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Technical Support Document
Pinal Power, LLC

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Technical Support Document
Proposed Title V Permit
Pinal Power, LLC, Permit #V20644.000

1. BACKGROUND

A. Applicant

Pinal Power, LLC
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Phoenix, AZ 85032

B. Project Location

This application is submitted by Pinal Power, LLC to propose construction and operation of a 30 MW biomass power project in Pinal County. The project will be located in Pinal County, Arizona, inside the Maricopa City limits in an area zoned industrial bounded by Cowtown Road. The site consists of approximately 45.3 acres and the current address of the site is 38743 West Cowtown Road, Maricopa, Arizona.

C. Attainment Classification

The source is situated in an area that was classified as of January 26, 2011 as nonattainment for PM-2.5 24-hour standard. However, that designation was based on historical data, and does not reflect the most recent monitoring data, which for the 3-year period ending on December 31, 2010, shows an average 24-hour $PM_{2.5}$ value of 31 $\mu g/m^3$. That average actually complies with the 3-year 24-hour standard of 35 $\mu g/m^3$.

The area at least currently remains classified as attainment for all pollutants other than PM-2.5.

However, the most recent annual $PM_{2.5}$ 3-year data set for the nearest monitor reaches 15.4 $\mu g/m^3$, which exceeds the prevailing $PM_{2.5}$ standard of 15 $\mu g/m^3$. Still, due to the designation of the monitor as a "fenceline" or "hotspot" monitor, the area is not and will not be designated as nonattainment under the prevailing annual $PM_{2.5}$ standard. The EPA's implementing regulations, guidance and background discussion preclude using a "fenceline" monitor to establish a violation of the annual $PM_{2.5}$ standard. A "fenceline," or "hotspot" monitor is one that falls within the "zone of influence" of a specific source. In this case, the nearest background monitor in Casa Grande shows a long-term annual average of 10 (or less) $\mu g/m^3$. The "Cowtown" monitor located approximately 1-1/2 miles from this proposed facility lies next to an existing feedlot complex. A 2004 speciation study indicated that the dominant fraction of observed $PM_{2.5}$ consisted of manure. Since the annual $PM_{2.5}$ average at Cowtown exceeds 15 μg/m^3,[1] it is reasonable to conclude that that additional 50%+ impact is due to the adjoining feedlots. Since the EPA's guidance characterizes a monitor that sees a 10% or greater impact from a single source as falling within the "zone of control" of that source, the Cowtown monitor is clearly a "hotspot" monitor that is substantially affected by emissions from the adjoining feedlots. As discussed further below, the incremental annual $PM_{2.5}$ impacts from this proposed facility will not change the "hotspot" character of the existing monitor.

In addition, and 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.

D. Classification for Purposes of Maximum Allowable Increases or "Increments"

The site of this proposed facility is classified as a default Class II area for all pollutants for which the area remains classified as attainment.

2. AGENCY AUTHORITY

The Arizona Legislature granted the Pinal County Board of Supervisors to establish a program to permit certain sources of regulated air pollutants. Generally, see ARS §§49-470 *et seq.* (ARS Title 49, Chapter 3, Article 3.)

The Pinal County Board of Supervisors adopted a Code of Regulations, which among other things establishes such a program for permitting stationary sources. Generally, see the Pinal County Air Quality District Code of Regulations, as amended October 13, 2010.

In accord with A.R.S. §49-480, Pinal County's permit program constitutes a "unitary" program, with a permit conferring both authority to construct and authority to operate.

Under authority of CAA §110, the EPA has approved relevant portions of the Pinal County permitting program as an element of the Arizona SIP. In particular, see 61 Fed. Reg. 15717 (4/9/96). Among other things, that SIP-approval approved Pinal County's minor new source review program. A separate EPA SIP-approval allows Pinal County to define federally enforceable permit limitations. See 60 Fed. Reg. 21440 (5/2/95).

