PINAL POWER, LLC - MARICOPA

1. Introduction

The permit pertains to a new wood-waste biomass energy plant, owned and operated by Pinal Power, LLC. The facility is located at 38743 West Cowtown Road, Maricopa, Arizona. The SIC Code is 4911.

The source is situated in an area that was classified as of January 26, 2011 as nonattainment for PM-2.5. The area at least currently remains classified as attainment for all pollutants other than PM-2.5.

However, notwithstanding the current attainment designation for PM-10, actual monitoring data in the vicinity of the proposed facility has violated the PM-10 standard for years. In October 2009 the EPA formally requested that the Governor of Arizona propose appropriate portions of Pinal County as a new nonattainment area for PM-10. In March of 2010, the Governor proposed that the location of this proposed source and surrounding areas be designated as nonattainment for PM-10. Although the EPA has not yet taken final action, it appears certain that this facility will imminently fall within the new PM-10 nonattainment area.

This proposed project will produce a nominal 30 MW of electrical power through the installation and operation of a biomass boiler. It will be fueled primarily by municipal green waste and agricultural wood waste. This project will consume approximately 260,000 bone dry tons (BDT) of wood waste annually. This boiler will also be capable of combusting wood at a maximum design heat input rate of 410[1] MM Btu/hr, although the permit limits allowable average heat input.

The project configuration includes a biomass boiler, and ash handling systems, and a steam turbine with a condensor and cooling tower for heat rejection.

Emissions from the boiler will be controlled by the use of the following:

- Selective non-catalytic reduction (SNCR) to control NO_X emissions.
- Good combustion practices to control CO and VOC emissions.
- Trona injection to control hydrogen chloride emissions.
- Electrostatic precipitators (ESP) and mechanical collector rotoclone to control PM.
- Supplier certifications, coupled with a site-specific fuel analysis plan, to manage biomass feedstock, and to specifically quantify and control sulfur and chlorine in that feedstock.

The facility will be subject to Title V requirements as there is a potential for allowable annual emissions of either NO_X or CO to reach 100 tons. As an electric generating station with the potential to generate more than 25 MWs, the facility will also be subject to the requirements of the Title IV Acid Rain Program.

1 V. Thompson e-mail, 5/31/2011.

The proposed project is a synthetic minor with respect to Prevention of Significant Deterioration (PSD), and therefore is not subject to Best Available Control Technology (BACT) requirements and for the purposes of demonstrating continuous "synthetic minor" status (annual emissions of NO_X, CO and PM_{10}/$PM_{2.5}$ are less than 250 tons per year), this permit requires that the boiler be equipped with a continuous emission monitoring system (CEMS) for both NO_X and CO. NO_X will be monitored in accordance with EPA's acid rain requirements, and the Permittee will be required to implement CO CEMS that also meets the Performance Specifications contained in 40 CFR 60 Appendix B. Annual emissions of PM_{10}, $SO_{2,}$ VOC and HAPs (HCl) will be calculated using non-instrumental test results along with fuel monitoring data.

The facility will use clean burning natural gas during startups, shutdowns and when required to provide supplemental fuel.[2] Pipeline quality natural gas will be supplied from two separate pipelines in the area with a sulfur concentration of less than 5 grains per 100 dry standard cubic feet based on FERC tariffs from each supplier.

A 400 KW diesel generator will be used for emergency purposes only. Since the generator is manufactured before 2006, 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, Subpart IIII is not applicable to the facility.

A complete list of equipment from which emissions are allowed by this permit is given in Section 11 of this permit.

2. Listing of Federally Enforceable Applicable Requirements *[Mandated by 40 CFR §70.5(c)(4)]* (Code §§3-1-060.B.2.d, 3-1-081.A.2, 3-1-081.A.8.a)

A. Those specific provisions of the Pinal-Gila Counties Air Quality Control District ("PGAQCD") Regulations, as adopted by the Pinal County Board of Supervisors on March 31, 1975, and approved by the Administrator as elements of the Arizona State Implementation Plan ("SIP") at 43 FR 50531, 50532 (11/15/78), and specifically the following rules:

7-3-1.1	Emission Standards - Particulates - Visible Emissions - General
7-3-1.2	Emission Standards - Particulate Emissions - Fugitive Dust
7-3-1.3	Emission Standards - Particulates - Open Burning
7-3-1.7.A	Particulate Emissions - Fuel Burning Equipment
7-3-1.7.C	Particulate Emissions - Fuel Burning Equipment
7-3-1.7.D	Particulate Emissions - Fuel Burning Equipment

2 Actually relying on natural gas as a supplemental fuel would trigger, on an on-going basis, the NSPS capacity factor reporting under section 7.D.1.c.

7-3-1.7.E Particulate Emissions - Fuel Burning Equipment

7-3-4.1 CO Emissions - Industrial

7-3-5.1 Fuel Burning Equipment (Nitrogen Oxide Emissions)[3]

B. Those specific provisions of the Pinal-Gila Counties Air Quality Control District Regulations, as last amended by the Pinal County Board of Supervisors on June 16, 1980, and approved by the Administrator as elements of the Arizona SIP at 47 FR 15579 (4/12/82), specifically, the following rules:

7-3-1.1 Visible Emissions; General

7-3-1.7.F Fuel Burning Equipment

C. The New Source Performance Standard General Provisions, 40 CFR Part 60, Subpart A [40 CFR §§60.1 - 60.19 (1998)]

D. NSPS Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, 40 CFR Part 60, Subpart Db [40 CFR §60.40b (3/13/00)].

E. The Acid Rain Program, 40 CFR Part 72 (1998) and related regulations, Sulfur Dioxide Allowance System, 40 CFR Part 73 (1998) and Continuous Emission Monitoring, 40 CFR Part 75 (1998).

F. CAA §§608 & 611 (11/15/90); 40 CFR Part 82, Subpart F - Recycling and Emissions Reduction (9/7/95); regulations pertaining to use and handling of ozone-depleting substances.

G. Asbestos NESHAP Compliance [40 CFR Part 61§§145, 148, 150. Subpart M].

H. Those specific provisions of the Pinal County Air Quality Control District Regulations, as last amended by the Pinal County Board of Supervisors on October 27, 2004, and approved by the Administrator as elements of the Arizona SIP at 75 FR 17307, specifically, the following rules:

4-2-040 Reasonable Precautions Standards

3. Compliance Certification

A. Compliance Plan ***[Mandated by 40 CFR §70.(5)(c)(8)]*** (Code §§3-1-081.C, 3-1-083.A.7)
Insofar as the Permittee has certified that it is currently in compliance, the compliance plan consists of continued adherence to the requirements of this permit.

B. Compliance Schedule ***[Mandated by 40 CFR §§ 70.5(c)(8), 70.6(c)(3)]*** (Code §§3-

3 The 0.20 lb/MMBtu limit on oxides of nitrogen is far less stringent than the NSPS Subpart Db limitations, so this limitation is not further addressed in the permit.

1-060.B.1, 3-1-083.A.7.c)

Insofar as the Permittee is currently in compliance, no compliance schedule to attain compliance is required.

4. Authority to Construct Federally Enforceable - [Code §§3-1-010, 3-1-040 (as amended 10/12/95) approved as a SIP Element at 61 FR 15717 (4/9/96)]

A. In General

Emissions from this facility, specifically the equipment described in "Equipment Schedule" section below, and the operating configuration as defined below and more fully described in the application for permit, fall subject to the enforceable limitations identified throughout this permit. Therefore, based on the regulations in effect upon the date of issuance of this permit and a finding that allowable emissions from the equipment described in the Equipment Schedule will neither cause nor contribute to a violation of any ambient air quality standard even without any additional limitations, this permit constitutes authority to construct and operate such equipment.

B. Preservation of the NAAQS; Equipment Authorized and Required [Minor NSR limitations pursuant to Code §3-1-010 *et seq.*, SIP approved at 61 FR 15717 (4/9/96)]

1. Equipment List

This permit authorizes the installation of the equipment listed in Section 11 of this permit, consisting of a biomass boiler with a maximum heat input capacity of 410 mm btu/hr., a fuel handling system, an ash handling system, a cooling tower and a backup generator.

2. Boiler CEMs

Permittee shall install, and operate, on the boiler stack:

a. A CEMS system for NO_x, capable of recording 1-hour average NOx emission rates during periods of start-up, shut-down and steady-state operation, and configured to meet the requirements of 40 CFR §60.48b.b and the prevailing Acid Rain requirements as specified under 40 CFR Part 75 Continuous Emission Monitoring, Subpart A, Section §75.2 (a), except as those requirements are supplemented by 40 CFR §60.48b.b.2, including a system to track NOx emissions on an hourly, daily, monthly and rolling-12-month-average basis.

b. A CEMS system for CO including during periods of start-up, shut-down and steady-state operation, and including a system to track CO emissions on a daily, monthly and rolling-12-month-average basis.

c. A COMs systems to monitor opacity, conforming to the requirements of 40 CFR §60.48b.a, capable of monitoring opacity during periods of start-up, shut-down and steady-state operation, and including a system to record opacity on a 15-second basis and to continuously track average opacity on a rolling 6-minute basis.

3. Boiler SNCR

Permittee shall incorporate a system for the reduction of NO_X, which shall consist of a system for the selective non-catalytic reduction of NO_X, including ammonia injection that will meet the “synthetic minor” cap of this permit.

4. Boiler EGR

Permittee shall install and operate an exhaust gas recirculation system, interlinked to the NOx and O2/CO2 CEMs in a manner to allow real-time management of exhaust concentrations of both NOx and CO.

5. Boiler Good Combustion Practice

Permittee shall install a system for the reduction of CO and VOC emission from the boiler, which shall consist of incorporating good combustion practices that will meet the “synthetic minor” caps of this permit.

6. Boiler Rotoclone

Permittee shall install, maintain and operate rotoclone dust collector on the exhaust of the boiler, including in that system a manometer or another similar device to measure the pressure drop across the rotoclone. Permittee shall operate the rotoclone at the manufacturer’s recommended pressure drop range until the first approved performance report. After such test, the rotoclone shall be operated at the pressure drop range recorded during the performance test.

7. Boiler ESP

Downstream of the rotoclone, Permittee shall install an electrostatic precipitator ("ESP") to further control particulate matter emissions from the biomass boiler exhaust. Permittee shall install, maintain, and operate a voltmeter to measure the secondary voltage across the electrostatic precipitator on a continuous basis and shall record the voltage output on at least an hourly basis. Permittee shall operate the ESP at the manufacturer’s recommended voltage until the first approved performance test report, after which time the ESP shall be operated at the voltage recorded during the performance test.

