfur content > 0.90% by weight) as a fuel unless the Permittee demonstrates to the satisfaction of the Control Officer that sufficient quantities of low sulfur oil are not available for use by the source and that it has adequate facilities and contingency plans to insure that the sulfur dioxide ambient air quality standards set forth in 17.08.020 will not be violated. [PCC 17.16.160.G]

[Locally Enforceable Condition]

b. UNITS I1, I2, & I3

The Permittee shall only burn the following as fuel: [PCC 17.12.190]

i. Natural gas;

ii. Fuel Oils #2 through #6 or equivalent;

iii. Co-firing Natural gas with Fuel Oils #2 through #6 or equivalent;

iv. Co-firing any of the fuels listed above (II.A.5.b.i through ii of this Part) with Landfill Gas.

c. UNIT I4

i. The Permittee shall only burn the following as fuel: [PCC 17.12.190]

(A) Coal;

(B) Natural Gas;

(C) Fuel Oil #2 through #6;

(D) Co-Firing Natural Gas with coal or fuel oils #2 through #6;

(E) Co-firing Landfill Gas with fuels listed above (II.A.5.c.i.(A) through (C) of this Part).

(F) Except for short-term fuel switching (three hours or less), fuels shall not be fired simultaneously unless the continuous monitoring systems are operating.
[Installation Permit #1156, Condition 12]

ii. The maximum sulfur content of coal shall be less than or equal to 0.50 percent by weight at 10,000 BTU/lb on a three hour average basis.
[Installation Permit #1156, Condition 4]

B. Stationary Rotating Machinery (including Stationary Turbines IGT1 and IGT2)

1. Particulate Matter Standard [PCC 17.16.340.C]

The Permittee shall not cause, allow, or permit the emission of particulate matter, caused by combustion of fuel, from any of the stacks of stationary rotating machinery in excess of the amounts calculated by the following equation:

$E = 1.02Q^{0.769}$ where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.
Q = the heat input in million Btu per hour.

2. Sulfur Dioxide Standard

The Permittee shall not emit more than 1.0 pounds of sulfur per million Btu heat input when firing low sulfur oil. [PCC 17.16.340.F]

3. Opacity Standard

a. The Permittee shall not cause, allow or permit to be emitted into the atmosphere from any stationary rotating machinery, smoke for any period of time greater than ten consecutive seconds which exceeds 40 percent opacity. Visible emissions when starting cold equipment shall be exempt from this requirement (40 percent opacity) for the first ten minutes. [PCC 17.16.340.E]
[Locally Enforceable Condition]

b. The Permittee shall not cause or permit the effluent from a single emission point, multiple emissions point, or fugitive emissions source to have an average optical density equal to or greater than opacity limiting standards specified in Table 321 of the Pima County Standard Implementation Plan (SIP): subject to the following provisions:
[SIP Rule 321]

i. Opacities (optical densities) of an effluent shall be measured by a certified visible emissions evaluator with his natural eyes, approximately following the procedures which were used during his certification, or by an approved and precisely calibrated in-stack monitoring instrument.

ii. A violation of an opacity standard shall be determined by measuring and recording a set of consecutive, instantaneous opacities, and calculating the arithmetic average of the measurements within the set unless otherwise noted herein. The measurements shall be made at approximately fifteen-second intervals for a period of at least six minutes, and the number of required measurements shall be as specified in Table 321. Sets need not be consecutive in time, and in no case shall two sets overlap. If the average opacity of the set of instantaneous measurements exceeds the maximum allowed by any rule, this shall constitute a violation.

iii. The use of air or other gaseous diluents solely for the purpose of achieving compliance with an opacity standard on prohibited.

iv. When the presence of uncombined water is the only reason for failure of a source to otherwise meet the requirements of II.B.3.b of Part B, II.B.3.b shall not apply.

4. Fuel Limitations

a. The Permittee shall not use high sulfur oil (fuel sulfur content > 0.90% by weight) as a fuel unless the Permittee demonstrates to the satisfaction of the Control Officer that sufficient quantities of low sulfur oil are not available for use by the source and that it has adequate facilities and contingency plans to insure that the sulfur dioxide ambient air quality standards set forth in 17.08.020 will not be violated. [PCC 17.16.340.H]

[Locally Enforceable Condition]

b. The Permittee shall only burn the following as fuel in UNITS IGT1 and IGT2: [PCC 17.12.190]

i. Natural gas;

ii. Fuel oil: #2 Distillate; or

iii. Co-firing natural gas with Fuel oil #2 Distillate.

c. The Permittee shall only burn diesel as fuel in UNITS IGT1A and IGT2A (stationary turbine starter engines). [PCC 17.12.190]

C. Auxiliary Boiler

1. Particulate Matter Standard [PCC 17.16.165.C]

[Locally Enforceable Condition]

The Permittee shall not cause, allow or permit the emission of particulate matter, caused by the combustion of fuel from the stack of

$E = 1.02Q^{0.769}$ where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.
Q = the heat input in million Btu per hour.

2. Sulfur Dioxide Standard [PCC 17.16.165.E]

[Locally Enforceable Condition]

The Permittee shall not cause, allow, or permit the emission of more than 1.0 pounds of sulfur dioxide per million Btu heat input when firing liquid fuel.

3. Fuel Limitations

a. The Permittee shall not use high sulfur oil (fuel sulfur content > 0.90% by weight) as a fuel unless the Permittee demonstrates to the satisfaction of the Control Officer that sufficient quantities of low sulfur oil are not available for use by the source and that it has adequate facilities and contingency plans to insure that the sulfur dioxide ambient air quality standards set forth in 17.08.020 will not be violated. [PCC 17.16.165.G]

[Locally Enforceable Condition]

b. Permittee shall only burn the following as fuel in the auxiliary boiler: [PCC 17.12.190]

i. Natural gas;

ii. Fuel oil #2 Distillate; or

iii. Co-firing Natural gas with Fuel oil #2 Distillate.

D. Cooling Towers

1. Particulate Matter Standard [PCC 17.16.430.A.1.b]

[Locally Enforceable Condition]

The Permittee shall not cause or allow particulate emissions from the cooling towers to exceed:

$E = 17.31P^{0.16}$ where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.
P = the process rate in tons-mass per hour.

2. Odor Limiting Standard

The Permittee shall not emit gaseous or odorous materials from equipment, operations, or premises in such quantities or concentrations to cause air pollution. [PCC 17.16.430.D]

[Locally Enforceable Condition]

3. Where a stack, vent, or other outlet is at such a level that fumes, gas mist, odor, smoke, vapor or any combination thereof constituting air pollution is discharged to adjoining property, the Control Officer may require the installation of abatement equipment or the alteration of such stack, vent, or other outlet by the Permittee thereof to a degree that will adequately dilute, reduce, or eliminate the discharge of air pollution to adjoining property. [PCC 17.16.430.G]

[Locally Enforceable Condition]

4. The Permittee shall not used chromium-based water treatment chemicals in the cooling towers. [PCC 17.12.190]**[Material Permit Condition]**

E. Coal Preparation Plant (CPP) **[Locally Enforceable Conditions]**

1. Particulate Matter Standards [PCC 17.16.310.B]

   The Permittee shall not cause, allow or permit the discharge of particulate matter into the atmosphere in any one hour from any existing coal preparation plant in total quantities in excess of the amounts calculated by one of the following equations set forth:

   a. For process sources having a process weight rate of 60,000 pounds per hour (30 tons per hour) or less, the maximum allowable emissions shall be determined by the following equation:

      $E = 3.59P^{0.62}$ where:

      E = the maximum allowable particulate emissions rate in pounds-mass per hour.
      P = the process weight in tons-mass per hour.

   b. For process sources having a process weight rate greater than 60,000 pounds per hour (30 tons per hour), the maximum allowable emissions shall be determined by the following equation:

      $E = 17.31P^{0.16}$ where:

      "E" and "P" are defined as indicated in II.E.1.a. of Part B.

   c. The total process weight from all similar units employing a similar type process shall be used in determining the maximum allowable emission of particulate matter. [PCC 17.16.310.D]

2. The Permittee shall not cause, suffer, allow, or permit crushing, screening, handling, transporting, or conveying of materials or other operations likely to result in significant amounts of airborne dust without taking reasonable precautions, such as the use of spray bars, wetting agents, dust suppressants, covering the load, and hoods to prevent excessive amounts of particulate matter from becoming airborne. [PCC 17.16.100.A & PCC 17.16.310.E]

3. The Permittee shall not cause, suffer, allow, or permit organic or inorganic dust producing material to be stacked, piled or otherwise stored without taking reasonable precautions such as chemical stabilization, wetting, or covering to prevent excessive amounts of particulate matter from becoming airborne. [PCC 17.16.110.A & PCC 17.16.310.E]

4. Stacking and reclaiming machinery utilized at storage piles shall be operated at all times with a minimum fall of material and in such manner, or with the use of spray bars and wetting agents, as to minimize and control to ensure compliance with PCC 17.16.050. [PCC 17.16.110.B & PCC 17.16.310.E]

5. The Permittee shall employ one or more of the following reasonable precautions to prevent excessive amounts of particulate matter from becoming airborne:

   a. Use spray bars, hoods, wetting agents, dust suppressants, or cover when crushing, handling, or conveying material that is likely to give rise to airborne dust; [PCC 17.16.100]

b. Adequately cover, or use wetting agents, chemical stabilization, or dust suppressants when stacking, piling, or otherwise storing organic or inorganic dust producing material; [PCC 17.16.110.A]

c. Operate stacking and reclaiming machinery utilized at storage piles at all times with a minimum fall of material and with the use of spray bars and wetting agents; [PCC 17.16.110.B]

d. The emergency coal storage pile is exempt from the requirements listed above (Part B.II.E.5.a through c of this Part).

F. Fly-Ash Handling Systems (FAHS) **[Locally Enforceable Conditions]**

1. Particulate Matter Standards [PCC 17.16.430.A.1]

The Permittee shall not cause or permit the discharge of particulate matter into the atmosphere in any one hour from FAHS in total quantities in excess of the amounts calculated by one of the following equations set forth:

a. For process sources having a process weight rate of 60,000 pounds per hour (30 tons per hour) or less, the maximum allowable emissions shall be determined by the following equation:

$E = 3.59P^{0.62}$ where:

E = the maximum allowable particulate emissions rate in pounds-mass per hour.
P = the process weight in tons-mass per hour.

b. For process weight rates greater than 60,000 pounds per hour (30 tons per hour), the maximum allowable emissions shall be determined by the following equation:

$E = 17.31P^{0.16}$ where:

"E" and "P" are defined as indicated in II.F.1.a of Part B.

c. The total process weight from all similar units employing a similar type process shall be used in determining the maximum allowable emission of particulate matter. [PCC 17.16.430.B]

2. The Permittee shall not cause, suffer, allow, or permit crushing, screening, handling, transporting, or conveying of materials or other operations likely to result in significant amounts of airborne dust without taking reasonable precautions, such as the use of spray bars, wetting agents, dust suppressants, covering the load, and hoods to prevent excessive amounts of particulate matter from becoming airborne. [PCC 17.16.100.A & PCC 17.16.310.E]

3. The Permittee shall not cause, suffer, allow, or permit organic or inorganic dust producing material to be stacked, piled or otherwise stored without taking reasonable precautions such as chemical stabilization, wetting, or covering to prevent excessive amounts of particulate matter from becoming airborne. [PCC 17.16.110.A & PCC 17.16.310.E]

4. Stacking and reclaiming machinery utilized at storage piles shall be operated at all times with a minimum fall of material and in such manner, or with the use of spray bars and wetting agents, as to minimize and control to ensure compliance with PCC 17.16.050.
[PCC 17.16.110.B & PCC 17.16.310.E]

5. The Permittee shall employ one or more of the following reasonable precautions to prevent excessive amounts of particulate matter from becoming airborne:

   a. Use spray bars, hoods, wetting agents, dust suppressants, or cover when crushing, handling, or conveying material that is likely to give rise to airborne dust; [PCC 17.16.100]

   b. Adequately cover, or use wetting agents, chemical stabilization, or dust suppressants when stacking, piling, or otherwise storing organic or inorganic dust producing material; [PCC 17.16.110.A]

   c. Operate stacking and reclaiming machinery utilized at storage piles at all times with a minimum fall of material and with the use of spray bars and wetting agents;

G. Open Areas, Roadways, & Streets

1. The Permittee shall not cause, suffer, allow, or permit a building or its appurtenances, or a building site, or a driveway, or a parking area, or a vacant lot or other open area to be constructed, used, altered, repaired, demolished, cleared, or leveled, or the earth to be moved or excavated, without taking reasonable precautions to limit excessive amounts of particulate matter from becoming airborne. Dust and other types of air contaminants shall be kept to a minimum by good modern practices such as using an approved dust suppressant or adhesive soil stabilizer, paving, covering, landscaping, continuous wetting, detouring, barring access, or other acceptable means. [PCC 17.16.080.A & SIP 318.A]

2. The Permittee shall not leave any vacant lot, building site, parking area, or other open area in such a state after construction, alteration, clearing, leveling, or excavation that naturally induced wind blowing over the area causes a violation the opacity standards in II.H.1 of this Part. Dust and other types of air contaminants shall be kept to a minimum by good modern practices such as landscaping, covering with gravel or vegetation, paving, or applying equivalently effective controls. [PCC 17.16.080.B & SIP 318.B]

3. No vacant lot, parking area, sales lot, or other open urban area shall be used by motor vehicles in such a manner that visible dust emissions induced by vehicular traffic on the area cause a violation of the opacity standards in II.H.1 of Part B. [PCC 17.16.080.C & SIP 318.C]

4. The Permittee shall not cause, suffer, allow or permit the use, repair, construction or reconstruction of a roadway or alley without taking reasonable precautions to prevent excessive amounts of particulate matter from becoming airborne. Dust and other particulates shall be kept to a minimum by employing temporary paving, dust suppressants, wetting down, detouring or by other reasonable means. [PCC 17.16.090.A]

5. The surfacing of roadways with asbestos tailings is prohibited. [PCC 17.16.090.F & SIP 315]

H. All Operations

1. Opacity Standards

a. Opacity emissions from non-point sources shall not exceed 20 percent as measured in accordance with the Arizona Testing manual, and EPA Reference Method 9.
[PCC 17.16.050.B]**[Locally Enforceable Condition]**

b. Except as provided elsewhere in this Part B, the Permittee shall not cause, allow, or permit to be emitted into the atmosphere any plume or effluent the opacity of which exceeds 20 percent, as measured in accordance with EPA Reference Method 9 in 40 CFR, Appendix A. [PCC 17.16.130.B.3]**[Locally Enforceable Condition]**

2. Definition of Heat Input

For the purposes of this section (II.A through II. C of this Part) the heat input shall be the aggregate heat content of all fuels whose products of combustion pass through a stack or other outlet. The heat content of solid fuel shall be determined in accordance with PCC 17.12.045.C.
[PCC 17.16.160.B, 17.16.165.B & PCC 17.16.340.B] **[Locally Enforceable Condition]**

3. Odor Limiting Standard

The Permittee shall not emit gaseous or odorous materials from equipment, operations or premises under his control in such quantities or concentrations as to cause air pollution.
[PCC 17.16.030] **[Locally Enforceable Condition]**

4. Visible Emissions

The Permittee shall not cause or permit the airborne diffusion of visible emissions, including fugitive dust, beyond the property boundary line within which the emissions become airborne. In actual practice, the airborne diffusion of visible emissions across property lines shall be prevented by appropriately controlling the emissions at the point of discharge, or ceasing entirely the activity or operation which is causing or contributing to the emissions. This condition shall not apply when wind speeds exceed twenty-five miles per hour (as estimated by an enforcement officer using the Beaufort Scale of Wind-Speed Equivalents, or as recorded by the National Weather Service). This exception does not apply if control measures have not been taken or were not commensurate with the size or scope of the emission source.
[PCC 17.16.050.D & SIP 343]