1 The most recent 3-year annual average reports a 15.4 μg/m3 PM2.5 average.

Under authority of CAA §§501 *et seq.*, the EPA has conferred interim and final approval upon Pinal County's Title V permitting program. See 61 Fed. Reg. 55910 (10/30/96), 66 Fed. Reg. 48402 (9/20/01).

3. PROCESS DESCRIPTION

A. Equipment

1. Biomass boiler
2. Automated fuel feed system
3. Boiler feed water treatment
4. Steam turbine
5. Steam condensor
6. Evaporative cooling tower

B. General Process

The proposed project is a wood-waste biomass energy plant producing 30 MW of electrical output. It will be fueled primarily by municipal green waste and agricultural wood waste derived from the agricultural operations in the area within 30 miles of the plant. The project will consume 260,000 bone dry tons (BDT) of wood waste annually. The boiler will generate 1250 PSIG superheated steam at 950°F for delivery to the steam turbine generator to achieve the maximum possible efficiency for a wood burning facility. The proposed boiler will utilize two 62.5 MM Btu natural gas burners that will have a burner design heat input rate of no more than 125 MM Btu/hr when combusting natural gas. This boiler will also be capable of combusting wood at a maximum design heat input rate of 402 MM Btu/hr.

The plant will include an automated fuel feed system, a boiler feed water treatment, a boiler, a steam turbine, a condenser, a rotoclone dust collector, an Electrostatic Precipitator (ESP) and evaporative cooling tower.

The plant will be interconnected to the grid via a 69 KV transmission line terminating at an APS transmission line approximately 13 miles from the project.

The project will be located on a level site consisting of 45.3 acres, providing sufficient area to build the facility and to store up to 60 days of fuel onsite.

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

The proposed project is a major source for purposes of Title V but a minor source with respect to Prevention of Significant Deterioration (PSD) requirements and is therefore not subject to Best Available Control Technology (BACT) requirements. Emissions of all criteria pollutants will be less than 250 tons per year.

C. Operational Limitation

Permittee shall not exceed the average heat input capacity of the boiler to more than 410 MMBtu/hr, based on a daily average.[2]

D. Fuel

1. Bio-mass Feedstock

The proposed project will be fueled primarily by municipal green waste and agricultural wood waste, guayule, a plant which is a source of natural rubber and other feedstock generated from agricultural operations in the area within 30 miles of the plant. This fuel will be acquired under long term fuel contracts with the local agricultural operators supplying high quality wood fuel (as described above) for the project and will be processed and delivered to the plant ready for consumption.

In addition, the boiler design will also allow the combustion of other waste biomass fuels commonly available in the region such as in-forest residues and clean urban wood-waste sourced from the Phoenix area. Fuel in the form of wood chips, will be stored in a fuel building prior to being delivered to the boiler feed system. Additional fuel will be maintained in storage piles adjacent to the plant.

No railroad ties or other chemically treated wood, or construction and demolition material will be burned at the facility.

Although not a permit limitation, preliminary expectations project that about 60% of biomass fuels will be drawn from landfill diversions, and the remainder from either long-term or spot contracts with agricultural operators and other accessible sources of biomass. To avoid quality control issues associated with accepting questionable product from transient providers, the permit does require that incoming biomass feedstock either be delivered

2 On 5/31/11, applicant requested an increase from 389.65 MMBtu/hr to 410 MMBtu/hr.

pursuant to a contract executed with Pinal Power, or that the product either be transported by Pinal Power or by a carrier who has contracted with Pinal Power for delivery.

Moreover, the permit does not provide for on-site size-reduction of materials, effectively requiring that all incoming product will within the required operationally required size-specification when delivered to the site.