8. Fuel Logger - Natural Gas

Permittee shall install a system to continuously record or allow accurate determination of the mass quantity of natural gas burned in the boiler.

9. Fuel Logger - Biomass Feedstock

Permittee shall install a system to quantify and record on at least a daily basis the mass of biomass feedstock fuel burned in the boiler.

10. Working Surface Stabilization

Permittee shall install and maintain permanent dustproof paving in all areas that will be exposed to recurring truck or vehicle[4] traffic.

11. Solid Fuel Storage and Conveyance

Permittee shall store all solid fuel in a building or in storage piles. The fuel shall be delivered to the boiler via enclosed conveyors. Any fuel stored in storage piles shall be subject to the opacity limits of Section 5.C.

12. Ash Handling and Storage

Permittee shall collect ash generated from the rotoclone, ESP and boiler and transport the ash via enclosed conveyors to a silo equipped with a bag-house to control emissions from the unit.

13. Ash Loadout

The silo ash load-out station shall be equipped with a truck-coupling to minimize fugitive emissions during the load-out operation.

14. Cooling Tower

The cooling tower shall be equipped with:

a. Drift eliminators configured to limit cooling tower particulate matter emissions to limit PM-10 emissions to no more than 0.383 lbs/hr, and PM-2.5 emissions to no more than 0.23 lbs/hr;

b. A system to monitor and log liquid flow rates in the cooling tower.

15. Heat Input Limitation and Monitoring

To sustain the validity of the physical, operational and modeling application analysis which underlines the projected short-term ambient impacts associated with this facility, the Permittee shall not exceed a maximum average hourly heat input rate of 410 MM Btu/hr (HHV-dry basis) to the boiler, based on a daily average.[5]

C. Operational Limitations to Avoid PSD Applicability; Emission Caps *[Federally enforceable provision, pursuant to §3-1-084]*

4 Confirmend with V. Thompson, 6/3/11. dpg

5 See section 7.C.12.d for compliance.

1. Emission Caps

Operation of the facility, including the number of emission units operating along with the emergency generator operation, the duration of unit-specific operation, start-up and shut-down events, and the unit-specific loading, shall be limited in combination such that emissions, including the emissions generated during start-up and shutdown events, of any of CO, NO_X, VOC, $PM_{10}/PM_{2.5}$ and SO_2 from the facility shall not exceed a cap of 240 tons per 12-calendar-month period per pollutant.

2. Violations

Exceeding that operational limitation shall constitute a violation of this permit for each day that emissions of the offending pollutant were emitted from any part of the facility during:

i. The calendar month in which the cap was exceeded; and

ii. Any subsequent calendar month in which the cap continues to be exceeded.

3. Triggering PSD

Absent a permit revision authorizing such emissions, exceeding 250 tons of emissions of any specific pollutant listed above during a rolling 12-calendar-month period shall trigger PSD review.

4. Consequence of Triggering PSD Review *[Federally enforceable provision, pursuant to §3-1-084]*Code §3-3-250.H.

At such time that this facility becomes a major source or effects a major modification directly as a result of relaxation of the foregoing source-wide operational limitation and accompanying emission caps, then the requirements of Chapter 3, Article 3 of the Code (§3-3-200 *et seq.*) shall apply to the source or modification as though construction had not yet commenced on the source or modification.

5. [Reserved][6]

6. [Reserved][7]

D. Operational Limitations to Avoid CAA §112 MACT Applicability; Emission Caps *[Federally enforceable provision, pursuant to §3-1-084]*

6 Given that the permit requires NOx CEMs and that system should be able to verifiably track compliance with the PSD-synthetic minor limitations, no apparent reason exists to limit short-term heat input in order to avoid triggering PSD.

7 Annual hours of operation limitation deleted; CEMs for NOx and CO assure compliance with annual emission caps. Annual emissions are not germane to short term impacts, and the rolling limitation on short-term firing rate provides reasonable assurance of conformity to application-posited short-term ambient impacts.

1. HCl Emission Cap

To avoid triggering a major source designation based on emissions of HCl, Permittee shall limit HCl emissions, based on a 12-month-rolling sum, to no more than 8 tons or 80% of the major source threshold in any 12-month period.

2. Chlorine Content Logger

To track potential HCl emissions, Permittee shall implement a system to prospectively quantify on a weekly basis the chlorine content in the biomass feedstock.[8]

3. HCl Control System

a. To control HCl emissions, Permittee shall install and operate a Trona injection system configured to neutralize HCl in the boiler stack.

b. Permittee shall maintain the initial hourly Trona injection rate of 26 #/hr.[9] while the boiler is combusting biomass, and continue with that injection rate until such time as Permittee develops, submits, and obtains Control Officer approval of a test-derived Trona injection rate pursuant to section 6.C.7, expressed as an hourly pound-mass of Trona/hourly MMBtu (HHV-dry basis) of biomass fuel, adequate to assure on-going compliance with the HCl emission cap under this permit.

c. Once the empirical Trona injection rate has been determined, on a weekly basis Permittee shall adjust the Trona injection rate to correlate to the current chlorine content as monitored under section 7.C.10.

4. Trona Logging System

Permittee shall install and operate a meter capable of logging or recording the hourly injection rate of trona.

E. Control Requirements [Federally Enforceable Provision, pursuant to Code §3-1-084].

1. Permittee at all times operate in accordance with the manufacturer's specifications in order to minimize emissions of particulate matter, nitrogen oxides, carbon monoxide, and volatile organic compounds. Permittee may transcribe those manufacturer's specifications into standard operating procedures to be utilized by on-site staff.

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8 For compliance, see section 7.C.10.

9 Assumes a 0.02% chlorine content in biomass feedstock, and a required Trona/chlorine injection rate of 1/2:1 (mass basis) to achieve 95% control; 131.73 tpy feedstock x 0.02% = 52.7#/hr of Cl; that requires 26.3#/hr of Trona injection.

5. Emission Limitations [Mandated by 40 CFR §70.6(a)(1)] (Code §3-1-081.A.2)

A. Applicable Limitations (Code §3-1-082)

Where different standards or limitations apply under this permit, the most stringent combination shall prevail and be enforceable.

B. Allowable Emissions (Code § 3-1-081.A.2.)

Permittee is authorized to discharge or cause to discharge into the atmosphere those emissions of air contaminants as set forth in Sections 3, 4 and 5 of this permit. Unless exempted as an insignificant activity under Code §1-3-140.75a, as a categorical exemption under Code §3-1-040.C., or authorized by a separate permit or by a revision or operational change allowed under this permit or under Chapter 3, Article 2 of the Code, Permittee shall not commence construction, operate or make any modification to this source in a manner which will cause emissions of any regulated air pollutant in excess of the 5.5 lbs/day de minimis amount defined in Code §1-3-140.37.

C. Emission Limits

1. NSPS SO_2 Emission Limitation - Exemption Demonstration - NSPS Subpart Db [40 CFR §60.42b.k.2]

Permittee shall manage the sulfur content of biomass fuel feedstock, and the sulfur content of natural gas, to limit the aggregate weekly average potential SO_2 emission to a rate of less than 140 ng/J (0.32 lb/MM Btu) heat input.

2. Particulate Matter Limitation - NSPS Subpart Db

a. Emission Limitation [40 CFR §60.43b.(h)]

On and after the date on which the initial performance test is completed or is required to be completed under 40 CFR §60.8, whichever date comes first, Permittee shall not cause to be discharged to the atmosphere from the affected facility any gases that contain PM in excess of 13 ng/J (0.030 lb/MM Btu) heat input.

b. Opacity [40 CFR §§60.43b.(f) & (g)]

On and after the date on which the initial performance test is completed or is required to be completed under 40 CFR §60.8, whichever date comes first, Permittee shall not cause to be discharged to the atmosphere from the affected facility any gases that exhibit greater than 20 percent opacity (6-minute average), except one 6-minute period per hour of not more than 27 percent opacity. The PM and opacity standards apply at all times, except during periods of startup, shutdown or malfunction.

3. NO_X Emission Limitation - NSPS Subpart Db [40 CFR §60.44b.(d), (h) &

(I)]

On and after the date on which the initial performance test is completed or is required to be completed under 40 CFR §60.8, whichever date comes first, Permittee of an affected facility that simultaneously combusts natural gas with wood, shall not cause to be discharged to the atmosphere from the affected facility any gases that contain NO_X (expressed as NO_2) in excess of 130 ng/J (0.30 lb/MM Btu) heat input.[10] Compliance with the above emission limit shall be determined on a 30-day rolling average basis. This NO_X emission limit shall apply at all times including periods of startup, shutdown or malfunction.

4. Opacity Limitations for Outdoor Storage Piles

The opacity from any plume or effluent generated from solid fuel stored in outdoor storage piles shall not be greater than 10 percent as determined by EPA Reference 9 **AND** not greater than 20 percent as determined by EPA Reference Method 203C.

5. Ash Silo Baghouse Control

The ash silo baghouse shall achieve at least a 99% control efficiency, as determined by EPA Reference Method 5.

D. Operational Limitations (Code §3-1-084)

The Permittee shall not exceed a maximum aggregate average hourly heat input rate of 410 MM Btu/hr (HHV-dry basis) to the boiler, based on all biomass fuels, as determined under section 7.C.12.d.

E. Fuel-Burning Equipment - Particulate Emissions[11]

1. SIP Limitation ***[Currently federally enforceable pursuant to PGAQCD Reg. 7-3-1.7 (3/31/75) approved as a SIP element at 43 FR 50531 (11/15/78)]***

For equipment with a heat input capacity of greater than ten but less than 4,000 million Btu per hour, particulate emissions shall not exceed:

$E = 1.02X^{-.231}$, where E = allowable rate of emissions in lbs per million BTU heat input, and

X = maximum heat input capacity in million BTU per hour.

10 Permittee considered taking a 10% capacity factor limitation, principally to avoid tracking and reporting natural gas capacity factor data. However, 40 CFR §60.44b.d requires that any exemption from the NOx limit requires an enforceable permit limitation limiting natural gas combustion to a 10% capacity factor, which would implicitly require tracking and reporting natural gas capacity factor data anyway.

11 This particulate matter limitation is far less stringent than the NSPS Subpart Db limitations, so this limitation is not further addressed in the permit.

2. Current Code Limitation (§5-23-1010)

For equipment with a heat input capacity of less than 4,200 million Btu per hour, particulate emissions shall not exceed:

$E = 1.02Q^{0.769}$, where E = maximum emissions in lbs./hr.