III. AIR POLLUTION CONTROLS

A. Fossil Fuel Fired Steam Generators – UNIT I4

The Permittee shall install, maintain, and operate a baghouse on UNIT I4 to capture particulate emissions resulting from combustion of coal fuel. The baghouse shall be operated at all times when UNIT I4 is firing coal (exclusively or in combination) and when transitioning to or from firing coal fuel (exclusively or in combination). Air pollution control equipment shall be operated in a manner consistent with good modern practices for minimizing emissions. [Installation Permit #1156, Condition 8]
[Material Permit Condition]

B. Coal Preparation Plant

1. Spray bars shall be used in conjunction with other air pollution control equipment in the coal handling/storage systems to prevent fugitive dust. [Installation Permit #1156, Condition 7]

2. At all times when the equipment in the Table 1 is in operation, the Permittee shall maintain and operate the associated air pollution control equipment in accordance with good modern practices for minimizing emissions: [PCC 17.12.180.A.3]**[Material Permit Condition]**

Table 1

Equipment Description	Pollution Control Equipment
Rotary Car Dumper	Enclosure, Spray Bars & Dust Collector
Live Coal Storage Facility	Enclosure & Dust Collector
Crusher Facility	Enclosure & Dust Collector
Tower 4	Enclosure & Dust Collector
As Received Sampler	Enclosure
Emergency Storage Pile	Telescopic Chute
Conveyors C2, C4, C5, C6, C7A, C7B	Weather Covers

C. Fly-Ash Handling Systems

1. Spray bars shall be used in conjunction with other air pollution control equipment in the flyash handling/storage systems to prevent fugitive dust. [Installation Permit #1156, Condition 7]

2. At all times when the equipment in the following table is in operation, the Permittee shall maintain and operate the associated air pollution control equipment in accordance with good modern practices for minimizing emissions: **[Material Permit Condition]**

Table B

Equipment Description	Pollution Control Equipment
Flyash Silo A	Dust Collector
Flyash Silo A Vent	Dust Collector
Flyash Silo B	Dust Collector
Flyash Silo B Vent	Dust Collector
Flyash Storage Tank #4	Dust Collector

3. The loading sleeve on the flyash hopper shall incorporate a cut-off valve. Flyash shall be wetted prior to any handling in an open area. The fly ash handling area and haul road shall be paved. [Installation Permit #1156, Condition 10]**[Material Permit Condition]**

4. The flyash shall be loaded into enclosed hopper trucks through a closed gravity feed system and the outer sleeve of the dual sleeve system shall seal with the loading port of the truck and it shall be vented back to the hopper baghouse. [Installation Permit #1156, Condition 11] **[Material Permit Condition]**

D. Additional Pollution Control Equipment

1. The Control Officer reserves the right to require any additional air pollution control equipment as deemed necessary for UNIT I4, the Coal Preparation Plant and Fly-Ash Handling Systems. [Installation Permit #1156, Condition 13]

2. The requirement for any additional air pollution control equipment shall be requested by the Control Officer through a permit reopening pursuant to III of Part A. [PCC 17.12.180.A.15]

IV. MONITORING REQUIREMENTS [PCC 17.12.180.A.3]

A. Fossil Fuel Fired Steam Generators

1. Visible Emissions

a. UNITS I1, I2, & I3

i. If liquid fuel is combusted in the unit continuously for a time period greater than 48 hours but less than 168 hours, (equal to one week), at least one opacity reading will be observed at the exit of the unit's stack.

ii. When continuously firing liquid fuel for a time period greater than 168 hours, the Permittee shall conduct at least one opacity reading during each 168-hour period at the exit of the unit's stack by an employee certified in Method 9.

iii. All opacity readings shall be observed in accordance with EPA Reference Method 9. The Permittee shall log in ink or in an unchangeable electronic format and maintain a record of the opacity readings from above and the number of hours fuel oil is burned continuously.

b. UNIT I4

i. The Permittee shall install, maintain, calibrate, and operate a continuous opacity monitoring system (COMS). When the Permittee is changing fuel to natural gas, the COMS shall be operated during the transition period, and deactivated only after the opacity readings have stabilized to levels associated with normal natural gas combustion. [Installation Permit #1156, Condition #6] **[Material Permit Condition]**

ii. The COMS shall meet the following requirements:

(A) 40 CFR 60, Appendix B, Performance Specification 1, Specification and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources.

(1) Apparatus

(2) Installation Specifications

(3) Design and Performance Specifications

(4) Design Specifications Verification Procedure

(5) Performance Specifications Verification Procedure

(6) Equations

(B) Calibration Checks

The Permittee shall record the zero and span drift in accordance with the method prescribed by the manufacturer's recommended zero and span check at least once daily unless the manufacturer has recommended adjustments at shorter intervals, in which case such recommendations shall be followed.
[PCC 17.12.060.D.6]

(1) Zero and Span Drift Adjustments [PCC 17.12.060.D]
[40 CFR 60 Appendix B Spec 1, 13.3 (6)]

(a) Permittee shall adjust the zero or span whenever the 24-hour zero drift or 24-hour calibration drift limits of 2% opacity are exceeded.

(b) The system shall allow for the amount of excess zero and span drift measured at the 24-hour interval checks to be recorded and quantified.

(c) The optical surfaces exposed to the effluent gases shall be cleaned prior to performing the zero and span drift adjustments except that for systems using automatic zero adjustments.

(d) The optical surfaces shall be cleaned when the cumulative automatic zero compensation exceeds 4% opacity.

(2) System Checks

Each analyzer shall include a calibration system for simulating a zero opacity (or no greater than 10%) condition and an upscale opacity condition for the purposes of performing periodic checks of the transmissometer calibration while on an operating stack or duct. This calibration will provide, as a minimum, a system check of the analyzer internal optics and all electronic circuitry including the lamp and photodetector assembly.

(3) Minimum Frequency of Operation

Except during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments, the COMS shall be in continuous operation and shall complete a minimum of one cycle of sampling and analyzing for each successive 15-second period and one cycle of data recording for each successive 6-minute period.
[PCC 17.12.060.E.2]

(4) Data Reduction and Missing Data

(a) Permittee shall reduce all data from the COMS to 6-minute averages. Six-minute opacity averages shall be calculated from 24 or more data points equally spaced over each 6-minute period.

(b) Data recorded during periods of system breakdowns, repairs, calibration checks, and zero and span adjustments shall not be included in the data averages computed under the previous paragraph. An arithmetic or integrated average of all data may be used.

2. Particulate Matter – Compliance Assurance Monitoring for UNIT I4 (CAM)

a. Indicator, Measurement Approach and Data Representativeness

i. Visible Emissions Opacity

When firing coal and/or liquid fuel the Permittee shall maintain and continuously operate a Continuous Opacity Monitoring Systems (COMS) to measure visible emissions on the stack (Opacity) which is indicative of operation of the UNIT I4 fabric filter in a manner necessary to comply with particulate matter emission standards. [40 CFR 64.6(c)(1) & Installation Permit #1156, Condition #6]

[Material Permit Condition]

ii. Baghouse Condition

The Permittee shall conduct: [40 CFR 64.6(c)(1)]

[Material Permit Condition]

(A) Sampling and analysis of representative bag samples once per year before the anniversary date of the issuance of the permit. The analyses of representative bag samples will be used as a factor in determining when bag replacement is to be scheduled.

(B) An inspection and maintenance program, to be performed during a scheduled major outage that includes an internal visual inspection of the entire baghouse including bag compartments for signs of bag failure. Any known/ discovered broken bags will be either replaced or capped off until ready to be replaced. Compartments identified during the inspection with one or more broken bags, that have not been capped off or replaced, will be isolated and only placed back into service when the broken bags have been replaced.

b. Indicator range

i. Visible Emissions Opacity

(A) An average opacity measurement of 10 percent or greater in any 3-hour rolling average period, except during startup, shutdown and malfunction shall constitute an excursion. [40 CFR 64.3(a)(2)]

(B) Each three-hour rolling average opacity, except during startup, shutdown and malfunction during which a fabric filter parameter alarm is activated shall also constitute an excursion for the purposes of responding to and reporting excursions under 40 CFR 64.7. [40 CFR 64.6(c)(2)]

ii. Baghouse Condition

Failure to sample and analyze the bags' conditions as described in IV.A.2.a.ii.(a) of Part B shall constitute an excursion.

c. Quality Assurance/ Quality Control (QA/QC) Practices [40 CFR 64.6(c)(1)]

i. Visible Emissions Opacity

The Permittee shall meet the QA/ QC requirements of 40 CFR Part 60, Appendix B, Performance Specification 1, "Specification and Test Procedures for Opacity Continuous Emission Monitoring Systems in Stationary Sources."

ii. Baghouse Condition

The Permittee shall ensure that experienced personnel perform conduct the inspection and maintenance program.

d. Data Collection Procedure & Monitoring Frequency

i. Visible Emissions Opacity

(A) The Permittee shall conduct all monitoring in continuous operation with data recorded as 6-minute averages (or shall collect data at all required intervals) at all times that the pollutant specific emission unit is operating. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments). Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. [40 CFR 64.7(c)]

(B) Averaging Period

The Permittee shall have a three-hour rolling average period of visible emissions. The three-hour average opacity block parameter shall be equipped with an alarm. [40 CFR 64.6(c)(1)]

ii. Baghouse Condition

The monitoring frequency of the baghouse may vary. In addition the Permittee shall:

(A) Keep the results of the annual representative bag analyses on site.

(B) Record the results of all inspection and maintenance activities and keep them on site.

e. Prior to making any changes to the alarm set point or alarm delay time described in IV.A.2.d.i.(B) of Part B, the Permittee shall submit written notification to the Control Officer. Such notification shall include the proposed new alarm set point or alarm delay time and the reason for the proposed change. The proposed change may be made without the prior approval of the Control Officer. [40 CFR 64.6(c)(2)]

f. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or any necessary follow-up actions to return operation to within the indicator range, designated condition, or below the applicable emission limitation or standard, as applicable. [40 CFR 64.7(d)(1)]

g. Determination of whether the owner or operator has used acceptable procedures in response to an excursion or exceedance will be based on information available, which may include but is not limited to, monitoring results, review of operation and maintenance procedures and records, and inspection of the control device, associated capture system, and the process. [40 CFR 64.7(d)(2)]

h. In addition to the general reporting requirements of this permit, all reports of excursions shall follow the format outlined in 40 CFR 64.9(a)(2) and submitted with the report required in VI.F of Part B. For the purposes of defining “prompt” for excursions, reporting of excursions in this report shall be considered prompt reporting. [40 CFR 64.9(a)]

i. In addition to the general recordkeeping requirements of this permit, all CAM recordkeeping shall follow the format outlined in 40 CFR 64.9(b). [40 CFR 64.9(b)]

3. Sulfur Dioxide and Nitrogen Oxides – UNIT I4

a. The Permittee shall maintain, calibrate, and operate a continuous emissions monitoring system (CEMS) for measuring the sulfur dioxide emissions, nitrogen oxides emissions, and diluents. When exclusively firing natural gas, the Permittee may use the emission factor of 0.0006 lb/MMBTU to estimate emissions of SO_2 in place of the continuous SO_2 emission monitor. [Installation Permit #1156, Condition #6]

[Material Permit Condition]

b. The CEMS for SO_2, NOx and diluents shall meet the following requirements:

i. 40 CFR Part 75, Appendix A, “Specification and Test Procedures”

(A) Installation and measurement location

(B) Equipment specifications

(C) Performance specifications

(D) Data Acquisition and handling systems

(E) Calibration gas

(F) Certifications tests and procedures

(G) Calculations

ii. 40 CFR Part 75, Appendix B, "Quality Assurance and Quality Control Procedures"

(A) Quality Assurance/ Quality Control program
(B) Frequency of testing

c. Permittee shall comply with all the recordkeeping and reporting requirements of 40 CFR Part 75 Subparts F and G respectively.

4. Fuel Limitations - UNIT I4

Coal consumed shall be sampled for moisture, ash, sulfur content, and gross calorific value. A coal analysis shall be performed on each train load and the results of these analyses shall be retained for at least five years following the date of measurement. All sample collection, sample preparation, and analyses performed or caused to be performed shall be conducted according to the most recent ASTM methods. [Installation Permit 1156, Condition #3]

B. Stationary Rotating Machinery (including Stationary Turbines IGT1 & IGT2)

1. Visible Emissions

a. If liquid fuel is burned in a unit continuously for a time period greater than 48 hours but less than 168 hours, at least one six minute opacity reading will be observed at the exit of the unit's stack.

b. If liquid fuel is burned in a unit continuously for a time period greater than 168 hours, at least one six-minute opacity reading will be observed during each 168-hour period, at the exit of the unit's stack.

c. All opacity readings will be observed in accordance with EPA Reference Method 9. The Permittee shall log in ink or in an unchangeable electronic format and maintain a record of the opacity readings from above and the number of hours fuel oil is continuously burned.

2. Sulfur Dioxide

For units firing gaseous fuels, the Permittee shall monitor daily, the sulfur content of the fuel being combusted in these machines. This requirement may be complied with by maintaining a vendor-provided copy of that part of the Federal Energy Regulatory Commission (FERC)-approved Tariff agreement that limits transmission of pipeline quality natural gas of sulfur content to less than 0.9 percent by weight. [PCC 17.16.340.I]

3. Hours of Operation

The Permittee shall keep track of the hours of operation, computed as a twelve-month rolling total, until the performance tests specified in VII.A.1 & 3 of this Part are completed.

C. Coal Preparation Plant [PCC 17.12.180.A.3]

1. A certified Method 9 observer shall conduct a weekly visual survey of visible emissions from the coal preparation plant when it is in operation. This weekly survey shall include observation of all exposed transfer points, enclosed transfer points, the coal storage pile, and the baghouses in the coal handling system. The Permittee shall record the location observed, the name of the observer, date on which the observation was made, and the results of the observation.

2. If the observer sees a plume from an emission point that appears to exceed 20% opacity on an instantaneous basis, the observer shall take a six-minute Method 9 observation of the plume if possible.

3. If the six-minute opacity of the plume exceeds 20%, the Permittee shall do the following:

   a. Adjust or repair the controls or equipment to reduce opacity to below 20%; and

   b. Report it as an excess emission in accordance with XII.A of Part A of this permit.

4. If the six-minute opacity of the plume is less than 20%, the observer shall make a record of the following:

   a. Date and time of the observation; and

   b. The results of the Method 9 observation.

D. Fly-Ash Handling System [PCC 17.12.180.A.3]

1. A certified Method 9 observer shall conduct a weekly visual survey of visible emissions from the fly-ash handling system when it is in operation. This weekly survey shall include observation of all exposed transfer points, enclosed transfer points and the baghouses in the fly-ash handling system. The Permittee shall record the location observed, the name of the observer, date on which the observation was made, and the results of the observation.

2. If the observer sees a plume from an emission point that appears to exceed 20% opacity on an instantaneous basis, the observer shall take a six-minute Method 9 observation of the plume if possible.

3. If the six-minute opacity of the plume exceeds 20%, the Permittee shall do the following:

   a. Adjust or repair the controls or equipment to reduce opacity to below 20%; and

   b. Report it as an excess emission in accordance with XII.A of Part A of this permit.

4. If the six-minute opacity of the plume is less than 20%, the observer shall make a record of the following:

   a. Date and time of the observation; and

   b. The results of the Method 9 observation.

V. RECORDKEEPING [PCC 17.12.180.A.4]

A. Fossil Fuel Fired Steam Generators

1. Particulate Matter - UNITS I1, I2, & I3

With regard to all liquid fuels, the Permittee shall keep on record, along with the fuel firing rate, the contractual agreement with the liquid fuel vendor indicating the following information concerning the liquid fuel being fired:

a. The heating value; and

b. The ash content.

2. Sulfur Dioxide - UNITS I1, I2, & I3

With regard to liquid fuel, the Permittee shall keep records of fuel supplier certifications including the following information:

a. The name of the fuel oil supplier;

b. The sulfur content of the oil from which the shipment came;

c. The heating content of the oil from which the shipment came;

d. The density of the fuel oil from which the shipment came; and

e. The method used to determine the sulfur content of the oil.

f. Engineering calculations demonstrating compliance with the standard shall be performed each time there is a change in V.A.2.b, c, or d of Part B above. These calculations shall be performed according to the following equation and maintained in a record:

$$SO_2 = \frac{2.0 \times \%S \times D_f}{HV} \times \frac{1{,}000{,}000\,Btu}{1\,MMBtu}$$ where:

SO_2 = emissions of SO_2 in lb/MMBtu
%S = Percent Sulfur by weight (decimal; i.e. 1% = 0.01)
D_f = Density of fuel in lb/gal
HV = Heating value of fuel in Btu/gal

3. Fuel Limitation

Except for fuels fired during startup and/or flame stabilization, the Permittee shall log in ink or in an electronic format a record of any change in fuel type including the following information:

a. Type of fuel change; and

b. Date and time of fuel change.

4. Hours of Operation - UNITS I1, I2, & I3

Until the performance tests specified in VII.A.1 of Part B are completed, the Permittee shall compute and record the following information in an individual log for each unit within 5 working days of the end of each month:

a. Date and time in which the unit began firing liquid fuel (exclusively or in combination); if liquid fuel combustion began in the previous month, the record shall state the fact;

b. The date and time in which the unit ceased to fire liquid fuel (exclusively or in combination); if liquid fuel combustion continues into the next month the record shall state that fact;

c. The hours of operation during which liquid fuel was fired (exclusively or in combination) in the previous month, including consecutive hours and total hours;

d. The hours of operation during which liquid fuel was fired (exclusively or in combination) in the previous 12-consecutive month period.

B. Stationary Rotating Machinery (including Stationary Turbines IGT1 & IGT2)

1. Particulate Matter

The Permittee shall keep on record, along with the fuel firing rate, the contractual agreement with the liquid fuel vendor indicating the following information concerning the liquid fuel fired in any stationary rotating machinery:

a. The heating value; and

b. The ash content.

The Permittee shall calculate the particulate matter emissions based on the above values for each applicable unit. The Permittee shall perform this calculation each time there is a change related to V.B.1.a or b of Part B in the contractual agreement. These calculations shall be maintained in a record.

2. Sulfur Dioxide

a. For units firing liquid fuels, the Permittee shall keep records of fuel supplier certifications including the following information:

i. The name of the oil supplier;

ii. The sulfur content and the heating content of the oil from which the shipment came; and

iii. The method used to determine the sulfur content of the oil.

iv. Engineering calculations demonstrating compliance with II.B.2 of Part B shall be performed each time there is a change in (ii) above (V.B.2.a.ii of Part B). These calculations shall be maintained in a record.

b. Fuel analysis shall be used to determine the sulfur content of fuel used. The Permittee may also use fuel sulfur content certifications that employ the following test methods: ASTM D 129-91 shall be used to determine the sulfur content of liquid fuels and ASTM D-1702-90, D 1072-80, D 3031-81, D 4084-82, or D 3246-81 shall be used for the sulfur content of gaseous fuels. The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Control Officer.

C. Auxiliary Boiler

Except for fuels fired during startup and/or flame stabilization, the Permittee shall log in ink or in an electronic format a record of any change in fuel type including:

1. Types of fuels changed; and

2. Date and time of fuel change.

D. Coal Preparation Plant

1. Particulate Matter

The Permittee shall maintain and operate all air pollution control equipment in accordance with best modern practices. These practices shall be on file and shall be readily available for inspection by the Control Officer.

2. The Permittee shall maintain records of emissions related maintenance performed on all air pollution control equipment.

E. Fly-Ash Handling Systems

1. Particulate Matter

The Permittee shall maintain and operate all air pollution control equipment in accordance with best modern practices. These practices shall be on file and shall be readily available for inspection by the Control Officer.

2. The Permittee shall maintain records of emissions related maintenance performed on all air pollution control equipment.

F. Open Areas, Roadways, & Streets

The Permittee shall maintain records of dates and types of control measures adopted pursuant to II.F.1, 2, & 4 of Part B.

VI. REPORTING REQUIREMENTS [PCC 17.12.180.A.5]

A. Fossil Fuel Fired Steam Generators

1. CAM Reporting – UNIT I4

For the purposes of permit deviation reporting under Condition XII of Attachment "A," the Permittee shall include the following information required by 40 CFR part 64, §64.9(a).
[40 CFR 64.7(d)]

a. Summary information on the number, duration and cause (including unknown causes, if applicable) of excursions or exceedences, as applicable, and the corrective action taken.
[40 CFR 64.9(a)(2)(i)]

b. Summary information on the number, duration and cause (including unknown causes, if applicable) for monitoring downtime incidents (other than downtime associated with zero and span or other daily calibration checks). [40 CFR 64.9(a)(2)(i)(ii)]

2. Fuel Limitation – UNIT I4

The results of the coal analyses required by IV.A.4 shall be compiled in a report to be submitted to the Control Officer within 30 days of the end of each quarter. Samples and/or analysis provided by the coal supplier may be used to satisfy this condition.
[Installation Permit #1156, Condition #3]

B. Stationary Gas Turbines (Including Stationary Turbines IGT1 & IGT2)

The Permittee shall report any daily period during which the sulfur content of fuels fired in any piece of stationary rotating machinery exceeds 0.8 percent by weight. [PCC 17.16.340.J]

C. Auxiliary Boiler - Visible Emissions

The Permittee shall report all 6-minute periods during which the visible emissions exceed 15% opacity. [PCC 17.16.165.I]

D. Special Reporting for the Affected Source or Process

The Permittee shall promptly notify and submit written reports to the Control Officer of any instances of excess emissions or deviation from permit requirements. (Refer to XI.A & B of Part A).

E. Quarterly Reports for CEMS/COMS [PCC 17.12.180.A.5]

1. Permittee shall submit a written report of all deviations to PDEQ on January 31st, April 30th, July 31st, and October 31st, covering October through December, January through March, April through June, and July through September, respectively. The reports shall include the following:

a. The magnitude of deviations computed in accordance with PCC 17.12.060, any conversion factor(s) used, and the date and time of commencement and completion of each time period of deviation.

b. Specific identification of each period of deviation that occurs during startups, shutdowns, and malfunctions of the boiler. The nature and cause of any malfunction (if known) and the corrective action taken or preventative measures adopted shall also be reported.

c. The date and time identifying each period during which the continuous monitoring system(s) were inoperative except for zero and span checks and the nature of the system repairs or adjustments. The Control Officer may require proof of continuous monitoring system performance whenever system repairs of adjustments have been made.
[PCC 17.12.060.E.4]

d. When no excess emissions have occurred or the continuous monitoring systems have not been inoperative, repaired, or adjusted, such information shall be clearly stated in the report. [PCC 17.16.060.E.5 & Installation Permit #1156, Condition # 6]

2. In addition to the requirements of the above Paragraph (VI.E.1 of this Part), the Permittee shall report all deviations in accordance with XI.B of Part A.

F. Semiannual Summary Reports of Required Monitoring [PCC 17.12.180.A.5.a]

The Permittee shall submit a semiannual summary report of all permit deviations (including excursions defined in IV.A.2 (CAM) of Part B and exceedances that have occurred during the reporting period. Semiannual reports shall be due on January 31st and July 31st of each year and shall cover the period July 1st through December 31st and January 1st through June 30th, respectively. The first semiannual report may not cover a six-month period.

G. Compliance Certification Reporting [PCC 17.12.220.A.2]

Permittee shall submit an annual compliance certification to the Control Officer pursuant to VII of Part A. Annual compliance certification reports shall be due on February 15th of each year and shall cover the period January 1st through December 31st. The first annual report may not cover a 12-month period.

H. Emissions Inventory Reporting [PCC 17.12.320]

Every source subject to a permit requirement shall complete and submit to the Control Officer, when requested, an annual emissions inventory questionnaire pursuant to 17.12.320 of the Pima County Code. (See VI of Part A of this permit).

VII. TESTING REQUIREMENTS [PCC 17.12.180.A.3.a & PCC 17.20.010]

For purposes of demonstrating compliance, these test methods shall be used, provided that for the purpose of establishing whether or not the facility has violated or is in violation of any provision of this permit, nothing in this permit shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance with applicable federal requirements if the appropriate performance or compliance procedures or methods had been performed.

The Permittee shall use the following EPA approved reference test methods to conduct performance tests for the specified pollutants when required:

A. Fossil Fuel Fired Steam Generators

1. Sulfur Dioxide – UNITS I1, I2, & I3

The Permittee shall perform an annual performance test in accordance with EPA Reference Method 6 or 6C when liquid fuel is fired greater than 1300 hours in a 12 consecutive month period.

2. UNIT I4

The Permittee shall conduct a performance test for visible emissions, particulate matter, sulfur dioxide, and nitrogen oxides each year within 90 days of the anniversary date of the permit, or a date other than the anniversary date of the permit as submitted by the Permittee and approved by the Control Officer or the Control Officer's designee. The compliance test shall be conducted while firing coal and at the maximum normal operating load of the unit or other load as approved by the Control Officer. If the unit is not burning coal during the 90 days prior to the applicable date of the compliance test, the test shall be conducted at a later date as soon as practicable after the unit commences the firing of coal, but not later than 30 days after the unit commences the firing of coal. Performance tests shall be conducted in accordance with EPA Reference Method 9 for visible emissions, EPA Reference Method 5 for particulate matter, EPA Reference Method 6 for sulfur dioxide, and EPA Reference Method 7 for nitrogen oxides.

B. Stationary Rotating Machinery (Including Stationary Turbines (IGT1 & IGT2)

1. Sulfur Dioxide

The Permittee shall perform an annual performance test in accordance with EPA Reference Method 6 or 6C when liquid fuel is fired greater than 1300 hours in a 12 consecutive month period.

2. Carbon Monoxide [A.R.S. 49-422.A.3]

The Permittee shall perform a performance test to measure the emission rate of carbon monoxide. This performance test shall be conducted after the twelve month rolling total hours of operation exceeds 4500 hours. The performance test shall be performed in accordance with EPA Reference Method 10.

C. All Operations

Should the Permittee desire to test or be required to test to determine compliance with any applicable standard, the Permittee shall contact the Control Officer for appropriate test methods.

ATTACHMENT C: APPLICABLE REGULATIONS

<u>Requirements Specifically Identified as Applicable:</u>

Pima County State Implementation Plan (SIP):

Rule 315	Roads and Streets
Rule 318	Vacant Lots and Open Spaces
Rule 321	Standards and Applicability
Rule 343	Visibility Limiting Standard

Code of Federal Regulations Title 40:

Part 60 Subpart KKKK	New Source Performance Standards for Stationary combustion Turbines
Part 60 Subpart GG	New Source Performance Standards for Stationary combustion Turbines
Part 60 Appendix B	Performance Specifications
Part 64	Compliance Assurance Monitoring
Part 75 Subpart F	Conversion Procedures
Part 75 Subpart G	Determination of CO Emissions
Part 75 Appendix A	Specifications and Test Procedures
Part 75 Appendix B	Quality Assurance and Quality Control

ADEQ Consent Order signed February 17, 2009

Pima County Code (PCC) Title 17, Chapter 17.16:

17.16.020	Noncompliance with Applicable Standards
17.16.030	Odor Limiting Standards
17.16.040	Standards and Applicability (Includes NESHAP)
17.16.050	Visibility Limiting Standards
17.16.060	Fugitive Dust Producing Activities
17.16.080	Vacant Lots and Open Spaces
17.16.090	Roads and Streets
17.16.100	Particulate Materials
17.16.110	Storage Piles
17.16.130	Applicability
17.16.160	Standards of Performance for Fossil-Fuel Fired Steam Generators and General Fuel Burning Equipment
17.16.165	Standards of Performance for Fossil-Fuel Fired Industrial and Commercial Equipment
17.16.310	Standards of Performance for Coal Preparation Plants
17.16.340	Standards of Performance for Stationary Rotating Machinery
17.16.430	Standards of Performance for Unclassified Sources

Installation Permit #1156 – October 14, 1981 by Arizona Department of Health Services

Tucson Electric Power
Irvington Generating Station
Air Quality Permit # 1052

ATTACHMENT D: EQUIPMENT LIST

I. Fossil Fuel Fired Steam Generators

Equipment ID	Description	Capacity	Serial Number	Make	Date of Manufacture, Installation, or Reconstruction
I1	Steam Electric Generating Unit	81 MW Net	18589	Combustion Engineering	1957
I2	Steam Electric Generating Unit	80 MW Net	19065	Combustion Engineering	1959
I3	Steam Electric Generating Unit	104 MW Net	19485	Combustion Engineering	1961
I4	Steam Electric Generating Unit	Coal: 110 MW Net Gas/Oil: 156 MW Net	75-19487	Foster Wheeler	1964

II. Stationary Rotating Machinery (including Stationary Turbines)

Equipment ID	Description	Capacity	Serial Number	Make	Date of Manufacture, Installation, or Reconstruction
IGT1	Simple cycle gas turbine generating unit	24 MW Net	17A2088-1	Westinghouse	1972
IGT2	Simple cycle gas turbine generating unit	24.5 MW Net	17A2086-1	Westinghouse	1972
IGT3	Simple cycle gas turbine generating unit	<25 MW Net	To be submitted upon purchase	To be submitted upon purchase	To be submitted upon purchase
IGT1A	Gas turbine diesel starter engine	635 hp	772267-3	Cummings	1972
IGT2A	Gas turbine diesel starter engine	635 hp	769853-3	Cummings	1972

III. Auxiliary Boiler

Equipment ID	Description	Capacity	Serial Number	Make	Date of Manufacture, Installation, or Reconstruction
IAUX	Auxiliary Boiler	57,000 lb/hr (steam)	23583	Babcock-Wilcox	1972

IV. Cooling Towers

Equipment ID	Description	Serial Number	Make	Date of Manufacture, Installation, or Reconstruction
I1E	Steam Unit Cooling Tower	FD90980	Fluor Products	1957
I2D	Steam Unit Cooling Tower	FD92580	Fluor Products	1959
I3D	Steam Unit Cooling Tower	663-3-10	Marley Co.	1961
I4E	Steam Unit Cooling Tower	6645-12-36-3	Marley Co.	1964

V. Air Pollution Controls

Equipment ID	Description	Serial/ Model Number	Make
I4BH	Baghouse to Unit I4	Project No. 83-1364, 65, 66	American Air Filter
A1	Flyash Silo A & B Collector	13-61-18999	Flex-Clean 100 CTBC 98 111G
A1A	Flyash Silo A & B Vent Collector	13-94-19000	Flex-Clean 100 WRBC-9611
A3	Flyash Storage Tank #4 Dust Collector	86410H1	Mikropul Corp.