Q = maximum heat input of all operating fuel burning units on a plant premises, in million BTU per hour.

F. Generally Applicable Opacity Limits

1. SIP Limitation ***[Currently federally enforceable pursuant to PGAQCD Reg. 7-3-1.1 (6/16/80) approved as a SIP element at 47 FR 15579 (4/12/82)]***

The opacity of any plume or effluent shall not be greater than 40 percent as determined by Reference Method 9 in the Arizona Testing Manual (ADEQ, 1992). Nothing in this limitation shall be interpreted to prevent the discharge or emission of uncontaminated aqueous steam, or uncombined water vapor, to the open air.

2. Locally Enforceable Limitation (Code §2-8-300)

The opacity of any plume or effluent from any point source not subject to a New Source Performance Standard adopted under Chapter 6 of the Code, and not subject to an opacity standard in Chapter 5 of the Code, shall not be greater than 20% as determined in Method 9 in 40 CFR Part 60, Appendix A. Affected facilities include the bottom ash handling, flyash handling, and ash storage and shipment.

3. Code Limitation Rotating Equipment Only (Code §5-23-1010)

Permittee shall limit the opacity of emissions from any stationary rotating machinery, such that opacity does not exceed 40% for longer than 10 consecutive seconds. Visible emissions when starting cold equipment shall be exempt from the requirement of this subparagraph for the first 10 minutes of operation.

G. Particulate Emissions - Control of Fugitive Dust ***[Currently federally enforceable pursuant to PGAQCD Reg. 7-3-1.2 (3/31/75) approved as a SIP element at 43 FR 50531 (11/15/78)]*** (Code §§2-8-300. and 4-2-040.)

1. Permittee shall not cause, suffer, allow or permit a building or its appurtenances or open area to be used, constructed, repaired, altered or demolished without taking reasonable precautions to prevent particulate matter from becoming airborne. Particulate emissions shall be kept to a minimum by such measures as wetting down, covering, landscaping, paving, treating or by other reasonable means.

2. Permittee shall not cause, suffer, allow or permit the repair, construction or

reconstruction of a roadway or alley without taking reasonable precautions to prevent particulate matter from becoming airborne dust and other particulates shall be kept to a minimum by employing temporary paving, dust palliatives, wetting down, detouring or by other reasonable means. Earth or other material shall be removed from paved streets onto which earth or other material has been transported by trucking or earth moving equipment, erosion by water or by other means.

H. Reasonable Precautions Rule ***[Currently federally enforceable pursuant to PCAQCD Reg. 4-2-040 (4/27/04) approved as a SIP element at 75 FR 17307]***

1. Permittee shall not cause, suffer, allow, or permit a building or its appurtenances, subdivision site, driveway, parking area, vacant lot or sales lot, or an urban or suburban open area to be constructed, used, altered, repaired, demolished, cleared, or leveled, or the earth to be moved or excavated, or fill dirt to be deposited, without taking reasonable precautions to effectively prevent fugitive dust from becoming airborne.

2. Permittee shall not cause, suffer, allow, or permit a vacant lot, or an urban or suburban open area, to be driven over or used by motor vehicles, such as but not limited to all-terrain vehicles, trucks, cars, cycles, bikes, or buggies, without taking reasonable precautions to effectively prevent fugitive dust from becoming airborne.

3. Permittee shall not disturb or remove soil or natural cover from any area without taking reasonable precautions to effectively prevent fugitive dust from becoming airborne.

4. Permittee shall not crush, screen, handle or convey materials or cause, suffer, allow or permit material to be stacked, piled or otherwise stored without taking reasonable precautions to effectively prevent fugitive dust from becoming airborne.

5. Stacking and reclaiming machinery utilized at storage piles shall be operated at all times with a minimum fall of material and in such a manner, or with the use of spray bars and wetting agents, as to prevent excessive amounts of particulate matter from becoming airborne. Other reasonable precautions shall be taken, as necessary, to effectively prevent fugitive dust from becoming airborne.

6. Permittee shall not cause, suffer, allow or permit transportation of materials likely to give rise to fugitive dust without taking reasonable precautions to prevent fugitive dust from becoming airborne. Earth and other material that is tracked out or transported by trucking and earth moving equipment on paved streets shall be removed by party or person responsible for such deposits.

I. Fuel Limitations (Code §3-1-084)

1. Fuels - Site Specific Fuel Analysis Plan (40 CFR §§60.42b.k.2 & 60.49k.r, Code §§3-1-084 & 3-3-250.A.1)

a. Permittee is allowed to burn only biomass feedstock and pipeline natural gas in the boiler.

b. Biomass feedstock includes the following acceptable materials, unless the materials also fall within the definition below of prohibited materials:

i. Untreated wood or plant products;
ii. Agricultural residue, including permanent crop trees, limbs, branches, roots and seasonal crop stocks;
iii. Forest residues, including trees, limbs, branches and roots;
iv. Untreated and unprocessed urban wood waste, including landscape prunings, removed trees;
v. Pallets, crates, and clean lumber remnants that have been saw cut or dried only.

c. Biomass feedstock does not include the following prohibited items:
i. Manure;
ii. Urban wood waste known to generate toxic smoke, namely oleanders;
iii. Processed wood products, wherein for purposes of this subparagraph, "processed" means any manufacturing or treating of wood products which results in the wood products absorbing, being coated with, or being combined with inorganic chemical constituents of any kind, or volatile organic compounds, or other organic compounds which are not derived from wood or plant compounds. Specifically prohibited items include particle board, fiberboard, plywood, railroad ties, utility poles, construction demolition waste, furniture waste, furniture (except unfinished wood furniture), wood veneers, painted, varnished or stained wood, or the like;
iv Organic products of animal origin, including manure;
v. Organic refuse such as food wastes or other domestic or commercial organic waste;
vi. Plastic or fabric materials;
vii. Fossil fuels, including coal, oil and petroleum products;
viii. Hazardous wastes as defined under 42 USC §6903 or any successor or amendatory statute or rule, provided that adsorbed or absorbed trace amounts of pesticides, herbicides, fungicides or rodenticides approved under FIFRA[12] resulting from standard agricultural or landscaping practices shall not solely cause biomass materials to be characterized as hazardous waste.

d. Biomass feedstock sulfur content shall be limited to that which will produce a maximum average SO_2 potential emission rate of 0.32 lbs./MM Btu, as determined according to section 7.B.1.

12 Federal Insecticide, Fungicide and Rodenticide Act, 7 USC §§163 et seq. (1996).

e. Sulfur content in natural gas shall not exceed 5 grains per 100 standard cubic feet (scf).

f. For compliance reporting and emission inventory purposes, Permittee shall quantify SO_2 emissions using the above-defined limiting values.

2. Biomass Fuel Supplier Qualifications (Code §3-1-081.A)

a. Contracted Purchases

Permittee may accept biomass fuel from suppliers who have signed and maintain a current contract agreeing to provide or deliver only biomass fuels conforming to the limitations regarding allowable and prohibited materials in sections 5.I.1.b and 5.I.1.c of this permit. A copy of the current the contract for each supplier must be kept on-site.

b. Direct Acquisitions

Permittee may acquire biomass feedstock materials from individual suppliers on the spot market, provided that Permittee shall then be directly responsible for assuring delivery of only biomass fuels conforming to the limitations regarding allowable and prohibited materials in sections 5.I.1.b and 5.I.1.c of this permit.

c. Segregation and Inspection of Source-specific Fuels

Biomass feedstock materials delivered to the facility shall be segregated into discrete piles that correspond to the individual supplier of that particular fuel type, and maintained in those piles for at least 3 days after receipt. Piles for large quantities may be managed on a LIFO basis, provided individual materials maintain a 10-day in-pile residence.

d. Permittee shall conduct visual inspections of fuel shipments for compliance with sections 5.I.1.b and 5.I.1.c of this permit, and shall reject any nonconforming materials. Records of these visual inspections shall be kept, including the name of the person that conducted the inspection, the date and time and if unacceptable materials were found. If unacceptable or prohibited materials are found, the record should also reflect the source of the materials and how the non-conforming materials were handled.

3. Emergency Generator Fuels (Codes §§3-1-081.G, 5-23-1010.F)

Permittee shall combust only low-sulfur, on-road diesel fuel in the emergency generator.

4. Other Fuels (Codes §§3-1-081.G, 5-23-1010.F)

Permittee shall not use used oil, used oil fuel, hazardous waste, and hazardous waste fuel (as defined in federal, state, or county codes and rules) in the steam generating units without first obtaining a separate permit or an appropriate permit revision.

J. General Maintenance Obligation - Plant Wide (Codes §§3-1-081.E., 8-1-030.A.3)

At all times, including periods of start-up, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate the permitted facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions.

K. Additional Applicable Limitations - Plant Wide

1. Sandblasting - Plant Wide (Code §5-4-160.)

Permittee shall use at least one of the following control measures during sandblasting operations:

a. Vacuum collection system.
b. Confined blasting.
c. Wet abrasive blasting.
d. Hydroblasting.
e. A control measure that is determined by the Control Officer to be equally effective to control particulate matter emissions.

2. Asbestos NESHAP Compliance ***[40 CFR Part 61, Subpart M]*** (Code §§7-1-030.A.8, 7-1-060)

Permittee shall comply with Code §§7-1-030.A.8 and 7-1-060 and 40 CFR Part 61, Subpart M, when conducting any renovation or demolition activities at the facility.

3. Stratospheric Ozone and Climate Protection ***[40 CFR Part 82 Subpart F]*** (Code §§1-3-140.15, 1-3-140.58.k)

The permittee shall comply with the applicable standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F, Recycling and Emissions Reduction.

4. Use of Paints

a. Architectural Coatings (Code §5-12-370)

Permittee shall not employ, apply, evaporate or dry any architectural coating, as defined in §5-12-370.C, for industrial or commercial purposes, material containing photochemically reactive solvent as defined in §5-9-280 or shall thin or dilute any architectural coating with a photochemically reactive solvent.

b. Other Spray Painting (Code §5-13-390)

Permittee shall conduct spray painting operations except architectural coatings in an enclosed area designed to contain not less than 96% by weight of the over spray. An enclosed area means a 3-sided structure with walls a minimum of 8 feet high.

c. Disposal (Codes §§5-12-370 and 5-13-390)

Permittee shall not, during any one day, dispose of a total of more than one and one-half gallons of any photochemically reactive solvent or of any material containing more than one and one-half gallons of any such photochemically reactive solvent by any means which will permit the evaporation of such solvent into the atmosphere.

5. Equipment Operation (Code §3-1-08.A.2)

a. The Permittee shall operate and maintain all equipment according to manufacturer's specifications.

b. The Permittee shall maintain a copy of the manufacturer's specifications for all equipment on site.

6. Cutback and Emulsified Asphalt (Code §5-16-670)

Except as exempted in §5-16-680, Permittee:

a. Shall not use or apply the following materials for paving, construction or maintenance:

i. Rapid cure cutback asphalt;

ii. Any cutback asphalt material, road oils or tar which contains more than 1.5% by volume VOCs which evaporate at 500°F or less using ASTM Test Method D-402-76 or more than 27% by volume total solvent in the asphalt binder.

iii. Any emulsified asphalt or emulsified tar containing more than 3% by volume VOCs which evaporate at 500°F or less using ASTM Test Method D-244-89.

b. Shall not store within Pinal County any emulsified or cutback asphalt product which contains more than 1.5% by volume solvent-VOC unless such material lot included a designation of solvent-VOC content on data sheet(s) expressed in percent solvent-VOC by volume.

L. Acid Rain Program Requirements - Biomass Boiler ***[40 CFR Parts 72, 73, 75 and 76]*** (Code §3-6-565)

1. Affected Units[13]

For purposes of the continuous emission monitoring and reporting requirements under the Acid Rain program, the biomass boiler constitutes an "affected unit."

2. The Acid Rain Phase II Permit application and Certificate of Representation signed by the Designated Representative shall constitute the basis of the Acid Rain Permit element of this permit.

3. The Permittee shall comply with the Acid Rain requirements listed in 40 CFR Parts 72, 73 and 75, and any additional requirements listed within this permit. At a minimum, compliance with 40 CFR Part 75 shall include installation and operation of monitoring equipment and/or maintenance of recordkeeping as required under 40 CFR §§75.10, 75.11, 75.12 and 75.13

4. When provisions or requirements of the regulations incorporated pursuant to Code §3-6-565 (Acid Rain Program) conflict with any of the other applicable requirements set forth in this permit, the regulations incorporated under §3-6-565 shall apply and take precedence.

5. No permit revision shall be required for increases in emissions that are authorized by allowances acquired pursuant to the Acid Rain Program, provided that such increases do not require a permit revision under any other applicable requirement. (Code §3-1-081.A.6.a)

6. No limit shall be placed on the number of allowances held by the source. The source may not, however, use allowances as a defense to be in non-compliance with any other applicable requirement. (Code §3-1-081.A.6.b)

7. Any such allowance shall be accounted for according to the procedures established in regulations promulgated under Part IV of the CAA, commonly known as CAA Title IV. (Code §3-1-081.A.6.c)

8. All of the following are prohibited: (Code §3-1-081.A.6.d.)

   a. Annual emissions of sulfur dioxide in excess of the number of allowances to emit sulfur dioxide held by the owners or operators of the unit or the designated representative of the owners or operators.

   b. Exceedances of applicable emission rates specified in this permit.

   c. The use of any allowance prior to the year for which it was allocated.

   d. Contravention of any other provision of this permit.

M. Emergency Risk Management Plan and Emergency Response Plan Requirements

13 None of the affected units at this facility are subject to a NOX emission limitation under 40 CFR Part 76.

At all times when the facility is subject to 40 CFR Part 68, the permittee shall comply with the planning requirements set forth in 40 CFR Part 68 with regard to the ammonia-handling and ammonia-storage at the facility, as well as any other process or facility affected under 40 CFR Part 68, including:

a. Submittal of a compliance schedule as required under 40 CFR Part 68, by the date required under 40 CFR §68.10(a); or

b. As part of the compliance certification submitted under 40 CFR §70.6(c)(5), a certification statement that the source is in compliance with all requirements of 40 CFR Part 68, including the registration and submission of a release management plan.

6. Compliance Demonstration - Testing *[Mandated by 40 CFR §70.6]* (Code §§3-1-060.b.2.d, 3-1-081.A.2, 3-1-083)

A. Fuel Testing

To enable verification of compliance with the various limitations and requirements under this permit, Permittee shall conduct weekly testing of the composition of biomass feedstock fuel, as follows:

1. Incoming Material Initial-sampling Protocol

i. Prior to startup, Permittee shall develop a sampling protocol for grab-sampling incoming biomass feedstock fuels in order to provide a statistically valid quantification of fuel-borne sulfur and chlorine. That protocol shall be submitted at least sixty days prior to startup, and shall be subject to approval by the Control Officer.

ii. Upon startup and thereafter, Permittee shall invoke that sampling protocol, coupled with the corresponding mass of material of that fuel type transferred to the primary biomass fuel reservoir, to conduct initial sampling and to further calculate an expected average mass fraction concentration of chlorine and sulfur in that primary fuel reservoir.

2. Weekly Compliance Sampling

On a weekly basis, Permittee shall obtain a weekly fuel sample by taking a "stopped belt, full-cut" sample[14] from the conveyor feeding the boiler.

3. Chlorine Testing [Code §3-1-084]

Permittee shall process a portion of that weekly compliance sample to determine and record average chlorine content using ASTM E776 or equivalent, and shall also record whether the test-derived chlorine content

14 See discussion of biomass sampling at www.advancedbiomass.com/2010/04/see-new-post-on-biomass-sampling/

differs from the expected concentration under section 6.A.1. To timely enable any required adjustment of the Trona injection rate under section 4.D.3, results of the chlorine content analysis shall be completed within 12 hours of the extraction of the sample under section 6.A.2.

4. Sulfur Testing [NSPS Subpart Db [40 CFR §60.42b.k.2]

On a cycle adequate to comply with the monitoring requirement of section 7.B.1, Permittee shall process a portion of that weekly compliance sample to determine and record average sulfur content using ASTM D4239 or equivalent, and shall also record whether the test-derived sulfur content differs from the expected concentration under section 6.A.1.

5. Heat Value Determination [NSPS Subpart Db [40 CFR §60.42b.k.2]

Permittee shall process a portion of that weekly compliance sample to determine and record the average heat content using ASTM E870-82 and E711-87 or equivalent.

6. Annual Heavy Metals Determination

As part of the initial weekly compliance test, and on an annual basis thereafter, Permittee shall quantify the mass fraction of lead, mercury and cadmium present in that sample.

B. Compliance With NSPS Subpart Db Performance Testing

1. SO_X NSPS Testing Requirements [40 CFR Part 60, Subpart Db, §60.45b.(j)]

To the extent the aggregate sulfur dioxide emissions, expressed as a function of heat content in units of ng./J as quantified under section 7.C.7, falls below the limiting value of section 5.I.1.d, this facility is exempt from the Subpart Db SO_x testing requirements.

2. PM NSPS Testing Requirements [40 CFR Part 60, Subpart Db, §60.46b.(d)]

a. To determine compliance with the PM emission limits and opacity limits under §60.43b of Subpart Db ("this part"), the owner or operator of an affected facility shall conduct an initial performance test as required under §60.8, and shall conduct subsequent performance tests as requested by the Administrator, using the following procedures and reference methods:

i. Method 3A or 3B of appendix A–2 of this part shall be used for gas analysis when applying Method 5 of appendix A–3 of this part or Method 17 of appendix A–6 of this part.

ii. Method 5, 5B, or 17 of appendix A of this part shall be used to measure the concentration of PM.

iii. Method 9 of appendix A of this part shall be used for determining the opacity of stack emissions.

3. NO_X NSPS Testing Requirements [40 CFR Part 60,Subpart Db §60.46b.(1), (4)]

To determine compliance with the emission limits for NO_X required under §5.C.3 of this permit, the owner or operator of an affected facility shall conduct the performance test as required under §60.8 using the continuous system for monitoring NO_X under §60.48(b) of Subpart Db.

a. For the initial compliance test, NO_X from the steam generating unit shall be monitored for 30 successive steam generating unit operating days and the 30-day average emission rate shall be used to determine compliance with the NO_X emission standards under §60.44b. The 30-day average emission rate shall be calculated as the average of all hourly emissions data recorded by the monitoring system during the 30-day test period.

b. Following the date on which the initial performance test is completed or required to be completed under §60.8, whichever date comes first, the owner or operator of an affected facility that has a heat input capacity of 73 MW (250 MMBtu/hr) or less and that combusts natural gas, distillate oil, gasified coal, or residual oil having a nitrogen content of 0.30 weight percent or less shall upon request determine compliance with the NO_X standards in §60.44b through the use of a 30-day performance test. During periods when performance tests are not requested, NO_X emissions data collected pursuant to §60.48b(g)(1) or §60.48b(g)(2) of Subpart Db shall be used to calculate a 30-day rolling average emission rate on a daily basis and shall be used to prepare excess emission reports, but shall not be used to determine compliance with the NO_X emission standards. A new 30-day rolling average emission rate shall be calculated each steam generating unit operating day as the average of all of the hourly NO_X emission data for the preceding 30 steam generating unit operating days.

C. NON-NSPS Performance Testing (Code §3-1-050)

1. Initial Performance Tests [Code §§3-1-160 & 3-1-170)

Within 60 days after the boiler and the affected units are subjected to these permit requirements but no later than 180 days after initial start-up of such unit and at such other times as may be required by the Control Officer, the owner or operator of such source shall conduct performance tests and shall furnish the Control Officer a written report of the results of the tests as provided below. These tests shall be performed at the maximum practical production rate. The continuous monitoring systems required by this permit shall be in place and operating prior to conducting the performance tests. Each performance test shall address:

a. Nitrogen oxides emissions, Ref. Part 60, App. A, Ref. Method 7E or 20; or timely completion of the NO_x NSPS testing required under §6.B.3.
b. Carbon monoxide emissions, Ref. Part 60, App. A, Ref. Method 10.
c. Particulate matter emissions[15] (filterable PM_{10} and $PM_{2.5}$), Ref. Part 60, App. A, Ref. Method 5 or 201A and (condensible PM_{10}) Method 202.
d. Sulfur dioxide emissions, Ref. Part 60, App. A, Ref. Method 6.
e. Volatile organic compound emissions, Ref. Part 60, App. A, Ref. Method 25a
f. Hydrogen Chloride (HCl) emissions, Ref. Part 60, App. A, Ref. Method 26
g. Opacity, Ref. Part 60, App. A, Ref. Method 9, 40 CFR §60.11.