VI. Continuous Emissions/Opacity Monitoring Systems

Unit	Pollutant/ Parameter	Method	Range
I1	Oxygen	Paramagnetic	0-21%
	NOx	Chemiluminesence	0-400 ppm
	Fuel Flow - Gas	Differential Pressure (DP)	0-9000 hscfh
	Fuel Flow - Oil	Positive Displacement (PDP)	0-50000 lb/hr
I2	Oxygen	Paramagnetic	0-21%
	NO_x	Chemiluminesence	0-400 ppm
	Fuel Flow - Gas	Differential Pressure (DP)	0-9000 hscfh
	Fuel Flow - Oil	Positive Displacement (PDP)	0-50000 lb/hr
I3	Oxygen	Paramagnetic	0-21%
	NO_X	Chemiluminesence	0-400 ppm
	Fuel Flow - Gas	Differential Pressure (DP)	0-12000 hscfh
	Fuel Flow - Oil	Positive Displacement (PDP)	0-75000 lb/hr
	Oxygen	Paramagnetic	0-21%
I4	NO_x	Chemiluminesence	0-400 ppm
	Sulfur Dioxide	U.V. Fluorescence	0-700 ppm
	Mass Flow	Constant temperature anemometer thermal array	3.29×10^7 scfh
	Opacity	Electro-optical, double pass	0-100%

VII. Emergency Generators

Equipment ID	Description	Capacity	Serial Number	Make/ Model	Date of Manufacture,
EGEN1	Non-NSPS Emergency Diesel Generator	349 HP (260 kW)	9NR03701	Caterpillar/ 3306	1999
EGEN2	**NSPS** Emergency Diesel Generator	636 HP (474 kW)	8CMAF6003ID	Kohler/ 400REOZDD	2008

ATTACHMENT E: INSIGNIFICANT ACTIVITIES

Equipment ID	Description	Capacity	Date of Manufacture, Installation, or Reconstruction
A6	Power Production - Flyash Latrine Vents	NA	NA
C2	Rotary Car Dumper Dust Collector	RFC-1178	Carter Day
C3	Live Coal Storage Dust Collector	RFC-1179	Carter Day
C5	Crusher Facility Dust Collector	RFC-1180	Carter Day
C6	Tower 4 Dust Collector	RFC-1181	Carter Day
C21	Power Production - Rotary Car Dumper Latrine Vent/Septic System	NA	NA
C22	Power Production - Crusher Tower Latrine Vent/Septic System	NA	NA
CHEM1	Power Production - North 12,000 gal 93% Sulfuric Acid Storage Tank	NA	NA
CHEM2	Power Production - North 12,000 gal 50% Liquid NaOH Storage Tank	NA	NA
CHEM3	Power Production - North Water Treatment Chemical Storage Bins/Barrels	NA	NA
CHEM4	Power Production - North Cooling Tower Treatment Room	NA	NA
CHEM5	Power Production - North Boiler Water Treatment Area	NA	NA
CHEM6	Power Production - South 12,000 gal 93% Sulfuric Acid Storage Tank	NA	NA
CHEM7	Power Production - South Water Treatment Chemical Storage Bins/Barrels	NA	NA
CHEM8	Power Production - South Cooling Tower Treatment Room	NA	NA
CHEM9	Power Production - South Boiler Water Treatment Area	NA	NA
CHEM11	Power Production -Environmental Laboratory Latrine Vent/Septic System	NA	NA
CHEM12	Power Production - Environmental Laboratory Fume Hood	NA	NA
CHEM13	Power Production - Water Laboratory Fume Hood (2)	NA	NA
CHEM14	Power Production –Environmental Laboratory Heater	NA	NA
CHEM15	Power Production - Boiler Feedwater Storage Tanks (6)	NA	NA
FH1	Fuel Oil Storage Tank #1 – Vertical Fixed Roof AST	524,072 gal	1957
FH2	Fuel Oil Storage Tank #2 – Vertical Fixed Roof AST	524,072 gal	1958
FH3	Fuel Oil Storage Tank #3 – Vertical Fixed Cone Roof AST	756,084 gal	1961
FH5	Water Storage Tank #5 – Vertical Fixed Roof AST	3,034,858 gal	1971
FH6	Fuel Oil Storage Tank #6 – Vertical Fixed Roof AST	3,034,858 gal	1971
FH7	Fuel Oil Storage Tank #7 – Vertical Fixed Roof AST	3,034,858 gal	1971
FH8	Fuel Oil Storage Tank #8 – Vertical Fixed Roof AST	10,612,951 gal	1972
FH9	Fuel Oil Storage Tank #9 – Vertical Fixed Roof AST	10,612,951 gal	1972
FH9	Power Production - Condensate Return Collection Sump Vents	NA	NA
FH10	Fuel Oil Storage Tank #10 –Vertical Fixed Roof AST	10,612,951 gal	1972
FH11	Fuel Oil Storage Tank #11 – Vertical Fixed Roof AST	3,034,858 gal	1972
FH12	Fuel Oil Storage Tank #12 – Vertical Fixed Roof AST	3,034,858 gal	1972
FH13	Fuel Oil Storage Tank #13 – Vertical Fixed Roof AST	3,034,858 gal	1972
FH14	Power Production - Condensate Return Collection Sump Vents	NA	NA

Equipment ID	Description	Capacity	Date of Manufacture, Installation, or Reconstruction
FH15	Power Production - Fuel Oil Unloading/Transfer/Pumping and Piping Facilities	NA	NA
FH16	Power Production - Waste Oil Drums	NA	NA
GS9	General Shop - Furnace 75 kBTU	NA	NA
GS10	General Shop - Latrine Vents	NA	NA
GS11	General Shop Paint Booth	NA	NA
I5	Power Production - Power Block Latrine Vents	NA	NA
I6	Power Production - Engineering Building Latrine Vents	NA	NA
I7	Power Production - Power Block Used Oil Storage Drums	NA	NA
I8	Power Production - Power Block Battery Rooms	NA	NA
I9	Power Production - Common Facilitites Battery Room	NA	NA
I11	Power Production - Mechanical Maintenance Flammable Storage cabinets	NA	NA
I12	Power Production - Switchyard Circuit Breakers/Transformers	NA	NA
I13	Lube Oil/Paint Storage Room	NA	NA
I14	Power Production - Maintenance Shop Welding Activities/Vents/ Solvent Tanks	NA	NA
I15	Electrical Shop Solvent Tank	NA	NA
I72	Power Production - #5 Fire/Dust Control Water Storage Tank 3,000,000 gal	NA	NA
I73	Power Production - Service Water Pressure/Storage Tank 150,000 gallons	NA	NA
I16-21, WH1-2, GS1-8, TRAN4-12	Miscellaneous hot water and space heaters	Misc.	Misc.
I1A	Power Production - Unit #1 Boiler Blowdown Flashtank	NA	NA
I1B	Turbine lube oil vapor extractor	NA	NA
I1C	Generator bearing drain vapor extractor	NA	NA
I1D	Generator bearing drain vacuum pump	NA	NA
I1F	Power Production - North Turbine Lube Oil Storage Tank	NA	NA
I1G	Power Production - Unit #1 Fuel Gas Piping	NA	NA
I1H	Power Production - Unit #1 Fuel Gas Vents	NA	NA
I1I	Power Production - Unit #1 Boiler Safety Relief Valve Vents	NA	NA
I1J	Power Production - Unit #1 Steam/Drain Vents	NA	NA
I1K	Power Production - Unit #1 Main Transformer	NA	NA
I1L	Power Production - Unit #1 Auxiliary Transformer	NA	NA
I2A	Power Production - Unit #2 Boiler Blowdown Flashtank	NA	NA
I2B	Turbine lube oil vapor extractor	NA	NA
I2C	Generator bearing drain vapor extractor	NA	NA
I2E	Power Production - Unit #2 Fuel Gas Piping	NA	NA
I2F	Power Production - Unit #2 Fuel Gas Vents	NA	NA
I2G	Power Production - Unit #2 Boiler Safety Relief Valve Vents	NA	NA
I2H	Power Production - Unit #2 Steam/Drain Vents	NA	NA
I2I	Power Production - Unit #2 Main Transformer	NA	NA
I2J	Power Production - Unit #2 Auxiliary Transformer	NA	NA
I3A	Power Production - Unit #3 Boiler Blowdown Flashtank	NA	NA
I3B	Turbine lube oil vapor extractor	NA	NA
I3C	Generator bearing drain vapor extractor	NA	NA
I3E	Power Production - South Turbine Lube Oil Storage Tank	NA	NA
I3F	Power Production - Unit #3 Fuel Gas Piping	NA	NA
I3G	Power Production - Unit #3 Fuel Gas Vents	NA	NA

Equipment ID	Description	Capacity	Date of Manufacture, Installation, or Reconstruction
I3H	Power Production - Unit #3 Boiler Safety Relief Valve Vents	NA	NA
I3I	Power Production - Unit #3 Steam/Drain Vents	NA	NA
I3J	Power Production - Unit #3 Main Transformer	NA	NA
I3K	Power Production - Unit #3 Auxiliary Transformer	NA	NA
I4A	Power Production - Unit #4 Boiler Blowdown Flashtank	NA	NA
I4B	Turbine lube oil vapor extractor	NA	NA
I4C	Generator bearing drain vapor extractor – 6508-G-13	NA	NA
I4D	Generator bearing drain vacuum pump	NA	NA
I4F	Power Production - Unit #4 Fuel Gas Piping	NA	NA
I4G	Power Production - Unit #4 Fuel Gas Vents	NA	NA
I4H	Power Production - Unit #4 Boiler Safety Relief Valve Vents	NA	NA
I4I	Power Production - Unit #4 Steam/Drain Vents	NA	NA
I4J	Power Production - Unit #4 Main Transformer	NA	NA
I4K	Power Production - Unit #4 Auxiliary Transformer	NA	NA
IGT1B	Turbine lube oil vapor extractor	0.5 hp/1A/230V	NA
IGT2B	Turbine lube oil vapor extractor	0.5 hp/1A/230V	NA
OH1	Operating Headquarters - HVAC Cooling Tower	NA	NA
OH1	ERTF Paint Booth	NA	NA
OH4	Operating Headquarters - Latrine Vents	NA	NA
OH5	Operating Headquarters - Training Center Latrine Vents	NA	NA
OH6	Operating Headquarters - Trailer Latrine Vents	NA	NA
OH73	Operating Headquarters Tool Room Solvent Tank	NA	NA
SS1	Servicenter - HVAC Cooling Tower	NA	NA
SS2	Servicenter - Reproduction Equipment	NA	NA
SS4	Servicenter - Latrine Vents	NA	NA
TRAN1	Transportation - New/Used Lubricating Oil Storage	NA	NA
TRAN13	Transportation - Latrine Vents	NA	NA
TRAN2	Transportation - Underground Diesel Storage Tank	15,000 gal	NA
Tank 19	Transportation – Aboveground Diesel Storage Tank	10,000 gal	NA
Tank 1	Transportation – Underground Gasoline Storage Tank	15,000 gal	1989
TRAN16	Transportation Steam Cleaner	NA	NA
WH4	WH4 Warehouse - Latrine Vents	NA	NA
WW1	Power Production - North Collection Sump-Boiler Blowdown.	NA	NA
WW2	Power Production - South Collection Sump (2) - Rain Runoff, Ash/Coal Area Washdown	NA	NA
WW3	Power Production - Bottom Ash Runoff Collection Sump	NA	NA
WW4	Power Production - Plant Waste Basin-Boiler BlowdownDemineralizer Regenerant	NA	NA
WW5	Power Production - Coal Pile Runof Basin- Rain Runoff, Ash/Coal Area Washdown	NA	NA
WW6	Power Production - Evaporation Basin (3) - Treated Wastewater from Plant Waste/Coal Pile Runoff Basin	NA	NA
WW7	Power Production - Waste Water Treatment Latrine Vent/Septic System	NA	NA
WW8	WW8 Power Production - Waste Water Treatment 5,000 gal 93% Sulfuric Acid Tank	NA	NA
WW9	Power Production - Waste Water Treatment 5,000 gal 50% Liquid NaOH Tank	NA	NA
WW10	Power Production - Waste Water Treatment Clarifier - Wastewater 140,000 gal	NA	NA

Equipment ID	Description	Capacity	Date of Manufacture, Installation, or Reconstruction
WW11	Power Production - Waste Water Treatment Scum Tank-Clarifier Scum for recycle 1170 gal	NA	NA
WW12	Power Production - Waste Water Treatment pH Adjustment Tank- Pretreated Wastewater 6768 gal	NA	NA
WW13	Power Production - Waste Water Treatment pH Adjustment Tank- Treated Wastewater 5000 gal	NA	NA
WW14	Power Production - Waste Water Treatment Chemical Mix Tank (2) - Alum 730 gal	NA	NA
WW15	Power Production - Waste Water Treatment Chemical Mix Tank (2) - Polymer 148 gal	NA	NA
N/A	Compact Linear Fresnel Reflector – Solar Steam Generator System	N/A	2011

ATTACHMENT F: PHASE II ACID RAIN PERMIT

I. STATEMENT OF BASIS

Statutory and Regulatory Authorities: In accordance with Arizona Revised Statutes, Title 49, Chapter 3, Article 2, Section 426.N, and Titles IV and V of the Clean Air Act, the Pima County Department of Environmental Quality issues this Phase II Acid Rain Permit pursuant to Section 17.12.365 of Title 17 of the Pima County Code.

II. SO_2 ALLOWANCE[1] ALLOCATIONS AND NOX REQUIREMENTS FOR EACH AFFECTED UNIT

[40 CFR Part 73 Table 2]

A. UNIT I1

Year:	2005 – 2009	2010 –
Annual SO_2 allowances	16 tons	14 tons
NOx Limits:	This unit is not subject to a NO_x limit under 40 CFR Part 76.	

B. UNIT I2

Year:	2005 – 2009	2010 –
Annual SO_2 allowances	28 tons	40 tons
NOx Limits:	This unit is not subject to a NO_x limit under 40 CFR Part 76.	

C. UNIT I3

Year:	2005 – 2009	2010 –
Annual SO_2 allowances	0 tons	2 tons
NOx Limits:	This unit is not subject to a NO_x limit under 40 CFR Part 76.	

D. UNIT I4

Year:	2005 – 2009	2010 –
Annual SO_2 allowances	2853 tons	2805 tons
NOx Limits:	Pursuant to 40 CFR Part 76, the Pima County Department of Environmental Quality approves a NOx emission limitation for UNIT I4. This unit's annual average NOx emission rate for each year, determined in accordance with 40 CFR Part 75, shall not exceed the applicable emission limitation, under 40 CFR Part 76.7(a)(2), of 0.46 lb/MMBTU for wall-fired boilers. In addition, this unit shall comply with all other applicable requirements of 40 CFR Part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.	

1. As defined under 40 CFR §72.2, "Allowance" means an authorization by the Administrator under the Acid Rain Program to emit up to one ton of sulfur dioxide during or after a specified calendar year.

The number of allowances actually held by an affected source in a unit account may differ from the number allocated by U.S. EPA. Neither of the aforementioned conditions necessitate a revision to the unit SO_2 allowance allocations identified in this permit (See 40 CFR 72.84).

III. ACID RAIN PERMIT APPLICATION

The Permittee, and any other owners or operators of the units at this facility, shall comply with the requirements contained in the two attached acid rain permit applications. These applications are:

A. Phase II Permit Application (OMB No. 2060-0258) signed by the Designated Representative on 12/12/95.

B. Phase II NOx Compliance Plan (OMB No. 2060-0258) signed by the Designated Representative on 12/15/97.

ATTACHMENT G: ALTERNATE OPERATING SCENARIO #1

I. APPLICABILITY – 40 CFR 60 Subpart KKKK

This alternate operating scenario #1 shall only apply to the turbine that will be identified as IGT3 upon purchase should the applicability date of IGT3 be subject to 40 CFR 60 Subpart KKKK. TEP-IGS shall notify PDEQ upon purchasing the turbine. The notification shall include all reporting requirements that are identified in this attachment.

II. GENERAL PROVISIONS

The following requirements apply to the operation, maintenance, recordkeeping and testing of Unit IGT3 and its associated monitoring systems in accordance with 40 CFR Part 60, Subpart A – General Provisions. These requirements are in addition to any applicable requirements in the General Provisions in Part A of this permit, unless Attachment G is more stringent.

A. Mailing Address

All requests, reports, applications, submittals, and other communications to the Administrator and Control Officer pursuant to 40 CFR Part 60 shall be submitted in duplicate to the Administrator and Control Officer at the following addresses: [40 CFR §60.4(a)]

Director, Air Division	Director
U.S. Environmental Protection Agency	Pima County Department of Environmental Quality
75 Hawthorne Street	33 North Stone Avenue, Suite 730
San Francisco, CA 94105	Tucson, AZ 85701

B. Notification and Recordkeeping

1. The Permittee shall furnish the Control Officer written notification as follows: [40 CFR 60.7(a)]

   a. A notification of the date of construction of Unit IGT3 is commenced postmarked no later than 30 days after such date (date of construction). [40 CFR 60.7(a)(1)]

   b. A notification of the actual date of initial startup of Unit IGT3 postmarked within 15 days of after such date (date of initial startup). [40 CFR 60.7(a)(3)]

   c. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Control Officer may request additional relevant information subsequent to this notice. [40 CFR 60.7(a)(4)]

d. A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR 60.13(c) postmarked not less than 30 days prior to such date. [40 CFR 60.7(a)(5)]

e. A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1). The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date. [40 CFR 60.7(a)(6)]

f. A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5). This notification shall be postmarked not less than 30 days prior to the date of the performance test. [40 CFR 60.7(a)(7)]

2. The Permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. [40 CFR 60.7(b)]

3. The Permittee shall submit excess emissions and monitoring systems performance reports and/or summary report form to the Control Officer semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Control Officer, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: [40 CFR 60.7(c), 40 CFR 60.4375(a), 40 CFR 60.4395 & PCC 17.12.040.B]

a. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions and the process operating time during the reporting period. [40 CFR 60.7(c)(1)]

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted. [40 CFR 60.7(c)(2)]

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. [40 CFR 60.7(c)(3)]

d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report. [40 CFR 60.7(c)(4)]

4. The summary report form submitted by the Permittee shall contain the information and be in the format shown in 40 CFR 60.7(d) figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at IGT3. [40 CFR 60.7(d)]

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 CMS 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 II.B.3 of Attachment G need not be submitted unless requested by the Administrator.