2. PM Non-NSPS Testing Requirements

a. Boiler PM Testing

i. Permittee shall, during the initial and subsequent performance tests for particulate matter, conduct testing of the boiler for particulate matter using the testing methods listed in Section §6.C.1 of this permit, including determination of the PM_{10} and $PM_{2.5}$ control efficiency by the rotoclone/ESP.

ii. The initial tests shall be performed at the maximum production rate and utilizing the wood waste/fuel combination determined to have the highest HHV.

iii. During the rotoclone/ESP system test, Permittee shall record the pressure drop and secondary voltage that the rotoclone/ESP will be operated at. The pressure drop and voltage shall be submitted with the test report.

iv. The test protocol required to be submitted shall indicate the fuel specification and type of fuel that will be utilized for the test.

b. Cooling Tower Testing

In the alternative, Permittee shall test for particulate matter emissions from the cooling tower by either:

i. Conducting a performance test to directly, or through use of a tracer compound, quantify the PM_{10} emission rate from the cooling tower drift eliminators; or

ii. Conducting a performance test to classify and quantify the range of droplet sizes escaping from the cooling tower drift

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15 EPA has finalized the revisions to test method 201A to quantify emissions of PM2.5.

eliminators; or

iii Conducting a performance test to classify total drift loss using modified EPA Test Method 13A or EPA Test Method 306.

c. Baghouse Testing

During initial and subsequent testing, Permittee shall test for the capture efficiency of the ash silo baghouse using EPA Method 5.

3. Boiler Hydrogen Chloride Acid (HCl) Testing Requirements

i. Permittee shall conduct three separate initial performance tests to quantify uncontrolled hydrochloric acid emissions, emissions controlled with 50% of the default Trona injection rate specified in section 4.D.3, and emissions controlled with 100% of the default Trona injection rate specified in section 4.D.3.

ii. HCl emissions shall be quantified in accordance with the test methods listed in Section §6.C.1 of this permit.

iii. The HCl tests shall all be conducted while combusting biomass feedstock fuel with a known chlorine content determined under section 6.A.3.

iv. Based on the degree of HCl reduction achieved by the respective Trona injection rates, Permittee shall calculate a valid Trona injection rate, expressed in terms of pounds-of-Trona/MMBtu (HHV - dry basis) of biomass in order to comply with the HCl emission cap of section 4.D.1, and apply for a minor permit revision to accordingly revise the default Trona injection rate in section 4.D.3.

D. NSPS and Non - NSPS Performance Test Protocol & Subsequent Testing Requirements (Code §3-1-170)

1. Test Protocol

A test plan protocol for each test shall be submitted to the District at least thirty (30) days before the testing.

2. Performance Test Notices

Notice of any performance test required by this permit shall be submitted to the District at least thirty (30) days prior to running the test.

3. Test Reports

A copy of each test report shall be submitted to the District for approval within forty-five (45) days after the test. In addition to any other information required under this permit, test reports for all mandatory tests shall specifically define:

a. NO_X emission rates, defined as both as a function of heat input, and expressed in the same units as the NO_X emission limitations imposed in Section §5.C.3 of this permit.

b. SO2 emission rates, defined as both a function of heat input, and expressed in the same units as the SO2 emission limitations imposed in Section §5.C.1 of this permit.

4. Subsequent Testing

a. Particulate Matter

After initial performance test, Permittee shall conduct subsequent performance tests for particulate matter once a year by the anniversary date of the initial test.

b. Other Pollutants

After the initial performance test, Permittee shall conduct subsequent performance tests for SO_X, VOC and HCl acid once every two years by the anniversary date of the initial test.[16]

E. Non-NSPS General Opacity Testing

1. Opacity shall be determined using Reference Methods 9 and 203C, as applicable, in 40 CFR Part 60, Appendix A.

2. In addition to the opacity monitoring described in the following section of this permit, within 6 months of the start-up of this facility, and every 6 months after that, Permittee shall conduct a full opacity test performed by a certified opacity observer on the following emission points:

a. Biomass Fuel Handling System: Each transfer point;

b. Flyash handling system;

c. General Facility: all vents, exhausts and stacks.

3. To determine compliance, both Methods 9 and 203C shall be conducted on each emission unit described in subsections a. and b. above.

4. Method 9 opacity tests shall consist of at least 1 hour of data, averaged in blocks of consecutive 6-minute periods. The average opacity for each 6-minute period shall be recorded at the end of each period.

F. Acid Rain Compliance [Mandated by 40 CFR Parts 72 and 76]

16 NOx CEMs, backed by RATA testing, are required under §7.C.1.b and CO CEMs, backed by performance specification are required under §7.C.2.b.

For affected units, Permittee shall monitor SO_2, and NO_X emissions in accord with the requirements of 40 CFR Part 75. At a minimum, monitoring and corresponding records required under this subsection shall conform to the requirements of 40 CFR §§75.10, 75.11, 75.12 and 75.13.

7. Monitoring and Recordkeeping Requirements

A. Monitoring of Boiler Operations

To enable verification of compliance with the various limitations and requirements under this permit, Permittee shall quantify and record records of:

1. Hours of operation of the boiler;

2. Daily occurrence of boiler startup and shutdown events;

3. Daily quantity of natural gas fired in the boiler; and

4. Hourly mass of biomass feedstock fed to the boiler.

B. Emission Monitoring Subpart Db [40 CFR Part 60, §60.47b]

1. Emission Monitoring for Sulfur Dioxide [40 CFR Part 60, §60.47b.(f), §60.49b(r)(2)]

a. To the extent the aggregate sulfur dioxide emissions, expressed as a function of heat content in units of ng./J as quantified under section 7.C.7, falls below the limiting value of section 5.I.1.d, this facility is exempt from the Subpart Db SO_x monitoring requirements.
b. For the first 12 months of operation, Permittee shall, on a weekly basis, monitor, record and log sulfur content as a function of heat input.[17]
c. Following the first 12 months of operation, if the annual average sulfur content is less than 50% of the 0.32 lb/MMBtu threshold of section 5.C.1, Permittee may revert to monthly sulfur testing. If any subsequent quarterly average exceeds 75% of the 0.32 lb/MMBtu threshold, Permittee shall again implement weekly testing until the 12-month average again falls below the 50% threshold.

2. Emission Monitoring for Particulate Matter [40 CFR Part 60, §60.48b .(a)]

Permittee shall install, calibrate, maintain and operate the continuous opacity monitoring system (COMS) required under section 4.B.2.c for measuring opacity emissions discharged to the atmosphere and record the output of the system.

3. Emission Monitoring for Nitrogen Oxides [40 CFR Part 60, §60.48b.(b).(2)]

17 For compliance, see section 6.A.2, 6.A.4 and 6.A.5.

a. Permittee shall install, calibrate, maintain and operate the continuous emission monitoring system (CEMS) required under section 4.B.2.a to meet the ongoing requirements of 40 CFR Part 75, and shall utilize that CEMS to meet the requirements of this section, except that the owner or operator shall also meet the requirements of §60.49b. Data reported to meet the requirements of §60.49b shall not include data substituted using the missing data procedures in subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of Part 75.

b. The CEMS required under this section shall be operated and data recorded during all periods of operation of the affected facility except for CEMS breakdowns and repairs. Data is recorded during calibration checks, and zero and span adjustments.

c. The 1-hour average NO_X emission rates measured by the continuous NO_X monitor required by paragraph (b) of this section and required under §60.13(h) shall be expressed in ng/J or lb/MMBtu heat input and shall be used to calculate the average emission rates under §60.44b. The 1-hour averages shall be calculated using the data points required under §60.13(h)(2).

d. The procedures under §60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

C. Regular Emission Monitoring ***[Mandated by 40 CFR §70.6(a)(3)]***

1. Instrumental Emissions Monitoring - Oxides of Nitrogen [40 CFR 60.47 (a), (c) & (d), Code §3-3-260.]

a. Permittee shall install, calibrate, maintain and operate a continuous monitoring system to record daily emissions of nitrogen oxides from the boiler in accord with section 7.B.3.

b. Permittee shall conduct an initial NO_X CEMS evaluation and subsequent annual evaluations, in accord with the RATA requirements for NO_X CEMS, under 40 CFR Part 75, Appendix A.

c. Permittee shall monitor and record daily emissions of NO_X from the boiler, shall total and record those daily emissions on a calendar-month basis and shall maintain and record a rolling annual average of emissions, rolled on a calendar-month basis. In the event that CEMS data is unavailable due to monitoring equipment malfunction, Permittee may use Part 75 data substitution methodology to define the missing data.

2. Instrumental Emissions Monitoring - Carbon Monoxide [Code §3-3-260.G]

a. Permittee shall install, calibrate, maintain and operate a continuous emission monitoring system (CEMS) required under section 4.B.2.b to record daily emissions of carbon monoxide from the boiler. The monitoring equipment required under this permit subsection shall be installed and operated in accord with requirements of 40 CFR Part 60.

b. Permittee shall conduct an initial CO CEMS evaluation and subsequent annual evaluations, in accord with 40 CFR Part 60, Appendix B, Performance Specification 4 or 4A.

c. Permittee shall follow the quality assurance procedures in Procedure 1 of 40 CFR Part 60 Appendix F for the CO CEMS. The procedures include daily calibration drift and quarterly accuracy determinations.

d. Permittee shall obtain at least two data points per hour in order to calculate a valid 1-hour arithmetic average and complete at least one cycle of operation (sampling, analyzing and data recording) for each 15-minute period of operation.

e. Permittee shall obtain 1-hour averages for 75 percent of the operating hours per day for 90 percent of the operating days per calendar quarter.

f. If the Permittee does not obtain the minimum data required in paragraph “e” of this section, all valid data from the CO CEMS must be used in calculating emissions concentrations.

g. Permittee shall monitor and record daily emissions of CO from the boiler, shall total and record those daily emissions on a calendar-month basis and shall maintain and record a rolling annual average of emissions, rolled on a calendar-month basis. In the event that CEMS data is unavailable due to monitoring equipment malfunction, Permittee may use Part 75 data substitution methodology to define the missing data.

3. Quantifying Emissions Prior to CEMS Certification

For the time period between initial startup of the boiler and the initial evaluation / certification of the CEM systems, Permittee shall use fuel usage records and emissions factors determined from the initial performance tests to quantify NO_X and CO emissions.

4. After-the-fact Adjustment of Reported Emissions to Reflect CEMS Accuracy Deviations Shown by RATA Testing

The "reference period" shall consist of the time between successive RATA tests. If RATA testing establishes that actual emission rates, as shown by reference method testing, exceed the emission rates reported by the CEMS for the preceding reference period, then permittee shall apply a "bias adjustment factor" to the data acquisition system such that future reported emissions reflect the newly re-calibrated CEMS. In addition, the permittee shall recalculate the previously logged monthly emissions for each full month during the reference period by applying the same bias adjustment factor.