[40 CFR 60.7(d)(1)]

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 CMS 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 II.B.3 of Attachment G shall both be submitted. [40 CFR 60.7(d)(2)]

5. The Permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows: [40 CFR 60.7(f)]

a. If the Permittee is required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required in II.B.5 of Attachment G, the Permittee shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard. [40 CFR 60.7(f)(1)]

b. If the Permittee is required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under II.B.5 of Attachment G the Permittee shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator. [40 CFR 60.7(f)(2)]

c. The Administrator or Control Officer, upon notification to the source, may require the Permittee to maintain all measurements as required by II.B.5 of Attachment G, if the Administrator or Control Officer determines these records are required to more accurately assess the compliance status of the affected source. [40 CFR 60.7(f)(3)]

C. Performance Tests

1. Within 60 days after achieving the maximum production rate at which IGT3 will be operated, but not later than 180 days after initial startup of IGT3 and at such other times as may be required by the Control Officer under section 114 of the Act, the Permittee shall conduct emissions performance test(s) for NOx and SO_2, and furnish the Control Officer a written report of the results of such performance test(s). [40 CFR 60.8(a)]

D. Compliance with Standards and Maintenance Requirements

1. At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate IGT3 including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Control Officer which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. [40 CFR 60.11(d)]

2. For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any standard in 40 CFR Part 60, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. [40 CFR 60.11(g)]

E. Circumvention

The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission, which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with opacity standard or with a standard, which is based on the concentration of a pollutant in the gases discharged to the atmosphere. [40 CFR 60.12]

F. General Notification and Reporting Requirements

The Permittee shall comply with the “General Notification and Reporting Requirements” found in 40 CFR 60.19. [40 CFR 60.19]

III SPECIFIC CONDITIONS

A. Operational Limitations

The Permittee shall not cause or allow the combustion of any fuel in Unit IGT3 other than pipeline quality natural gas. [PCC 17.12.190.B]

B. Nitrogen Oxide

1. Emission Limitations/Standards [PCC 17.12.180.A.2]

a. The Permittee shall not allow the NOx concentration to exceed 25 ppm at 15 percent O_2 or 1.2 pound per megawatt-hour as determined by the NOx and diluent CEMS based on a 4-hour rolling average. [40 CFR 60.4320 Table 1, 60.4325 & 60.4380(b)(1)]

b. The Permittee shall not allow the total combined emissions of NOx from Unit IGT3 to equal or exceed 40 tons per year, calculated as a 12-month rolling total. [PCC 17.12.190.B]
[Material Permit Condition]

2. Air Pollution Control Equipment

The Permittee must operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing NOx emissions at all times including during startup, shutdown, and malfunction. [40 CFR 60.4333(a)]**[Material Permit Condition]**

3. Monitoring, Recordkeeping and Reporting Requirements [PCC 17.12.180A.3, A.4 & A5]

a. The Permittee must install and certify each NOx diluent CEMS according to 40 CFR 60 Appendix B, Performance Specification 2 (PS 2), except the 7-day calibration drift is based on unit operating days, not calendar days and the relative accuracy test audit (RATA) shall be performed in lb/ MMBtu basis. [40 CFR 60.4345(a)]
[Material Permit Condition]

b. The Permittee shall demonstrate compliance with the NOx emission limitation in III.B.1.a of Attachment G as follows:

i. Install, calibrate, maintain, and operate a continuous monitoring system (CMS) to monitor and record the fuel consumption and the ratio of water to fuel being fired in Unit IGT3 when burning a fuel that requires water injection for compliance; or [40 CFR 60.4335(a)]

ii. Alternatively, the Permittee shall in accordance with III.E.1 of Attachment G. install, certify, maintain and operate a continuous emission monitoring system (CEMS) consisting of a NOx monitor, and a diluent gas (CO_2 or O_2) monitor; to determine the hourly NOx emission rate in parts per million (ppm) or pounds per million British thermal units (lb/MMBtu); and [40 CFR 60.4335(b)(1)]

iii. If complying with the output-based standard, the Permittee shall install, calibrate, maintain, and operate a fuel flow meter (or flow meters) to continuously measure the heat input to IGT3; and [40 CFR 60.4335(b)(2)]

iv. If complying with the output-based standard, the Permittee shall install, calibrate, maintain, and operate a watt meter (or meters) to continuously measure the gross electrical output of IGT3 in megawatt hours. [40 CFR 60.4335(b)(3)]

c. The Permittee shall install, calibrate, maintain and operate each watt meter, steam flow meter and each pressure or temperature measurement device according to manufacturer's instructions. [40 CFR 60.4345(d)]

d. Annual NOx Emission Limit

To demonstrate compliance with the annual NOx emission limit in III.B.1.b of Attachment G, the Permittee shall comply with the continuous emission system monitoring, recordkeeping and reporting provisions in III.E.2 of Attachment G.

4. Performance Testing [PCC 17.12.180.A.3]

a. The Permittee shall perform the initial performance test as required by 40 CFR 60.8: [40 CFR 60.4405]

b. The Permittee shall conduct annual performance tests (no more than 14 calendar months following the previous performance test). [40 CFR 60.4400(a)]

c. The Permittee shall use EPA Method 7E or EPA Method 20 for III.B.1.a of Attachment G. For units complying with the output based standard, the Permittee shall concurrently measure the stack gas flow rate using EPA Methods 1 and 2, and measure and record the electrical and thermal output from IGT3. Then, use the following equation to calculate the NOx emission rate:

$$E = \frac{1.194 \times 10^{-7} * (NOx)_c * Q_{std}}{P} \quad \text{where:} \qquad \text{(Eq. 5)}$$

E = NOx emission rate, in lb/MWh
1.194×10^{-7} = conversion constant, in lb/ dscf-ppm
$(NOx)_c$ = average NOx concentration for the run, in ppm
Q_{std} = stack gas volumetric flow rate, in dscf/ hr
P = gross electrical and mechanical energy output of the combustion turbine, in MW (for simple-cycle operation), for combined-cycle operation, the sum of all electrical and mechanical output from the combustion and steam turbines, or, for combined heat and power operation, the sum of all electrical and mechanical output from the combustion and steam turbines plus all useful recovered thermal output not used for additional electric or mechanical generation, in MW, calculated according to 40 CFR 60.4350(f)(2).

d. The Permittee shall conduct NOx emission performance test in accordance with 40 CFR 60.4400 or 40 CFR 60.4405.

C. Sulfur Dioxide

1. Emission Limitations/Standards

a. The Permittee shall not burn in Unit IGT3, any fuel that contains sulfur in excess of 0.060 pounds SO_2 per million British thermal unit (lb of SO_2/MMBtu) heat input.
[40 CFR 60.4365][PCC 17.12.190.B]
[Material Permit Condition]

b. The Permittee shall not allow the total combined emissions of SO_2 from Unit IGT3 to equal or exceed 40 tons per year, calculated as a 12-month rolling total. [PCC 17.12.190.B]
[Material Permit Condition]

2. Monitoring, Recordkeeping and Reporting Requirements [PCC 17.12.180A.3, A.4 & A5]

a. The Permittee shall be exempted from monitoring the total sulfur content of fuel combusted in IGT3, by keeping readily available for inspection, a paper or electronic record of a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for natural gas use is 20 grains of sulfur or less per 100 standard cubic feet and has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. [40 CFR §60.4365(a)]

b. To demonstrate compliance with III.C.1.b of Attachment G, the Permittee shall comply with the continuous emission monitoring, recordkeeping, and reporting requirements in III.E.2 of Attachment G.

D. Carbon Monoxide

1. Emission Limitations/Standards

The Permittee shall not allow the total combined emissions of carbon monoxide (CO) from IGT3 to equal or exceed 100 tons per year, calculated as a 12-month rolling total. [PCC 17.12.190.B]

[Material Permit Condition]

2. Monitoring, Recordkeeping and Reporting Requirements [PCC 17.12.180.A.3, A.4 & A.5]

a. The Permittee shall install, calibrate, maintain and operate and quality-assure a Continuous Emission Monitoring System (CEMS) consisting of CO and O2 or CO2 monitors for measuring CO emissions and diluent from IGT3.

[Material Permit Condition]

b. The Permittee shall install, calibrate, maintain and operate the in-line fuel flowmeter monitoring systems for determining the natural gas input rate to IGT3 for each operating hour according to the manufacturer's instructions. [40 CFR 60.4345(c)]

[Material Permit Condition]

c. To demonstrate compliance with the annual CO emission limit in III.D.1 of Attachment G, the Permittee shall comply with the CEMS monitoring, recordkeeping, and reporting requirements in Condition III.E.2 of Attachment G.

E. Continuous Emissions Monitoring Systems (CEMS) [40 CFR §60.13, PCC 17.12.050.H.3]

1. New Source Performance Standards for Continuous Emission Monitoring Systems

To demonstrate compliance with III.B.1.a of Attachment G the Permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) and data acquisition handling system (DAHS) to calculate a four hour rolling average NOx emission rate.

a. The Permittee shall comply with the following requirements in the General Provisions of 40 CFR 60 for each CEMS unit installed:

i. The CEMS and DAHS monitoring and recording devices shall be installed and operational prior to conducting initial performance test. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device. [40 CFR 60.13 (b)]

ii. The Permittee shall automatically 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 a written procedure. The zero and span must, as a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in 40 CFR, Part 60, appendix B. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified.

[40 CFR 60.13 (d)(1)]

iii. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under II.B.5 of Attachment G, the CEMS shall be in continuous operation and shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

[40 CFR 60.13 (e) & (e)(2)]

iv. The CEMS devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 (III.E.1.b of Attachment G) shall be used. [40 CFR 60.13 (f)]

v. The Permittee shall reduce all data to 1-hour averages as defined in 40 CFR 60.2. 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under III.E.1.a.v of Attachment G. The data may be recorded in reduced or non-reduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used to specify the emission limit. [40 CFR 60.13 (h)]

vi. The Permittee shall meet the notification and recordkeeping requirements in II.B.1.d and II.B.5 of Attachment G.

b. The Permittee shall comply with the following requirements in the Performance Specifications of 40 CFR 60 Appendix B, for each CEMS unit installed:

i. The CEMS installation and measurement location specification shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.1.

ii. Pretest preparation shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.2.

iii. Calibration drift test procedure shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.3.

iv. Relative accuracy test procedure shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.4.

v. Reporting requirements shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.5.

vi. Analytical procedures shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 11.0.

vii. Calculation and data analysis shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 12.0.

viii. Method performance shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 13.0.

ix. Alternative Procedures shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 16.0.

x. References are located in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 17.0.

xi. Tables, Diagrams, Flowcharts, and Validation data necessary for NOx CEMS testing are located in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 18.0.

xii. Specifications and test procedures for O_2 and CO_2 CEMS in Stationary Systems shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 3.

xiii. Specifications and Test Procedures for CO CEMS in Stationary Sources shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 4.

c. The Permittee shall maintain and operate each CEMS unit in accordance with the following:

i. As specified in III.E.1.a.iii of Attachment G, during each full unit operating hour, both the NOx monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point shall be obtained with each monitor for each quadrant of the hour in which a unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NOx emission rate for the hour. [40 CFR 60.4345(b)]

ii. All CEMS data must be reduced to hourly averages as specified III.E.1.a.v of Attachment G. [40 CFR 60.4350(a)]

iii. For each unit operating hour in which a valid hourly average, as described in III.E.1.c.i of Attachment G, is obtained for both NOx and diluent monitors, the DAHS must calculate and record the hourly NOx emission rate in units of ppm or lb/ MMBtu, using the appropriate equation from method 19 in appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations. [40 CFR 60.4350(b)]

iv. Correction of measured NOx concentrations to 15 percent O_2 is not allowed. [40 CFR 60.4350(c)]

v. The Permittee shall reduce all required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data to hourly averages. [40 CFR 60.4350(e)]

vi. The Permittee shall calculate the hourly average NOx emission rates, in units of either ppm (parts per million) for units complying with the concentration limit or in pounds per megawatt hour (lb/MWh) for units complying with the output based standard by using the simple cycle operation equation below: [40 CFR 60.4350(f)]

$$E = \frac{(NO_x)_h * (HI)_h}{P} \quad \text{where:} \qquad \text{(Equation 1)}$$

E = hourly NO_x emission rate, in lb/MWh.
$(NO_x)_h$ = hourly NOx emission rate, in lb/MMBtu.
$(HI)_h$ = hourly heat input rate to the unit, in MMBtu/h, measured using the fuel flow meter(s), e.g., calculated using Equation D-15a in appendix D to 40 CFR Part 75.
P = gross energy output of the combustion turbine in MW.

vii. The Permittee shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in III.B.3.a, III.D.2.b and III.B.3.c. [40 CFR 60.4345(e)]

2. Monitoring, Recordkeeping, and Reporting Requirements for Annual NOx, SO_2, and CO Emission Limits [PCC 17.12.180.A.3, A.4 & A.5]

a. For the purpose of compliance demonstration with annual NOx, and CO emission limits, the Permittee shall utilize the NOx, CO, diluent CEMS on Unit IGT3 in conjunction with the Data Acquisition and Handling System (DAHS) and fuel flow rate monitoring systems. A default value for SO_2 concentration will be calculated using equation 3 below. The DAHS will calculate emissions of NOx, SO_2 and CO in pounds per hour (lb/hr), tons per month, and tons per year, calculated monthly as a 12-month rolling total. The Permittee shall use the procedures in Method 19 of 40 CFR 60 Appendix A as applicable to calculate NOx, and CO mass emission rates.

b. The Permittee shall calculate SO_2 mass emission rates for Unit IGT3 using Equation 3 and 3A below:

$$ER = (2.0 / 7000) \times 10^6 \times (S_{total} / GCV) \quad \text{where:} \qquad \text{(Equation 3)}$$

ER = Default SO2 emission rate for natural gas combustion, lb/mmBtu
S_{total} = Total sulfur content of the natural gas from a valid purchase agreement, tariff agreement, or sampling, gr/100 scf
GCV = Gross calorific value of the natural gas from a valid purchase agreement, tariff agreement, or sampling, Btu/100 scf
7,000 = Conversion of grains/100 scf to lb/100 scf
10^6 = Conversion factor (Btu/mmBtu)

$$SO_2 \text{ rate} = ER \times HI \text{ rate} \quad \text{where:} \qquad \text{(Equation 3A)}$$

SO_2 rate = Hourly mass emission rate of SO_2, lb/hr
ER = SO_2 default emission rate of 0.06 lbs/MMBtu

HI rate = Hourly heat input rate, MMBtu/hr

c. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for NOx, CO, and diluent concentration or heat input rate.

d. During CEMS system downtime, the Permittee shall implement the missing data procedures for NOx and CO shown in 40 CFR Part 75 Subpart D – Missing Data Substitution Procedures

e. Each calendar month during which the combined 12-month rolling total for the NOx, emission rate from Unit IGT3 exceeds 40 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with XI.A of Part A.

f. Each calendar month during which the combined 12-month rolling total for the SO_2, emission rate from Unit IGT3, exceeds 40 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with XI.A of Part A.

g. Each calendar month during which the combined 12-month rolling total for the CO emission rate from Unit IGT3, exceeds 100 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with XI.A of Part A.

h. Each individual day and 12-month rolling total for NOx, SO_2, and CO emission rates in the reporting period shall be included in the semiannual compliance certification required by VII of Part A.

i. Quality Assurance Requirements for Natural Gas Fuel Flow meters

   i. Each transmitter or transducer shall be calibrated by equipment that has a current certificate of traceability to NIST standards at least once every four calendar quarters in which a unit operated on natural gas for 168 hours or more during each quarter but not less than once every three years. The Permittee shall check the calibration of each transmitter or transducer by comparing its readings to that of the NIST traceable equipment at least once at the following levels: the zero-level, and at least two other upscale levels (e.g., "mid" and "high"), such that the full range of transmitter or transducer readings corresponding to normal unit operation is represented.

   ii. The Permittee shall calculate the accuracy of each transmitter or transducer at each level tested, using the following equation:

$$ACC = \frac{|R - T|}{FS} \times 100 \qquad \text{where:}$$

ACC = Accuracy of the transmitter or transducer as a percentage of full-scale.
R = Reading of the NIST traceable reference value (in milliamperes, inches of
water, psi, or degrees).
T = Reading of the transmitter or transducer being tested (in
milliamperes, inches of water, psi, or degrees, consistent with the

units of measure of the NIST traceable reference value).

FS = Full-scale range of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

iii. If each transmitter or transducer meets an accuracy of ± 1.0 percent of its full-scale range at each level tested, the fuel flow meter accuracy of 2.0 percent is considered to be met at all levels. If however, one or more of the transmitters or transducers does not meet an accuracy of ± 1.0 percent of full-scale at a particular level, then the Permittee may demonstrate that the fuel flow meter meets the total accuracy specification of 2.0 percent at that level by using one of the following alternative methods. If, at a particular level, the sum of the individual accuracies of the three transducers is less than or equal to 4.0 percent, the fuel flow meter accuracy specification of 2.0 percent is considered to be met for that level. Or, if at a particular level, the total fuel flow meter accuracy is 2.0 percent or less, when calculated in accordance with Part 1 of American Gas Association Report No. 3, General Equations and Uncertainty Guidelines, the flow meter accuracy requirement is considered to be met for that level.

iv. If during a transmitter or transducer accuracy test the flow meter accuracy specification of 2.0 percent is not met at any of the levels tested, the Permittee shall repair or replace the transmitter(s) or transducer(s) as necessary until the flow meter accuracy specification has been achieved at all levels. (Note that only transmitters or transducers which are repaired or replaced need to be re-tested; however, the re-testing is required at all three measurement levels to ensure that the flow meter accuracy specification is met at each level).

v. For orifice-, nozzles, and venturi type flow meters, the Permittee shall perform a primary element inspection for damage and corrosion at least once every 12 calendar quarters in which a unit operated on natural gas for 168 hours or more during each quarter but not less than once during the term of this permit. If damage and/or corrosion are found, the Permittee shall replace the flow meter or restore the damaged or corroded flow meter to “as new” condition.

vi. The Permittee shall log in ink, or in an electronic format the date that the calibration and inspection was conducted, the results of the calibration or inspection, and corrective action taken if needed.

ATTACHMENT H: ALTERNATE OPERATING SCENARIO #2

I. APPLICABILITY – 40 CFR 60 Subpart GG

This alternate operating scenario #2 shall only apply to the turbine that will be identified as IGT3 upon purchase should the applicability date of IGT3 be subject to 40 CFR 60 Subpart GG. TEP-IGS shall notify PDEQ upon purchasing the turbine. The notification shall include all reporting requirements that are identified in this attachment.

II. GENERAL PROVISIONS

The following requirements apply to the operation, maintenance, recordkeeping and testing of Unit IGT3 and its associated monitoring systems in accordance with 40 CFR Part 60, Subpart A – General Provisions. These requirements are in addition to any applicable requirements in the General Provisions in Part A of this permit, unless Attachment H is more stringent.

A. Mailing Address

All requests, reports, applications, submittals, and other communications to the Administrator and Control Officer pursuant to 40 CFR Part 60 shall be submitted in duplicate to the Administrator and Control Officer at the following addresses: [40 CFR §60.4(a)]

Director, Air Division	Director
U.S. Environmental Protection Agency	Pima County Department of Environmental Quality
75 Hawthorne Street	33 North Stone Avenue, Suite 700
San Francisco, CA 94105	Tucson, AZ 85701

B. Notification and Recordkeeping

1. The Permittee shall furnish the Control Officer written notification as follows: [40 CFR 60.7(a)]

   a. A notification of the date of construction of Unit IGT3 is commenced postmarked no later than 30 days after such date (date of construction). [40 CFR 60.7(a)(1)]

   b. A notification of the actual date of initial startup of Unit IGT3 postmarked within 15 days of after such date (date of initial startup). [40 CFR 60.7(a)(3)]

   c. A notification of any physical or operational change to an existing facility which may increase the emission rate of any air pollutant to which a standard applies, unless that change is specifically exempted under an applicable subpart or in 40 CFR 60.14(e). This notice shall be postmarked 60 days or as soon as practicable before the change is commenced and shall include information describing the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change. The Control Officer may request additional relevant information subsequent to this notice. [40 CFR 60.7(a)(4)]

d. A notification of the date upon which demonstration of the continuous monitoring system performance commences in accordance with 40 CFR 60.13(c) postmarked not less than 30 days prior to such date. [40 CFR 60.7(a)(5)]

e. A notification of the anticipated date for conducting the opacity observations required by 40 CFR 60.11(e)(1). The notification shall also include, if appropriate, a request for the Administrator to provide a visible emissions reader during a performance test. The notification shall be postmarked not less than 30 days prior to such date. [40 CFR 60.7(a)(6)]

f. A notification that continuous opacity monitoring system data results will be used to determine compliance with the applicable opacity standard during a performance test required by 40 CFR 60.8 in lieu of Method 9 observation data as allowed by 40 CFR 60.11(e)(5). This notification shall be postmarked not less than 30 days prior to the date of the performance test. [40 CFR 60.7(a)(7)]

2. The Permittee shall maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility; any malfunction of the air pollution control equipment; or any periods during which a continuous monitoring system or monitoring device is inoperative. [40 CFR 60.7(b)]

3. The Permittee shall submit excess emissions and monitoring systems performance reports and/or summary report form to the Control Officer semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Control Officer, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: [40 CFR 60.7(c) & PCC 17.12.040.B]

a. The magnitude of excess emissions computed in accordance with 40 CFR 60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions and the process operating time during the reporting period. [40 CFR 60.7(c)(1)]

b. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted. [40 CFR 60.7(c)(2)]

c. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments. [40 CFR 60.7(c)(3)]

d. When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report. [40 CFR 60.7(c)(4)]

4. The summary report form submitted by the Permittee shall contain the information and be in the format shown in 40 CFR 60.7(d) figure 1 unless otherwise specified by the Administrator. One summary report form shall be submitted for each pollutant monitored at IGT3. [40 CFR 60.7(d)]

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 CMS 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 II.B.3 of Attachment H need not be submitted unless requested by the Administrator.
[40 CFR 60.7(d)(1)]

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 CMS 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 II.B.3 of Attachment H shall both be submitted. [40 CFR 60.7(d)(2)]

5. The Permittee shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as follows: [40 CFR 60.7(f)]

   a. If the Permittee is required to install a continuous emissions monitoring system (CEMS) where the CEMS installed is automated, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. An automated CEMS records and reduces the measured data to the form of the pollutant emission standard through the use of a computerized data acquisition system. In lieu of maintaining a file of all CEMS subhourly measurements as required in II.B.5 of Attachment H, the Permittee shall retain the most recent consecutive three averaging periods of subhourly measurements and a file that contains a hard copy of the data acquisition system algorithm used to reduce the measured data into the reportable form of the standard. [40 CFR 60.7(f)(1)]

   b. If the Permittee is required to install a CEMS where the measured data is manually reduced to obtain the reportable form of the standard, and where the calculated data averages do not exclude periods of CEMS breakdown or malfunction. In lieu of maintaining a file of all CEMS subhourly measurements as required under II.B.5 of Attachment H the Permittee shall retain all subhourly measurements for the most recent reporting period. The subhourly measurements shall be retained for 120 days from the date of the most recent summary or excess emission report submitted to the Administrator. [40 CFR 60.7(f)(2)]

   c. The Administrator or Control Officer, upon notification to the source, may require the Permittee to maintain all measurements as required by II.B.5 of Attachment H, if the Administrator or Control Officer determines these records are required to more accurately assess the compliance status of the affected source. [40 CFR 60.7(f)(3)]

C. Performance Tests

Within 60 days after achieving the maximum production rate at which IGT3 will be operated, but not later than 180 days after initial startup of IGT3 and at such other times as may be required by the Control Officer under section 114 of the Act, the Permittee shall conduct emissions performance test(s) for NOx and SO_2, and furnish the Control Officer a written report of the results of such performance test(s). [40 CFR 60.8(a)]

D. Compliance with Standards and Maintenance Requirements

1. At all times, including periods of startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate IGT3 including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Control Officer which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. [40 CFR 60.11(d)]

2. For the purpose of submitting compliance certifications or establishing whether or not the Permittee has violated or is in violation of any standard in 40 CFR Part 60, nothing shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed. [40 CFR 60.11(g)]

E. Circumvention

The Permittee shall not build, erect, install, or use any article, machine, equipment or process, the use of which conceals an emission, which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with opacity standard or with a standard, which is based on the concentration of a pollutant in the gases discharged to the atmosphere. [40 CFR 60.12]

F. General Notification and Reporting Requirements

The Permittee shall comply with the "General Notification and Reporting Requirements" found in 40 CFR 60.19. [40 CFR 60.19]

III SPECIFIC CONDITIONS

A. Operational Limitations

The Permittee shall not cause or allow the combustion of any fuel in Unit IGT3 other than pipeline quality natural gas. [PCC 17.12.190.B]

B. Nitrogen Oxide

1. Emission Limitations/Standards [PCC 17.12.180.A.2]

a. On and after the date of the performance test required by II.C of Attachment H is completed, the Permittee shall not cause to be discharged into the atmosphere from Unit IGT3) any gases which contain nitrogen oxides (NO_x) in excess of:
[40 CFR 60.332(a)(1) & 60.332(b)]
[Material Permit Condition]

$$STD = 0.0075 \frac{(14.4)}{Y} + F$$

where:

STD = allowable ISO corrected (if required as given in 40 CFR 60.335(b)(1)) NO_x emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NO_x emission allowance for fuel-bound nitrogen = 0.

For Gas Turbine Units IGT3, STD = 75 ppmv at 15% oxygen

b. The Permittee shall not allow the total combined emissions of nitrogen oxides from Unit IGT3 to equal or exceed 40 tons per year, calculated as a 12-month rolling total.

[PCC 17.12.190.B]

[Material Permit Condition]

2. Air Pollution Control Equipment

At all times, including during startup, shutdown, and malfunction, the Permittee shall, to the extent practicable, maintain and operate Unit IGT3 including associated air pollution control equipment and monitoring equipment in a manner consistent with good air pollution control practices for minimizing NOx emissions. [40 CFR 60.11(d)][PCC 17.12.180.A.2]

[Material Permit Condition]

3. Monitoring, Recordkeeping and Reporting Requirements [PCC 17.12.180A.3, A.4 & A5]

a. The Permittee shall install, certify, maintain, operate and quality-assure Continuous Emission Monitoring Systems (CEMS) consisting of NO_x and O_2 (or CO_2) monitors for measuring NO_x emissions from Gas Turbine Unit IGT3. [PCC 17.12.180.A.2]

[Material Permit Condition]

b. The Permittee shall install, calibrate, maintain, and operate fuel flow rate monitoring systems for determining the natural gas input rate to gas turbine unit IGT3 for each operating hour. The fuel flow rate monitoring system shall be calibrated and quality-assured in accordance with III.E.2.i of Attachment H. [PCC 17.12.180.A.2]

[Material Permit Condition]

c. New Source Performance Standards (NSPS) Provisions

The Permittee shall comply with the following requirements contained in 40 CFR Part 60 Subpart GG as amended on July 8, 2004.

i. The Permittee shall comply with the NO_x emission limitation in III.B.1.a.of Attachment H by using one of the following methods:

(A) Install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water to fuel being fired in Unit IGT3. [40 CFR 60.334(a)]

(B) Utilize the CEMS required by III.B.3.a of Attachment H and demonstrate compliance in accordance with III.B.3.c.iii of Attachment H. [40 CFR 60.334(d)]

ii. If the Permittee elects to demonstrate compliance with III.B.1.a. of Attachment H by continuously monitoring the water to fuel ratio as provided by III.B.3.c.i.(A) of Attachment H, the following requirements shall apply:

(A) The water to fuel ratio in III.B.3.c.i.(A) of Attachment H shall be monitored during the performance test required under 40 CFR 60.8 to establish acceptable values and ranges. The Permittee may supplement the performance test data with engineering analyses, design specifications, manufacturer's recommendations and other relevant information to define the acceptable parametric ranges more precisely. The Permittee shall develop and keep on-site a parameter monitoring plan which explains the procedures used to document proper operation of the NO_x emission controls. The plan shall include the parameter(s) monitored and the acceptable range(s). Any supplemental data such as engineering analyses, design specifications, manufacturer’s recommendations and other relevant information shall be included in the monitoring plan. [40 CFR 60.334(g)]

(B) The Permittee shall submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). Excess emissions shall be reported for all periods of Unit IGT3 operation, including startup, shutdown and malfunction. Excess emissions and monitor downtime that shall be reported are defined as follows: [40 CFR 60.334(j) & (j)(1)(i)]

(1) An excess emission shall be any unit operating hour for which the average water to fuel ratio, as measured by the continuous monitoring system, falls below the acceptable water to fuel ratio needed to demonstrate compliance with III.B.1.a. of Attachment H, as established during the performance test required in 40 CFR 60.8. Any unit operating hour in which no water is injected into the turbine shall also be considered an excess emission.

(2) A period of monitor downtime shall be any unit operating hour in which water is injected into the turbine, but the essential parametric data needed to determine the water to fuel ratio are unavailable or invalid.

(3) Each report shall include the average water to fuel ratio, average fuel consumption, ambient conditions (temperature, pressure, and humidity) and gas turbine load. The Permittee is not required to report ambient conditions if opting to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii).

iii. If the Permittee elects to demonstrate compliance with III.B.1.a. of Attachment H using CEMS as provided by III.B.3.c.(i)(B) of Attachment H, the following requirements shall apply:

(A) The NO_x and diluent CEMS shall be installed, certified, maintained and operated as follows:

(1) Each CEMS must be installed and certified according to Performance Specification 2 and 3 (for diluent) of 40 CFR Part 60, Appendix B, except the 7-day calibration drift is based on unit operating days, not calendar days. [40 CFR 60.334(b)(1)]

(2) The NO_x and diluent CEMS on Unit IGT3 shall be installed and operational prior to conducting performance tests as required by III.B.4 of Attachment H. [40 CFR 60.13(b)]

(3) During each full unit operating hour, each monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required to validate the hour.

[40 CFR 60.334(b)(2)]

(4) For the purpose of identifying excess emissions, CEMS data must be reduced to hourly averages as specified in 40 CFR 60.13(h).

[40 CFR 60.334(b)(3)]

(5) For each unit operating hour in which a valid hourly average is obtained for both NO_x and diluent, the data acquisition and handling system must calculate and record the hourly NO_x emissions in the units of the applicable NO_x emission standard under III.B.1.a. of Attachment H of this Attachment. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2, a diluent cap value of 19.0 percent O_2 may be used in the emission calculations.

[40 CFR 60.334(b)(3)(i)]

(6) A worst case ISO correction factor may be calculated and applied using historical ambient data in accordance with the procedures in 40 CFR 60.334(b)(3)(ii). [40 CFR 60.334(b)(3)(ii)]

(B) The Permittee shall submit reports of excess emissions and monitor downtime in accordance with 40 CFR 60.7(c). The reports shall be postmarked by the 30th day following the end of each calendar quarter. Excess emissions shall be reported for all periods of unit operation, including startup, shutdown and malfunction. Periods of excess emissions and monitor downtime that shall be reported are defined as follows: [40 CFR 60.334(j)(1)(iii)]

(1) An hour of excess emissions shall be any unit operating hour in which the 4-hour rolling average NO_x concentration exceeds the applicable emission limit in Condition III.B.1.a of Attachment H. A 4-hour rolling average NO_x concentration is the arithmetic average of the average NO_x concentration measured by the CEMS for a given hour (corrected

to 15 percent O_2 and, to ISO standard conditions) and the three unit operating hour average NO_x concentrations immediately preceding that unit operating hour.