5. Parametric Emissions Monitoring Requirements - Natural Gas Sulfur Dioxide Emissions [Code §3-3-260.G]

As a surrogate measurement for monitoring emissions of sulfur dioxide from natural gas combusted, Permittee shall maintain daily records reflecting total fuel consumption. On a cycle adequate to comply with the emission limitations and semi-annual reporting requirements under this permit, Permittee shall utilize the SO_2 emission calculation methodology set forth in 40 CFR part 75, Appendix D §2.3, to calculate and report SO_2 emissions. Permittee shall determine fuel sulfur content by either:

a. Sampling the gaseous fuel daily when operating; or

b. Maintaining a contractual commitment with the pipe line gas supplier demonstrating that the gas has a total sulfur content of 5 grains per 100 standard cubic feet (scf) or less.

6. Parametric Emissions Monitoring Requirements - Aggregate Sulfur Dioxide Emissions [Code §3-3-260.G]

On a rolling 4-week-basis, rolled weekly, Permittee shall calculate and record the average aggregate SO_2 emissions as a function of total heat value combusted in the boiler during that preceding 4-week period, based on:

a. The heat value of the quantity of biomass feedstock fuel as determined by the daily biomass firing rate under section 7.A.4 and weekly test-derived heat content as determined under section 6.A.5;

b. The heat value of the quantity of natural gas combusted as determined under section 7.A.3;

c. The sulfur in the biomass feedstock fuel as determined under section 6.A.4; and

d. The sulfur in the natural gas combusted as determined under section 7.C.6.

7. Parametric Emissions Monitoring - Particulate Matter [Code §3-3-260.G.]

a. General Opacity Monitoring

i. On at least a monthly basis, Permittee shall conduct a visual opacity screen on all process emission points, conveyor transfer points and fugitive sources including storage piles, bulk material handling and ash handling during operations. Opacity screening shall be conducted during relevant process operations. The individual conducting the opacity screen need not be a certified opacity observer, and the screening need not conform to any EPA reference method.

ii. Permittee shall keep a record, signed by the observer, showing the date, time and results of the screening.

iii. If a screening identifies any visible emissions from the ash silo baghouse or the ash load-out operation, or any other emissions that may exceed the applicable opacity standard, a certified observer shall conduct a Method 9 and Method 203C, as applicable, observation of the emission point(s) of concern and shall provide a copy of the results to the District within 10 days of first observing the visible emissions.

iv. Permittee shall conduct full opacity tests every day after the initial one until emissions from that point or exhaust are brought down below the appropriate standard. Results of these reoccurring tests shall also be submitted to the District.

v. If any of the Method 9 or Method 203C results indicate that an exceedance of the opacity standard has occurred, it shall be reported in accordance with §7.G of this permit.

b. Aggregate PM10 and PM2.5 Emissions [Code §3-3-260.G]

On a monthly basis, Permittee shall calculate and record the aggregate PM10 and PM2.5 emissions from the facility, and shall maintain and record a rolling annual total of emissions, rolled on a calendar-month basis, based on:

i. Hourly rates resulted from stack testing required by this permit. Until such tests are performed, Permittee shall use the emission rates used in the permit application;

ii. Emission factor from AP-42 for fuel and ash handling emissions.

8. Parametric Emissions Monitoring - Volatile Organic Compounds [Code §3-3-260.G.]

1. As a surrogate measurement for monitoring emissions of VOC, Permittee shall maintain daily records of the type and quantity of fuel usage in the boiler as well as the quantity of power produced when combusting that fuel. VOC emissions shall be calculated on the basis of the fuel consumption data. Permittee may rely upon manufacturer's data or test results to calculate VOC emissions.

2. Aggregate VOC Emissions

Based on the daily records required above, Permittee shall calculate and record the aggregate VOC emissions from the facility, and shall maintain and record a rolling annual total of emissions, rolled on a calendar-month basis.

9. Instrumental and Parametric Emissions Monitoring - Hazardous Air Pollutant [Code §3-3-260.G]

a. As a surrogate measurement for monitoring emissions of HAPs, Permittee shall conduct weekly testing of fuel to measure the mass fraction of chlorine in the fuel, in accord with sections 6.A.2 and 6.A.3.

b. Permittee shall log hourly rates of trona injection.

c. Aggregate HCl Emissions

On a weekly basis Permittee shall calculate and record HCl emissions for the previous week, based on actual biomass throughput for the previous week determined under section 7.A.4, corresponding heat content determined under section 6.A.5, corresponding chlorine content determined for that week under section 6.A.5, and anticipated HCl reduction based on the injection rate fixed for that week under section 4.D.3 coupled with the reduction-efficiency algorithm derived under section 6.C.7.

10. Periodic Monitoring - Emergency Generator

a. Fuel Sulfur Content

As a surrogate measurement for quantifying the sulfur content in diesel fuel for the emergency fire pump, Permittee shall:

i. Maintain contractual commitment with each supplier that furnishes diesel fuel, showing the sulfur fuel content on receipts of all fuel shipments qualifies for on-highway diesel fuel and does not exceed the 500 ppmv sulfur content limitation <u>or</u>

ii. Maintain MSDS from each fuel supplier showing that all diesel fuel purchased complies with this permit <u>or</u>

iii. Determine the percent sulfur by ASTM Method D-129-91 (Test Method for Sulfur in Petroleum Products - General Bomb Method).

11. General Parametric Emission Monitoring Requirements [Code §3-3-260.G]

To provide a basis for the other aspects of parametric monitoring set forth below, Permittee shall maintain monthly operating logs for the following:

a. Hours of operation; by mode

Hours of operation of the boiler, defining periods of normal operation, start-up periods, warm-up periods, shut-down periods and any repairs with regard to the boiler.

b. Heat input; by mode

Fuel flow/heat input to the boiler, separately defining fuel flow/heat input during the various system operating modes, including during startups, warm-up periods, normal operations and during shutdown.

c. Natural gas purchased

Amount of natural gas purchased (in therms).

d. Daily biomass heat input

For each calendar day the facility operates, daily biomass heat input calculations, based on the mass of biomass fuel feedstock fed to the boiler as determined by the hourly biomass firing rates determined under section 7.A.4 and weekly test-derived heat content as determined under section 6.A.5.

e. Monthly total heat input

At the end of each month, Permittee shall calculate and record a twelve month rolling total of the total heat input of the boiler in MMBtu for the previous twelve months. The twelve month total shall be based on the MMBtu throughput calculated in the previous subsection.

f. Fuel quality assurance documentation

Permittee shall develop and maintain a log, which may be in digital form, documenting for each load received:

i. The supplier for contracted materials;
ii. The physical location of the source of materials acquired on the spot-market supplier;
iii. The date of the incoming visual inspection;
iv. Whether any prohibited materials were identified; and
v. How any prohibited materials identified were handled.

g. Rotoclone pressure drop records

On a daily basis during operations, Permittee shall observe and record the pressure drop across the rotoclone.

h. ESP voltage drop records

On a daily basis during operations, Permittee shall observe and record the secondary voltage at the ESP.

i. Diesel fuel deliveries

Permittee shall keep records of all diesel fuel deliveries.

j. Emergency generator operation

To verify compliance with the operational limitations on the diesel-driven emergency generator, Permittee shall maintain a log, reflecting hours of both emergency and non-emergency operation. The log shall further include a narrative explanation of the nature of any "emergency" that required emergency use of the generator.

D. NSPS Reporting and Recordkeeping Requirements

1. General [40 CFR Part 60, Subpart Db §60.49b.(a).(1) & (3) & (b)]

a. The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by §60.7. This notification shall include:

i. The design heat input capacity of the affected facility and identification of the fuels to be combusted in the affected facility;

ii. The annual capacity factor at which the owner or operator anticipates operating the facility based on all fuels fired and based on each individual fuel fired.

b. The owner or operator of each affected facility subject to the SO_2, PM, and/or NO_X emission limits under §§60.42b, 60.43b, and 60.44b shall submit to the Administrator the performance test data from the initial performance test and the performance evaluation of the CEMS using the applicable performance specifications in appendix B of this part. The owner or operator of each affected facility described in §60.44b(j) or §60.44b(k) shall submit to the Administrator the maximum heat input capacity data from the demonstration of the maximum heat input capacity of the affected facility.

c. The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted for normal power production operation during each day and calculate the monthly capacity factor individually for natural gas and wood (including biomass) for the reporting period. The annual capacity factor is determined on a 12-month rolling average basis with a new annual capacity factor calculated at the end of each calendar month.[18]

2. Opacity Recordkeeping [40 CFR Part 60, Subpart Db §60.49b.(f).(1) &(2)]

18 See the footnote to permit section 5.C.3 for an explanation of the need to track the capacity factors for all fuels.

For an affected facility subject to the opacity standard in §60.43b, the owner or operator shall maintain records of opacity. In addition, an owner or operator that elects to monitor emissions according to the requirements in §60.48b(a) shall maintain records according to the following requirements:

a. For each performance test conducted using Method 9 and Method 22 of appendix A–4 of this part, the owner or operator shall keep the following records:

i. Dates and time intervals of all opacity observation periods;

ii. Name, affiliation, and copy of current visible emission reading certification for each visible emission observer participating in the performance test; and

iii. Copies of all visible emission observer opacity field data sheets and:

iv. Documentation of any adjustments made and the time the adjustments were completed to the affected facility operation by the owner or operator to demonstrate compliance with the applicable monitoring requirements.

3. Nitrogen Oxides Recordkeeping [40 CFR Part 60, Subpart Db §60.49b.(g) & (h)]

a. The owner or operator of an affected facility subject to the NO_X standards under §60.44b shall maintain records of the following information for each unit operating day:

i. Calendar date;

ii. The average hourly NO_X emission rates (expressed as NO_2) (ng/J or lb/MMBtu heat input) measured or predicted;

iii. The 30-day average NO_X emission rates (ng/J or lb/MMBtu heat input) calculated at the end of each steam generating unit operating day from the measured or predicted hourly nitrogen oxide emission rates for the preceding 30 steam generating unit operating days;

iv. Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards under §60.44b, with the reasons for such excess emissions as well as a description of corrective actions taken;

v. Identification of the steam generating unit operating days for which pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken;

vi. Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data;

vii. Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and

viii. Results of daily CEMS drift tests and quarterly accuracy assessments as required under appendix F, Procedure 1 of this part.

b. The owner or operator of the affected facility is required to submit excess[19] emission reports for any excess emissions that occurred during the reporting period.

4. Sulfur Dioxides Recordkeeping [40 CFR Part 60, Subpart Db, §60.49b)]

Permittee shall:

a. Obtain and maintain at the affected facility fuel receipts from the natural gas fuel supplier that certify that gaseous fuel meets the definition of natural gas as defined in §60.41b and the applicable sulfur limit.

b. Maintain monthly records of the SO2 emission calculations required pertaining to Section 7.B.1.

5. NSPS Reporting [40 CFR Part 60, Subpart Db §60.49b.w]

Reports pursuant to Subpart Db shall be submitted for each 6 month period measured from the issue date of the permit, shall be submitted to the Control Officer and the Administrator, and shall be postmarked by the 30th day following the end of the reporting period.

E. General Recordkeeping ***[Mandated by 40 CFR §70.6(a)(3)]*** (Code §3-1-083)

1. Permittee shall maintain at the source a file of all measurements, including monitoring system, monitoring device, performance test measurements, all monitoring system performance evaluations, all monitoring system or monitoring device calibration checks, adjustments and maintenance performed on these systems or devices and all other information required pursuant to any federally enforceable provision of this permit, recorded in a permanent form suitable for inspection.

19 For particulate matter, excess emissions are defined as all 6-minute periods during which the average opacity exceeds the opacity standards listed in this permit. 40 CFR §60.49b.h.1. and .3. For NOX, excess emissions are defined as any calculated 30-day rolling average NOX emission rate, that exceeds the applicable emission limits. 60 CFR §40.49.b.h.4.

2. Permittee shall record the following in a permanent logbook, which may be in written or digital form, for inclusion in the semi-annual report:

   a. Monthly emissions of nitrogen oxides, carbon monoxide, particulate matter (PM_{10} and $PM_{2.5}$), volatile organic compounds, hazardous air pollutants and sulfur dioxide,

   b. Total natural gas burned;

   c. Boiler run times;

   d. The number of start-up and shut-down cycles for the unit;

   e. Any malfunction in the operation of the permitted facility or any air pollution control equipment;

   f. Maintain records of all the diesel shipments received for the emergency generator along with the sulfur content in each diesel shipment and;

   g. Maintain operational hours of the emergency generator.

   h. Vendor-provided copy of the Federal Energy Regulatory (FERC) approved tariff agreement that contains the lower heating value of the pipeline quality natural gas.

3. Recordkeeping of Periodic Facility-Wide Activities (§3-1-081.A.3.b)

   Each time an abrasive blasting or spray painting project is conducted, Permittee shall keep records of the following:

   a. Date the project was conducted;

   b. Duration of the project;

   c. Type of control measures employed;

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

4. All information required pursuant to any federally enforceable provision of this permit, recorded in a permanent form suitable for inspection.

F. Semi-Annual Compliance Reporting ***[Mandated by 40 CFR §§70.6(a)(3) and 70.6(c)(4)]*** (Code §3-1-083.A)

In order to demonstrate compliance with the provisions of this permit, the Permittee shall submit a semi-annual report containing the information required to be recorded pursuant to this permit. The report shall be submitted to the District within 30 days after the end of each calendar half.

G. Regular Compliance/Compliance Progress Certification ***[Mandated by 40 CFR §§70.5(c)(8), 70.5(c)(9), 70.6(c)(4), 70.6(c)(5)]***

Permittee shall annually submit a certification of compliance with the provisions of this permit to the Control Officer, and also to the Administrator of the US EPA. The certification shall:

1. Be signed by a responsible official, namely the president, secretary, treasurer or vice-president of the corporation, the director of fossil generation, the plant manager, or such other person as may be approved by the Control Officer as an administrative amendment to this permit;

2. Identify each term or condition of the permit that is the basis of the certification;

3. Verify the compliance status with respect to each such term or condition;

4. Verify whether compliance with respect to each such term or condition has been continuous or intermittent;

5. Identify the permit provision, or other compliance mechanism upon which the certification is based; and

6. Be postmarked within thirty (30) days of the start of each calendar year.

H. Deviations from Permit Requirements (Code §3-1-81.A.5.b.)

Permittee shall report any deviation from the requirements of this permit along with the probable cause for such deviation, and any corrective actions or preventative measures taken to the District within ten days of the deviation unless earlier notification is required by the provisions of this permit.

8. Other Reporting Obligations

A. Supplemental Upset Reports ***[Mandated by 40 CFR §§70.6(a)(3)(iii)(B), 70.6(g)]***

Permittee shall report any deviation from the requirements of this permit along with the probable cause for such deviation, and any corrective actions or preventative measures taken to the District within fifteen days of the deviation unless earlier notification is required by the provisions of this permit.

B. Reconstruction Reporting ***[40 CFR Part 60, Subpart A, Code §6-1-030.1 and a delegation from the EPA Administrator dated 2/24/93]***

If the Permittee proposes to replace components of any of the boiler, such that the capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new unit, the Permittee shall notify the District of the proposed replacements. The notice shall be postmarked 60 days (or as soon as practicable) before construction is commenced, and must include the information required under 40 CFR §60.15(d) (1993).

C. NSPS Notification ***[40 CFR Part 60, Subpart A]***

Permittee shall provide notifications required by 40 CFR Part 60, Subpart A, pertaining to installation of, modification of, or a change in the method of operation of NSPS-affected units in a manner that will cause an increase in emissions of a regulated pollutant.

9. Fee Payment ***[Mandated by 40 CFR §§70.6(a)(7), 70.9]*** (Code §3-1-081.A.9)

As an essential term of this permit, an annual permit fee shall be assessed by the District and paid by Permittee in accord with the provisions of Code Chapter 3, Article 7 generally, and Code §3-1-081.A.9. specifically. The annual permit fee shall be due on or before the anniversary date of the issuance of an individual permit, or formal grant of approval to operate under a general permit. The District will notify the Permittee of the amount to be due, as well as the specific date on which the fee is due.

10. General Conditions

A. Term ***[Mandated by 40 CFR §70.6(a)(2)]*** (Code §3-1-089)

This permit shall have a term of five (5) years, measured from the date of issuance.

B. Basic Obligation ***[Mandated by 40 CFR §§70.4(b)(15), 70.6(a)(6(I), 70.6(a)(6)(ii), 70.7.b]*** (Code §3-1-081.)

1. The owner or operator ("Permittee") of the facilities shall operate them in compliance with all conditions of this permit, the Pinal County Air Quality Control District ("the District") Code of Regulations ("Code"), and consistent with all State and Federal laws, statutes, and codes relating to air quality that apply to these facilities. Any permit noncompliance is grounds for enforcement action; for a permit termination, revocation and reissuance, or revision; or for denial of a permit renewal application and may additionally constitute a violation of the Clean Air Act (1990).

2. All equipment, facilities, and systems used to achieve compliance with the terms and
conditions of this permit shall at all times be maintained and operated in good working order.

3. 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.

C. Duty to Supplement Application ***[Mandated by 40 CFR §§70.5(b), 70.6(a)(6)(v)]*** (Code §3-1-081.A.8.e.)

Even after the issuance of this permit, a Permittee, who as an applicant who failed to include all relevant facts, or who submitted incorrect information in an application, shall, upon becoming aware of such failure or incorrect submittal, promptly submit a supplement to the application, correcting such failure or incorrect submittal. In addition, Permittee shall furnish to the District within thirty days any information that the Control Officer may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or to determine compliance with this permit and/or the Code.

D. Right to Enter ***[Mandated by 40 CFR §70.6(c)(2)]*** (Code §§ 3-1-083.A.6, 3-1-132)

Authorized representatives of the District shall, upon presentation of proper credentials, be allowed:

1. to enter upon the premises where the source is located or in which any records are required to be kept under the terms and conditions of this permit;

2. to inspect any equipment, operation, or method required in this permit;

3. to sample emissions from the source.

4. to have access to and copy, at reasonable times, any records that are required to be kept under the terms of this permit; and

5. to record any inspection by use of written, electronic, magnetic and photographic media.

E. Transfer of Ownership ***[Mandated by 40 CFR §70.7(d)(4)]*** (Code §3-1-090)

This permit may be transferred from one person to another by notifying the District at least 30 days in advance of the transfer. The notice shall contain all the information and items required by Code § 3-1-090. The transfer may take place if not denied by the District within 10 days of the receipt of the transfer notification.

F. Posting of Permit (Code §3-1-100)

Permittee shall firmly affix the permit, an approved facsimile of the permit, or other approved identification bearing the permit number, upon such building, structure, facility or installation for which the permit was issued. In the event that such building, structure, facility or installation is so constructed or operated that the permit cannot be so placed, the permit shall be mounted so as to be clearly visible in an accessible place within a reasonable distance of the equipment or maintained readily available at all times on the operating premises.

G. Permit Revocation for Cause ***[Mandated by 40 CFR §70.6(a)(6)(iii)]*** (Code §3-1-140)

The Director of the District ("Director") may issue a notice of intent to revoke this permit for cause pursuant to Code §3-1-140, which cause shall include occurrence of any of the following:

1. The Director has reasonable cause to believe that the permit was obtained by fraud or material misrepresentation;

2. Permittee failed to disclose a material fact required by the permit application form or a regulation applicable to the permit;

3. The terms and conditions of the permit have been or are being violated.

H. Application Certification ***[Mandated by 40 CFR §70.5)(d)]*** (Code §§ 3-1-050. & 3-1-070.)

All representations with regard to construction plans, operating parameters, and operational procedures in the application for the permit are conditions upon which this permit is issued. Except as provided in Code §3-2-180, any variance from such representation if the change will cause a change in the method of control of emissions, the emission of any new regulated air pollutant in excess of the 5.5 pound-per-day *de minimis* amount defined in Code §1-3-140.37, or will result in an increase in the discharge of regulated air pollutants will be considered a violation of this permit unless the Permittee first applies for a permit, permit revision, or permit amendment, or provides advance notification of the change to the extent required by Code Chapter 3, Article 2.

I. Permit Expiration and Renewal ***[Mandated by 40 CFR §§70.5(a)(1)(iii), 70.7.(c)]*** (Code §3-1-050.C.2)

Expiration of this permit will terminate the facility's right to operate unless either a timely application for renewal has been submitted in accordance with §§3-1-050, 3-1-055 and 3-1-060, or a substitute application for a general permit under §3-5-490. For Class I permit renewals, a timely application is one that is submitted at least 6 months, but not greater than 18 months prior to the date of the permit expiration. For Class II or Class III permit renewals, a timely application is one that is submitted at least 3 months, but not greater than 12 months prior to the date of permit expiration.