(2) A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for either NO_x concentration or diluent (or both).

(3) Each report shall include the ambient conditions (temperature, pressure, and humidity) at the time of the excess emission period. The Permittee is not required to report ambient conditions if opting to use the worst case ISO correction factor as specified in 40 CFR 60.334(b)(3)(ii).

d. Annual NOx Emission Limit

To demonstrate compliance with the annual NOx emission limit in III.B.1.b of Attachment H, the Permittee shall comply with the continuous emission system monitoring, recordkeeping and reporting provisions in III.E.2 of Attachment H.

4. Performance Testing

The Permittee shall conduct a NO_x emissions performance test on Unit IGT3, in accordance with 40 CFR 60.8 and the test methods and procedures in 40 CFR 60.335. The performance test shall be used to demonstrate compliance with the emission limit contained in III.B.1.a of Attachment H. [40 CFR 60.335]

C. Sulfur Dioxide

1. Emission Limitations/ Standards

a. The Permittee shall not burn in Unit IGT3, any fuel that contains total sulfur in excess of 0.8 percent by weight (8000 ppmw). [40 CFR 60.333(b)][PCC 17.12.190.B]

[Material Permit Condition]

b. The Permittee shall not allow the total combined emissions of SO_2 from Unit IGT3 to equal or exceed 40 tons per year, calculated as a 12-month rolling total. [PCC 17.12.190.B]

2. Monitoring, Recordkeeping and Reporting Requirements [PCC 17.12.180A.3, A.4 & A5]

a. The Permittee may elect not to monitor the total sulfur content of the gaseous fuel combusted in the turbine, if the gaseous fuel is demonstrated to meet the definition of natural gas in 40 CFR 60.331(u). The Permittee shall use one of the following sources of information to make the required demonstration: [40 CFR 60.334(h)(3)]

i. The gas quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the gaseous fuel, specifying that the maximum total sulfur content of the fuel is 20 grains / 100 scf or less; or

ii. Representative fuel sampling data which shows that the sulfur content of the gaseous fuel does not exceed 20 grains / 100 scf. At a minimum, the amount of fuel sampling data specified in section 2.3.1.1 or 2.3.2.4 of appendix D to 40 CFR Part 75 is required.

b. To demonstrate compliance with III.C.1.b of Attachment H, the Permittee shall comply with the continuous emission monitoring, recordkeeping, and reporting requirements in III.E.2 of Attachment H.

D. Carbon Monoxide

1. Emission Limitations/Standards

The Permittee shall not allow the total combined emissions of carbon monoxide (CO) from IGT3 to equal or exceed 100 tons per year, calculated as a 12-month rolling total. [PCC 17.12.190.B]
[Material Permit Condition]

2. Monitoring, Recordkeeping and Reporting Requirements [PCC 17.12.180.A.3, A.4 & A.5]

a. The Permittee shall install, calibrate, maintain and operate and quality-assure a Continuous Emission Monitoring System (CEMS) consisting of CO and O2 or CO2 monitors for measuring CO emissions and diluent from IGT3. [PCC 17.12.180.A.2]
[Material Permit Condition]

b. The Permittee shall install, calibrate, maintain and operate the in-line fuel flowmeter monitoring systems for determining the natural gas input rate to IGT3 for each operating hour according to the manufacturer's instructions. [PCC 17.12.180.A.2]
[Material Permit Condition]

c. To demonstrate compliance with the annual CO emission limit in III.D.1 of Attachment H, the Permittee shall comply with the CEMS monitoring, recordkeeping, and reporting requirements in Condition III.E.2 of Attachment H.

E. Continuous Emissions Monitoring Systems (CEMS) [40 CFR §60.13, PCC 17.12.050.H.3]

1. New Source Performance Standards for Continuous Emission Monitoring Systems

To demonstrate compliance with III.B.1.a of Attachment H the Permittee shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) and data acquisition handling system (DAHS) to calculate a four hour rolling average NOx emission rate.

a. The Permittee shall comply with the following requirements in the General Provisions of 40 CFR 60 for each CEMS unit installed:

i. The CEMS and DAHS monitoring and recording devices shall be installed and operational prior to conducting initial performance test. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device. [40 CFR 60.13 (b)]

ii. The Permittee shall automatically 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 a written procedure. The zero and span must, as a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in 40 CFR, Part 60, appendix B. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified. [40 CFR 60.13 (d)(1)]

iii. Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under V.B.4.a (ii), the CEMS shall be in continuous operation and shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period. [40 CFR 60.13 (e) & (e)(2)]

iv. The CEMS devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of 40 CFR 60 (III.E.1.b of Attachment H) shall be used. [40 CFR 60.13 (f)]

v. The Permittee shall reduce all data to 1-hour averages. 1-hour averages shall be computed from four or more data points equally spaced over each 1-hour period. Data recorded during periods of continuous system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant). All excess emissions shall be converted into units of the standard. After conversion into units of the standard, the data may be rounded to the same number of significant digits as used to specify the emission limit. [40 CFR 60.13 (h)]

vi. The Permittee shall meet the notification and recordkeeping requirements in II.B.1.d and II.B.5 of Attachment H.

b. The Permittee shall comply with the following requirements in the Performance Specifications of 40 CFR 60 Appendix B, for each CEMS unit installed:

i. The CEMS installation and measurement location specification shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.1.

ii. Pretest preparation shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.2.

iii. Calibration drift test procedure shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.3.

iv. Relative accuracy test procedure shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.4.

v. Reporting requirements shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 8.5.

vi. Analytical procedures shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 11.0.

vii. Calculation and data analysis shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 12.0.

viii. Method performance shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 13.0.

ix. Alternative Procedures shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 16.0.

x. References are located in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 17.0.

xi. Tables, Diagrams, Flowcharts, and Validation data necessary for NOx CEMS testing are located in 40 CFR Part 60, Appendix B, Specification 2, Sections 2 & 18.0.

xii. Specifications and test procedures for O_2 and CO_2 CEMS in Stationary Systems shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 3.

xiii. Specifications and Test Procedures for CO CEMS in Stationary Sources shall be in accordance with the methods and procedures in 40 CFR Part 60, Appendix B, Specification 4.

2. Monitoring, Recordkeeping, and Reporting Requirements for Annual NOx, SO_2, and CO Emission Limits [PCC 17.12.180.A.3, A.4 & A.5]

a. For the purpose of compliance demonstration with annual NOx, and CO emission limits, the Permittee shall utilize the NOx, CO, diluent CEMS on Unit IGT3 in conjunction with the Data Acquisition and Handling System (DAHS) and fuel flow rate monitoring systems. A default value for SO_2 concentration will be calculated using equation 3 below. The DAHS will calculate emissions of NOx, SO_2 and CO in pounds per hour (lb/hr), tons per month, and tons per year, calculated monthly as a 12-month rolling total. The Permittee shall use the procedures in Method 19 of 40 CFR 60 Appendix A as applicable to calculate NOx, and CO mass emission rates.

b. The Permittee shall calculate SO_2 mass emission rates for Unit IGT3 using Equation 3 and 3A below:

$ER = (2.0 / 7000) \times 10^6 \times (S_{total} / GCV)$ where: (Equation 3)

ER = Default SO2 emission rate for natural gas combustion, lb/mmBtu
S_{total} = Total sulfur content of the natural gas from a valid purchase agreement, tariff agreement, or sampling, gr/100 scf
GCV = Gross calorific value of the natural gas from a valid purchase agreement, tariff agreement, or sampling, Btu/100 scf
7,000 = Conversion of grains/100 scf to lb/100 scf
10^6 = Conversion factor (Btu/mmBtu)

SO_2 rate = ER x HI rate where: (Equation 3)

SO_2 rate = Hourly mass emission rate of SO_2, lb/hr
ER = SO_2 default emission rate of 0.06 lbs/MMBtu
HI rate = Hourly heat input rate, MMBtu/hr

c. A period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour, for NOx, CO, and diluent concentration or heat input rate.

d. During CEMS system downtime, the Permittee shall implement the missing data procedures for NOx and CO shown in 40 CFR Part 75 Subpart D – Missing Data Substitution Procedures.

e. Each calendar month during which the combined 12-month rolling total for the NOx, emission rate from Unit IGT3 exceeds 40 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with XI.A of Part A.

f. Each calendar month during which the combined 12-month rolling total for the SO_2, emission rate from Unit IGT3, exceeds 40 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with XI.A of Part A.

g. Each calendar month during which the combined 12-month rolling total for the CO emission rate from Unit IGT3, exceeds 100 tons shall constitute an exceedance. Exceedances shall be reported to the Control Officer in accordance with XI.A of Part A.

h. Each individual day and 12-month rolling total for NOx, SO_2, and CO emission rates in the reporting period shall be included in the semiannual compliance certification required by VII of Part A.

i. Quality Assurance Requirements for Natural Gas Fuel Flow meters

   i. Each transmitter or transducer shall be calibrated by equipment that has a current certificate of traceability to NIST standards at least once every four calendar quarters in which a unit operated on natural gas for 168 hours or more during each quarter but not less than once every three years. The Permittee shall check the calibration of each transmitter or transducer by comparing its readings to that of the NIST traceable equipment at least once at the following levels: the zero-level, and at least two other upscale levels (e.g., “mid” and “high”), such that the full range of transmitter or transducer readings corresponding to normal unit operation is represented.

   ii. The Permittee shall calculate the accuracy of each transmitter or transducer at each level tested, using the following equation:

$$ACC = \frac{|R - T|}{FS} \times 100 \qquad \text{where:}$$

ACC = Accuracy of the transmitter or transducer as a percentage of full-scale.
R = Reading of the NIST traceable reference value (in milliamperes, inches of water, psi, or degrees).
T = Reading of the transmitter or transducer being tested (in

milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

FS = Full-scale range of the transmitter or transducer being tested (in milliamperes, inches of water, psi, or degrees, consistent with the units of measure of the NIST traceable reference value).

iii. If each transmitter or transducer meets an accuracy of ± 1.0 percent of its full-scale range at each level tested, the fuel flow meter accuracy of 2.0 percent is considered to be met at all levels. If however, one or more of the transmitters or transducers does not meet an accuracy of ± 1.0 percent of full-scale at a particular level, then the Permittee may demonstrate that the fuel flow meter meets the total accuracy specification of 2.0 percent at that level by using one of the following alternative methods. If, at a particular level, the sum of the individual accuracies of the three transducers is less than or equal to 4.0 percent, the fuel flow meter accuracy specification of 2.0 percent is considered to be met for that level. Or, if at a particular level, the total fuel flow meter accuracy is 2.0 percent or less, when calculated in accordance with Part 1 of American Gas Association Report No. 3, General Equations and Uncertainty Guidelines, the flow meter accuracy requirement is considered to be met for that level.

iv. If during a transmitter or transducer accuracy test the flow meter accuracy specification of 2.0 percent is not met at any of the levels tested, the Permittee shall repair or replace the transmitter(s) or transducer(s) as necessary until the flow meter accuracy specification has been achieved at all levels. (Note that only transmitters or transducers which are repaired or replaced need to be re-tested; however, the re-testing is required at all three measurement levels to ensure that the flow meter accuracy specification is met at each level).

v. For orifice-, nozzles, and venturi type flow meters, the Permittee shall perform a primary element inspection for damage and corrosion at least once every 12 calendar quarters in which a unit operated on natural gas for 168 hours or more during each quarter but not less than once during the term of this permit. If damage and/or corrosion are found, the Permittee shall replace the flow meter or restore the damaged or corroded flow meter to “as new” condition.

vi. The Permittee shall log in ink, or in an electronic format the date that the calibration and inspection was conducted, the results of the calibration or inspection, and corrective action taken if needed.

Tucson Electric Power
Irvington Generating Station
Air Quality Permit # 1052

ATTACHMENT I: MERCURY STANDARD PROVISIONS

I. APPLICABILITY

This attachment shall only apply to the coal fired boiler identified as Unit I4 to which the ADEQ Consent Order (Docket #A-15-09) signed by ADEQ on February 17, 2009 applies. There are no mercury emission standards included in this attachment, only monitoring, recordkeeping, reporting and testing. Emission standards will be incorporated at a future date when EPA promulgates a Mercury standard or the mercury standard in A.A.C. R18-2-734 becomes applicable. A significant revision submittal will be required to incorporate the EPA or ADEQ mercury standards. The mercury standard in R18-2-734 shall not apply until December 31, 2016. **All the conditions in this Attachment are Locally Enforceable Conditions only.**

II. GENERAL PROVISIONS

The following standards apply to the maintenance, monitoring, recordkeeping and testing of the mercury monitoring systems associated with Unit I4 in accordance with the February 17, 2009 ADEQ Consent Order. These requirements are in addition to any applicable requirements in the General Provisions in Part A of this permit, unless Attachment I is more stringent.

A. Mailing Address

All requests, reports, applications, submittals, and other communications to the Administrator and Control Officer pursuant to 40 CFR Part 60 shall be submitted to the Control Officer at the following addresses: [PCC 17.12.180.A.5]

Air Program Manager
Pima County Department of Environmental Quality
33 North Stone Avenue, Suite 700.
Tucson, AZ 85701

III SPECIFIC CONDITIONS

A. Emission Limits & Standards

None applicable with this revision per ADEQ Consent Order #A-15-09, Section III.F.

B. Air Pollution Control Requirements [PCC 17.12.180.A.2]

1. The Permittee shall operate and maintain Unit I4, including associated air pollution control equipment and monitoring system, in a manner consistent with safety and good air pollution control practices for reduction of mercury emissions.

   Associated air pollution control equipment shall refer to the existing fabric filters (FF) for Unit I4, and good air pollution control practices shall mean the practices that conform to those prescribed in the Operations & Maintenance (O&M) Plan herein referred to as the CAM Plan described in IV.A.2 of Part B

C. Operational & Other Requirements [PCC 17.12.180.A.2]

1. The Permittee shall implement a control strategy that is designed to achieve either 0.0087 lbs/GWh or a 50 percent reduction of total mercury emissions (based on inlet mercury in the coal) from Unit I4 for the time period beginning on January 1, 2011, or 185 calendar days after the Control Officer issues the permit revision and will end on December 31, 2015. The emission rate or percent reduction stated above shall be based on Unit I4's annual coal use average. [ADEQ Consent Order #A-15-09, Section III.A.1.a]

2. The O&M Plan designed to achieve the reductions in III.C.1 above shall be implemented beginning January 1, 2011 or 185 calendar days after the Control Officer issues the permit revision and will end on December 31, 2015. [ADEQ Consent Order #A-15-09, Section III.A.3]

D. Monitoring, Recordkeeping and Reporting Requirements [PCC 17.12.180.A.3, A.4 & A.5]

Until such time as the Department amends the mercury monitoring, recordkeeping and reporting requirements of R18-2-734.D, or USEPA finalizes a federal mercury monitoring, recordkeeping, and reporting rule, whichever occurs first, the Permittee shall apply the following monitoring, recordkeeping and reporting methods for determining mercury emissions from Unit I4.

1. The Permittee shall perform stack testing for Unit I4 during the calendar year in each of the early mercury reduction years. The early mercury reduction year shall not begin until the later of January 1, 2011, or 185 calendar days after the Control Officer issues the permit revision and shall end on December 31, 2015.

2. The Permittee shall conduct the stack testing downstream of Unit I4 fabric filters while coal is being burned as the main fuel, using EPA Reference Method 29 or other equivalent testing methods approved by the Control Officer. Results of the tests shall be reduced as outlet mercury rate in lbs/mmBtu.