J. Severability ***[Mandated by 40 CFR §70.6(a)(5)]*** (Code §3-1-081.A.7)

Pursuant to Code § 3-1-081.A.7., the provisions of this permit are severable, and if any provision of this permit is held invalid the remainder of this permit shall not be affected thereby.

K. Permit Shield ***[Mandated by 40 CFR §70.6(f)]*** (Code § 3-1-102.)

1. Generally

Subject to the following schedule of exclusions, compliance with the terms of this permit shall be deemed compliance with any applicable requirement identified in §2 of this permit. The permit-shield exclusions include:

a. PGCAQCD Rule §7-3-1.3 Open Burning;

b. PGCAQCD Rule §7-3-4.1 Industrial - Carbon Monoxide Emissions.

c. Items listed in Section 10 of this permit as not being federally enforceable.

2. Additional Inclusions Under the Permit Shield

The permit shield also extends to the following provisions of the code, due to a finding by the Control Officer of non-applicability:

a. Code §§5-22-950, 5-22-960 & 5-22-970, all dealing with Fossil Fuel-Fired Steam Generators.

L. Permit Revisions ***[Mandated by 40 CFR §70.7(d), 70.7(e)]*** (Code Chapter 3, Article 2, specifically Code §3-1-081.A.8.c)

1. This 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.

2. 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.

3. Permit amendments, permit revisions, and changes made without a permit revision shall conform to the requirements in Article 2, Chapter 3, of the Code.

4. Should this source become subject to a standard promulgated by the Administrator pursuant to CAA §112(d), then 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. (Code §3-1-050.C.5)

5. Revision to Permit Provisions Designated as Federally Enforceable Pursuant to Code §3-1-084 ***[Federally enforceable provision, pursuant to Code §3-1-084 (8/11/94)]***

As an express condition of preserving the federal enforceability of any provision of this permit designated "federally enforceable" pursuant to Code §3-1-084, Permittee shall not make any facility allowed change that would contravene such provision, until thirty (30) days after the Permittee has previously furnished notice of the proposed change to the District and to the Administrator, to thereby allow the Administrator opportunity to comment upon the continued "federal enforceability" of the subject provision after the proposed change.

M. Permit Re-opening ***[Mandated by 40 CFR §§70.6(a)(6)(iii), 70.7(f), 70.7(g)]*** (Code §3-1-087.)

1. This permit shall be reopened if:

a. Additional applicable requirements under the Clean Air Act (1990) become applicable to this source, and on that date, this permit has a remaining term of three or more years. Provided, that no such reopening under this subparagraph is required if the effective date of the newly applicable requirement is later than the date on which this permit is due to expire, unless the original permit or any of its terms and conditions has been extended pursuant to Code §3-1-089.C.

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

c. The Control Officer determines that it needs to be revised or revoked to assure compliance with the applicable requirements; or

d. The EPA Administrator finds that cause exists to terminate, modify, or revoke and reissue this permit.

2. If this permit must be reopened or revised, the District will notify the permittee in accord with Code §3-1-087.A.3.

N. Record Retention ***[Mandated by 40 CFR §70.6(a)(3)(ii)(B)]*** (Code §3-1-083.A.2.b) Permittee shall retain for a period of five (5) years all documents required under this permit, including reports, monitoring data, support information, calibration and maintenance records, and all original recordings or physical records of required continuous monitoring instrumentation.

O. Scope of License Conferred ***[Mandated by 40 CFR §70.6(a)(6)(iv)]*** (Code §3-1-081.A.8.d)

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

P. Excess Emission Reports; Emergency Provision ***[Mandated by 40 CFR §70.6(g)]*** (Code §3-1-081.E, Code §8-1-030)

1. To the extent Permittee may wish to offer a showing in mitigation of any potential penalty, underlying upset events resulting in excess emissions shall reported as follows:

a. The permittee shall report to the Control Officer any emissions in excess of the limits established by this permit. Such report shall be in two parts:

i. Notifications by telephone or facsimile within 24 hours or the next business day, whichever is later, of the time when the owner or operator first learned of the occurrence of excess emissions, including all available information required under subparagraph b. below.

ii. Detailed written notification within 3 working days of the initial occurrence containing the information required under subparagraph b. below.

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

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

ii. The magnitude of the excess emissions expressed in the units of the applicable limitation.

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

iv. The identity of the equipment from which the excess emissions occurred.

v. The nature and cause of such emissions.

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

vii. The steps that were or are being taken to limit the excess emissions. To the extent this permit defines procedures governing operations during periods of start-up or malfunction, the report shall contain a list of steps taken to comply with this permit.

viii. To the extent excess emissions are continuous or recurring, the initial notification shall include an estimate of the time the excess emissions will continue. Continued excess emissions beyond the estimated date will require an additional notification.

2. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation 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 emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of preventative maintenance, careless or improper operation, or operator error.

3. An emergency constitutes an affirmative defense to an action brought for noncompliance with such technology-based emission limitations if the conditions of the following subparagraph are met.

4. 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(s) of the emergency;

b. The permitted facility was at the time being properly operated;

c. During the period of 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 or hand delivery within 2 working days of the time when emissions limitations were exceeded due to emergency. The notice shall contain a description of the emergency, any steps taken to mitigate emissions, and corrective action taken.

Q. Emission Inventory (Code §3-1-103)

Permittee shall annually prepare and submit an emission inventory of actual emissions within thirty days of the start of each calendar year. In order of preference, the inventory shall be based on:

1. CEMs data where available;

2. Mass balance analysis based on fuel testing for sulfur;

3. SO_2 quantification conventions allowed under 40 CFR Part 75, Appendix D;

4. Parametric monitoring of fuel or other throughput parameters, coupled with AP-42 emission factors, based on the latest edition and supplement for AP-42;

5. Parametric monitoring of fuel or other throughput parameters, coupled with performance test data for the emission unit in question;

6. Other rational analysis.

11. Equipment Schedule ***[Mandated by 40 CFR §70.5(c)(3)(iii)]*** (Code §3-1-040.A)

Equipment for which emissions are allowed by this permit are as follows:

A. McBurney biomass boiler, 410 MMBtu/hr, 2010

B. 2 - 62.5 MM btu/hr natural-gas-fired burners

C. Fuel Handling operations (including fuel receiving, handling, storing and processing)

D. Fly ash handling operations (including bottom ash handling, storage, and shipment)

E. Cooling tower, 46,262 gpm capacity, equipped with drift eliminators

F. A 400 KW emergency diesel generator, manufactured prior to 2006.

12. Insignificant Activities]Mandated by 40 CFR §70.5.) [Code §3-1-050.E]

Permittee has disclosed the following insignificant activities in the permit application:

A. Short term maintenance activities including but not limited to painting etc.

B. Operation of plant water, wastewater and other water systems.

C. Emissions from testing and sampling.

D. Emissions from oil systems and tanks.

E. Storage of chemicals and fuels.

F. Operation of emergency and standby equipment rated at less than 325 brake horsepower and used less than 72 hours per year.

Appendix A

Semi-annual Report

Permit V20644.000

Abstract

This constitutes an outline of semi-annual report regarding required monitoring, documenting emissions during the subject reporting period. This constitutes a guide only, and is not meant to in any way absolve the permittee of the full burden of the reporting requirements defined in the permit.

Reporting Period - January-June______ July-December_____ Year ____

Facility - Pinal Power, LLC
38743 West Cowtown Road, Maricopa, AZ

Fuel Consumption Report

Natural gas burned during reporting period - ___________________ therms

Diesel fuel burned during reporting period - ____________________ gallons

Maximum heat input of biomass boiler (HHV dry)________________ mm btu

Total biomass fuel burned_________________ tons

Operations Report

Power generated during reporting period - _______________________ megawatt-hours

Emissions Report

Emissions of nitrogen oxides - _____________ tons

Emissions of carbon monoxide - ___________ tons

Emissions of particulate matter (PM_{10} / $PM_{2.5}$) - _________ tons

Emissions of volatile organic compounds - ____________ tons

Emissions of hazardous air pollutants - ______________ tons

Emissions of sulfur dioxide - ____________ tons

Compliance Testing Report

Were the following compliance tests performed as required in Section §6.A of this permit?

Incoming material sampling protocol Yes__________ No_______

Weekly compliance sampling Yes___________ No_______

Chlorine testing Yes__________ No_________

Sulfur testing Yes_______ No___________

Heat value determination Yes_________ No_________
Annual heavy metals determination Yes________ No_________

NSPS Performance Test Report

Were the following NSPS performance tests conduced as required in Sections §6.B.2 and §6.B.3 of this permit?

PM NSPS testing Yes________ No______ Date performed__________

NO_X NSPS testing Yes_________ No______ Date performed___________

Non-NSPS Performance Test Report

Were the following Non-NSPS performance tests conducted as required in Sections §6.C of this permit?

Initial Performance tests Yes________ No_______ Date performed____________

PM Non-NSPS testing Yes________ No_______ Date performed_____________

Cooling tower testing Yes________ No_______ Date performed_____________

Baghouse testing Yes_________ No________ Date performed_____________

CO Non-NSPS testing Yes________ No_______ Date performed_____________

VOC Non-NSPS testing Yes________ No_______ Date performed_____________

Hydrogen Chloride Acid (HCl) testing Yes_______ No______ Date performed_____________

Other Reporting Requirements

Were the visual inspections and records of fuel shipments conducted as required in Section §5.I.2.d of this permit?
Yes______ No______

On a separate sheet, describe and explain any monitoring activity or recordkeeping that occurred with respect to the Asbestos NESHAP or Stratospheric Ozone requirements respectively defined in Sections §5.K.2 and §5.K.3 of the permit during the reporting period. Is such a supplemental disclosure attached?

Yes_______ No______

Pursuant to §7.C.5, has natural gas sulfur content been monitored either by:

○ maintaining a contractual commitment to purchase only conforming pipeline natural gas?
Yes____ No___

○ testing and analyzing gas on a daily basis? Yes______ No______

Have opacity screens been performed pursuant to §7.C.7.a of this permit? Yes______ No______

Pursuant to Sections §7.D thru §7.E, were all the recordkeeping requirements met? Yes_____ No_____

Certification by Responsible Official

I certify that, based on information and belief formed after reasonable inquiry, that the statements and information in this report are true, accurate and complete.
Signed ______________________

Print Name______________________

Title ______________________

Date ______________________

Mail to - Pinal County Air Quality Control District
PO Box 987
Florence, AZ 85132