3. If Unit I4 is not operating coal as its main fuel, the stack test shall not be performed until such time as the unit is back operating with coal as its main fuel.

4. If necessary, the Permittee shall conduct coal mercury and heating value analysis at least once each month for each coal type to determine monthly inlet mercury in lbs/mmBtu. For purposes of this Attachment, "inlet mercury" means the average concentration of mercury in the coal burned in Unit I4, as determined by ASTM methods, EPA-approved methods or an alternative method approved by the Control Officer. Should the Permittee decide to utilize analysis of coal samples provided be the coal supplier, an official copy of the analysis from the coal supplier shall be maintained.

5. If necessary to report percent reduction of total mercury emissions, the Permittee shall determine and record for each calendar year Unit I4's annual percent reduction of mercury emissions, using the inlet and outlet mercury data (based on coal use) obtained from III.D.2 & III.D.4 of this Section. The calendar year average inlet and outlet mercury rate shall be derived based on Unit I4 total calendar year heat input in lbs/mmBtu.

6. The Permittee shall submit annual reports to the Control Officer that contain either the calendar year average outlet mercury rate as determined by III.D.2 of Attachment I, or the calendar year based annual percent reduction of mercury emissions as determined by III.D.5 of Attachment I above. The report shall be submitted by February 15th and shall contain the results for the

preceding year. The first such report shall be submitted by February 15, 2012 for the emitting year of 2011.

E. Application to Incorporate Post-2015 Applicable Standards [ADEQ Consent Order #A-15-09, Section III.A.5]

The Permittee shall submit to the Control Officer the application for a significant permit revision required by A.A.C. R18-2-734(F) by no later than January 1, 2014, and shall include the following elements in the application:

a. The State Mercury Standard and any amendments adopted by the Director to ensure that the State Mercury Standard is not incompatible with a MACT standard promulgated by EPA.

b. A control strategy for meeting the State Mercury Standard and any amendments adopted by the Director to ensure that the State Mercury Standard is not incompatible with a MACT standard promulgated by EPA.

c. A demonstration that the control strategy is designed to meet the State Mercury Standard and any amendments adopted by the Director to ensure that the State Mercury Standard is not incompatible with a MACT standard promulgated by EPA.

d. A proposal to comply with the State Mercury Standard by December 31, 2016, except as provided in A.A.C. R18-2-734(H), under the following conditions;

(1) For the purposes of applying the exception established in A.A.C. R18-2-734(H), each date specified in that provision shall be increased by three calendar years.

(2) The exception in A.A.C. R18-2-734(G) shall not apply.

ATTACHMENT J: NON-NSPS EMERGENCY GENERATORS

I. APPLICABILITY

This section applies to the Non-NSPS generators identified as such in the equipment list.

II. OPERATIONAL LIMITATION [PCC 17.12.180.A.2]

A. The Permittee shall not operate the **Non-NSPS** emergency generator(s) for more than 500 hours per year on a rolling twelve (12) month total basis.

B. The Permittee shall record the monthly operating hours and recalculate a rolling twelve (12) month total within 10 calendar days following the end of the month. All records shall be maintained for five years. Installation and maintaining of a non-resettable hour meter may be used to satisfy this requirement. [PCC 17.12.180.A.3 & 4]

III. OPACITY STANDARD [PCC 17.12.180.A]

A. The Permittee shall not cause, allow, or permit to be emitted into the atmosphere from any **Non-NSPS** stationary rotating machinery, smoke for any period greater than ten consecutive seconds which exceeds 40 percent opacity. Visible emissions when starting cold equipment shall be exempt from this requirement for the first ten minutes. [PCC 17.16.340.E]

B. The Permittee shall not cause or permit the effluent from a single emission point, multiple emission point, or a fugitive emissions source to have an average optical density equal to or greater than 60 percent when a cold diesel engine is started or when a diesel engine is accelerated under load as measured in accordance with EPA Method 9. [PCC 17.16.040]

C. The Permittee shall conduct a visible emissions check on the exhaust stack of each generator at least quarterly while the generator is operating. For the purposes of this permit, a visible emission check is verification that abnormal emissions are not present at the generator stack. The Permittee shall record the date and time of the check, the name of the person conducting the check, the results of the check, and the type of corrective action taken (if required). All records shall be maintained for five years.

D. When requested by the Control Officer, the Permittee shall perform EPA Method 9 visible emissions observations on the generator(s) to demonstrate compliance with the opacity standard.

IV. FUEL LIMITATION [PCC 17.12.180.A]

A. The Permittee shall burn only the specified fuel(s) allowed for each generator in the equipment list for this permit. The Permittee shall only fire fuel less than 0.90% by weight of sulfur. [PCC 17.12.190.B]
[Material Permit Condition]

B. In order to demonstrate compliance with the fuel limitation required in IV.A of this Attachment, the Permittee shall maintain records of fuel supplier specifications which verify the sulfur content of the fuel, piped and/or as delivered. All records shall be maintained for five years.

ATTACHMENT K: NSPS EMERGENCY GENERATORS

I. APPLICABILITY

This section applies to the NSPS generators identified as such in the equipment list. All standards are federally enforceable unless indicated otherwise.

II. OPERATIONAL LIMITATION [40 CFR 60.4211(e)] [PCC 17.12.190.B.2]

A. For the purpose of maintenance checks and readiness testing, the Permittee shall not operate the **NSPS** emergency generator(s) for more than 100 hours per year on a rolling twelve (12) month total basis. There is no time limit on the use of emergency stationary ICE in emergency situations.

B. The Permittee shall record the monthly operating hours and recalculate a rolling twelve (12) month total within 10 calendar days following the end of the month. All records shall be maintained for five years. Installation and maintenance of a run-hour meter that records the run hours for the generator shall satisfy this requirement. [PCC 17.12.180.A.3 & 4]

III. OPACITY STANDARD [PCC 17.12.180.A]
[Locally Enforceable Conditions]

A. The Permittee shall not cause or permit the effluent from a single emission point or multiple emission point to have an average optical density equal to or greater than 20 percent. Cold diesel engines are exempt for the first 10 minutes. [PCC 17.16.040]

B. The Permittee shall not cause or permit the effluent from a single emission point, multiple emission point, or a fugitive emissions source to have an average optical density equal to or greater than 60 percent when a cold diesel engine is started or when a diesel engine is accelerated under load as measured in accordance with EPA Method 9. [PCC 17.16.040]

D. The Permittee shall conduct a visible emissions check on the exhaust stack of each generator at least quarterly while the generator is operating. For the purposes of this permit, a visible emission check is verification that abnormal emissions are not present at the generator stack. The Permittee shall record the date and time of the check, the name of the person conducting the check, the results of the check, and the type of corrective action taken (if required). All records shall be maintained for five years.

E. When requested by the Control Officer, the Permittee shall perform EPA Method 9 visible emissions observations on the generator(s) to demonstrate compliance with the opacity standard.

IV. FUEL LIMITATION [PCC 17.12.180.A]

A. The Permittee shall burn only the specified fuel(s) allowed for each generator in the equipment list for this permit. The Permittee shall only fire fuel less than 0.90% by weight of sulfur. [PCC 17.12.190.B]
[Material Permit Condition]

B. In order to demonstrate compliance with the fuel limitation required in IV.A of this Attachment, the Permittee shall maintain records of fuel supplier specifications which verify the sulfur content of the fuel, piped and/or as delivered. All records shall be maintained for five years.

V. OPERATIONAL LIMITATIONS [PCC 17.12.180.A.2]

A. Emission Limitations [40 CFR 4205(b), 40 CFR 60.4202(a) & (2), 40 CFR 89.112(a)]

1. Certified Emission Limits

   a. New Compression Ignition Internal Combustion Engines (CI ICE) subject to this Attachment shall be certified by the manufacturer at or below the applicable emission standards and shall continue to meet them for the useful life of the engine.

   b. Applicable emission standards are identified in the table below:

Maximum Engine Power	Model Year	NMHC+ NOx (g/kW-hr)	CO (g/kW-hr)	PM (g/kW-hr)
605 ≤ HP <750	≥2007	4.0	3.5	0.20

   c. The Permittee must operate and maintain applicable units according to the manufacturer's written instructions or procedures developed by the Permittee that are approved by the engine manufacturer, over the entire life of the engine. [40 CFR 60.4206]

B. Fuel Requirements [40 CFR 60.4207]

1. Beginning October 1, 2007, stationary CI ICE subject to this Attachment that use diesel fuel must use diesel fuel that meets the following requirements on a per-gallon basis: [40 CFR 60.4207(a) & 80.510(a)]

   a. Sulfur content: 500 parts per million (ppm) maximum;

   b. Cetane index or aromatic content, as follows:

      i. A minimum cetane index of 40; or

      ii. A maximum aromatic content of 35 volume percent.

2. Beginning October 1, 2010, stationary CI ICE subject to this Attachment that use diesel fuel must use diesel fuel that meets the following requirements on a per-gallon basis: [40 CFR 60.4207(b) & 80.510(b)]

   a. Sulfur content: 15 ppm maximum;

   b. Cetane index or aromatic content, as follows:

      i. A minimum cetane index of 40; or

      ii. A maximum aromatic content of 35 volume percent.

3. With respect to pre-2011 model year stationary CI ICE subject to this Attachment, the Permittee may petition the **Administrator** for approval to use remaining non-compliant fuel that does not meet the fuel requirements of V.B.1 & 2 of this Attachment beyond the dates required for the purpose of using up existing fuel inventories. If approved, the petition will be valid for a period of up to 6 months. If additional time is needed, the Permittee shall be required to submit a new petition. [40 CFR 60.4207(c)]

C. Emergency Designation [40 CFR 60.4211(e)]

Emergency stationary ICE may be operated for the purpose of maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. Maintenance checks and readiness testing of such units is limited to 100 hours per year. There is no time limit on the use of emergency stationary ICE in emergency situations. The Permittee may petition the Control Officer for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if the Permittee maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency ICE beyond 100 hours per year. Any operation other than emergency operation, and maintenance and testing as permitted in this Attachment, is prohibited.

D. Compliance [40 CFR 60.4211]

1. The Permittee must operate and maintain the applicable stationary CI ICE and control device (if any) according to the manufacturer's written instructions or procedures developed by the Permittee that are approved by the engine manufacturer. In addition, the Permittee may only change those settings that are permitted by the manufacturer. The Permittee must also meet the requirements of 40 CFR part 89, as they apply to the Permittee. [40 CFR 60.4211(a)]

2. For 2007 model year and later stationary CI ICE subject to this Attachment, the Permittee shall comply with the emission standards by purchasing an engine certified to the emission standards V.A.1.b (40 CFR 60.4205(b)), for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's specifications. The Permittee shall show compliance with this permit condition by maintaining manufacturer purchase records that show compliance with the emission rates. [40 CFR 60.4211(c)] [PCC 17.12.180.A.4]

VI. Monitoring Requirements [40 CFR 60.4209(a)]

A. The Permittee shall install a non-resettable hour meter on each applicable stationary CI ICE prior to startup of each engine.

VII. Recordkeeping Requirements [PCC 17.12.180.A.4]

A. Diesel Fuel Recordkeeping

The Permittee shall maintain records of fuel supplier certifications that show and verify compliance with all the diesel fuel requirements in II.B of this attachment.

VIII. Testing Requirements [40 CFR 60.4212] [PCC 17.12.180.A.3.a]

Should the Permittee elect to or be required to conduct performance testing to demonstrate compliance with the applicable standards of this Attachment, the Permittee shall do so in accordance with 40 CFR 60.4212.

IX. Additional Requirements [40 CFR 60.4218 & 60.4214(b)]

The General Provisions of 40 CFR 60.1 though 19 apply to applicable sources as indicated in Table 8 of 40 CFR Subpart IIII except that the Permittee is not required to submit an initial notification.

X Facility Recordkeeping [PCC 17.12.180.A.4]

All records required by, or generated to verify compliance with this attachment shall be maintained for five years from the date of record.

APPENDIX D

Request and Approval of MATS Extension & Letter on Selection of Regional Haze Limits

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.azdeq.gov

Janice K. Brewer
Governor

Henry R. Darwin
Director

JANUARY 28, 2014

RECEIVED
FEB - 4 2014
BY:

cc Erik Bakken
Walter Yosin
Chuck Komadina

Tucson Electric Power
Irvington Generating Station
Attn: Conrad Spencer
88 East Broadway Blvd.
Tucson, AZ 85701

Re: Extension for Compliance with Mercury Air Toxics Standard (MATS), Irvington Generating Station, Permit No. 1052

Dear Mr. Spencer,

ADEQ is in receipt of your letter dated December 26, 2013, regarding the request for a one year extension for compliance with 40 CFR § 63, Subpart UUUUU – NESHAP: Coal and Oil Fired Electric Utility Steam Generating Units (MATS) for the Tucson Electric Power (TEP) Irvington Generating Station Unit I4. Based upon the issues complicating the potential installation of retrofit emissions technology, including:

1. The still pending BART determination by EPA, expected to be finalized June 2014, which will affect Unit I4. TEP cannot move forward with specific design requirements to meet MATS until BART design requirements are known; and
2. Increased time needed to procure vendors due to the likely reduced number of vendors available because of the competing coal-fired plants nationwide and TEP's inability to begin the procurement process until the BART determination has been finalized;

ADEQ hereby approves the request for a one year extension of compliance with the MATS, pursuant to 40 CFR § 63.9(c) and § 63.6(i), with a final compliance achievement date of April 16, 2016. The extension is contingent upon the submittal of a permit revision request to incorporate the conditions of the extension of compliance into the Title V permit; a compliance schedule indicating the dates by which each step towards compliance will be reached; and progress reports that indicate the status of each compliance step, submitted within 30 days of each step noted in the compliance schedule. If you have any questions, please feel free to contact me at (602) 771-2288.

Sincerely,

Eric C. Massey, Director
Air Quality Division

Please File in permit folder

Tucson Electric Power

88 East Broadway Blvd.
Tucson, AZ 85701-1720

RECEIVED BY
PIMA COUNTY

MAR 15 2016

DEPARTMENT OF
ENVIRONMENTAL QUALITY

Certified Mail
7013 2250 0000 8577 4810

March 14, 2016

Kathleen Johnson, Director
Enforcement Division (Mail Code ENF-2-1)
USEPA Region 9
75 Hawthorne Street
San Francisco, California 94105-3901

Subject: Selection of Regional Haze Emission Limits
Tucson Electric Power Company- H. Wilson Sundt Generating Station

Dear Director Johnson:

I am pleased to inform you that Tucson Electric Power Company ("TEP"), as part of its resource diversification strategy and commitment to providing safe, reliable and affordable power in an environmentally responsible manner, has ended the use of coal at the H. Wilson Sundt Generating Station ("Sundt") over a year ahead of schedule.

TEP owns and operates Sundt, located in Tucson, Arizona, under Title V Air Quality Permit No. 1052. Sundt Unit 4 is subject to the source-specific federal implementation plan for regional haze codified under 40 CFR §52.145(j). Pursuant to 40 CFR §52.145(j)(11)(i), the plan requires TEP's notification by March 31, 2017, of its selection to comply with either Best Available Retrofit Technology ("BART") or the better-than-BART alternative emission limits.

This letter is to notify you of TEP's decision to comply by no later than December 31, 2017 with the better-than-BART alternative emission limits set forth under 40 CFR §52.145(j)(4). In anticipation of meeting the better-than-BART alternative emission limits, TEP has taken the following steps: 1) In September of 2015, plant operators depleted all on-site coal stock during the plant's last coal-firing event and 2) As of January 29, 2016, TEP notified the Pima County Department of Environmental Quality that Unit 4 will only fire natural gas or natural gas in combination with landfill gas. TEP will utilize the remaining time prior to the December 31, 2017 deadline to ensure that Unit 4 can operate within all applicable emissions limits with an adequate compliance margin.

Should you have any questions, please contact me at (520) 918-8351.

Sincerely,

Erik Bakken, Senior Director, Transmission
& Environmental Services

cc: U. Nelson, PDEQ ✓ [illegible]
S. Porter, PDEQ
D. Jordan, EPA
C. McKaughan, EPA
M. Mansfield, TEP
C. Spencer, TEP