Biomass materials will be acquired through three commercial channels. Operating under contract, a landfill operator or a contractor working with a landfill operator will manage the selection, diversion, and size reduction of biomass materials. Operating under a contract, other operators, principally expected to be agricultural enterprises, will provide biomass of a defined character on a recurring basis. Lastly, the Permittee or the Permittee's agents will acquire materials on a spot-basis, and the Permittee will be directly responsible for the selection and size-reduction of the biomass materials.

The BTU content of the received fuel will vary due to moisture content which is expected to range from 25-50%, averaging 30%. The plant will be designed to handle moisture contents from 25 to 50%, allowing for higher moisture content of the fuel in the winter months.

Although not a permit limitation, the operational requirements for a stoker-type boiler will dictate that the biomass fuel feedstock consist of a 4-inch-and smaller ('4" minus') product with limited "fines." Notably, the permit contemplates that all biomass feedstock materials will conform to the size-specification when they arrive at the site. That is, the permit does not provide for on-site grinding, chipping or other size-reduction of biomass materials.

Water for boiler and cooling tower make-up will be provided by an on-site well with back-up provided by local water agencies. The project will also treat the resulting wastewater stream in its own wastewater treatment facility.

2. Natural Gas

The facility will also use clean burning natural gas during startups, shutdowns and when required to provide supplemental fuel. The startup process fires the boiler with natural gas to preheat the boiler prior to normal fuel feed initiation, to maintain emission control. A natural gas supply line is located on the property with sufficient capacity to supply the plant during these operations. Pipeline quality natural gas will be supplied from the pipeline with a sulfur concentration of less than 5 grains per 100 dry standard cubic feet based on FERC tariffs from the supplier.

3. Fuel Assurance

Fuel quality assurance involves a number of considerations.

The operator is principally concerned with the heating value, moisture content and ash content of the fuel, and based on those considerations the operator has defined objective criteria to define "unacceptable" material.[3]

To protect against generating harmful air pollutants, and for purposes of regulatory compliance, a limited list of acceptable materials has been defined, and a host of items are classified as "prohibited" material.

As a preliminary control, Permittee is required to either obtain biomass material under a contract that obligates the source to agree to exclude prohibited material, or the Permittee must accept direct responsibility excluding prohibited materials.

For regulatory purposes, the sulfur content of the fuel must be monitored. And to avoid triggering additional air quality regulatory requirements, chlorine content must be quantified in order to apply corresponding control efforts to control HCl emissions.

The permit calls for a two-tiered testing program to manage fuel-quality, and in particular fuel chlorine and sulfur content.

First, Permittee is required to conduct representative inspection and sampling of incoming biomass to verify the absence of prohibited materials, and to characterize the heating value, chlorine content and sulfur content for each source and fuel type. That extent of that incoming sampling is scaled to the quantity of biomass for that source and type. That incoming sampling requires a mass-weighted prediction of the contribution of chlorine and sulfur to the primary fuel reservoir.

Second, Permittee is required to conduct a weekly sampling to test material on the feed conveyor to the boiler, and to again determine heat content and sulfur content for purposes of assessing compliance with permit limitations.

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3 As a brief attempt at vocabulary reconciliation, the thermodynamic terms LHV ("lower heating value") and HHV ("higher heating value") alternatively refer to the type of heat energy resulting form combustion. To the extent the combustion process chemically generates water, it takes energy to vaporize the water and the resulting heating potential is designated the LHV. On the other hand, if the heat of vaporization is recovered by condensing the water and cooling that liquid to ambient temperature, the aggregate heating potential is designated as the HHV. In an actual operating facility, unless the stack is equipped with a heat exchanger/condensor, the heat of vaporization is not actually recovered. As defined, both of those terms are assessed on a "dry" basis, assuming that the material combusted is dry and free of any entrained moisture. Because emissions reflect the mass of material actually burned, regulatory limitations are expresseed in terms of "HHV - dry".

However, as a practical operational matter, material is almost never truly "dry." This facility contemplates boiler feed with a nominal 30% moisture content, meaning that for practical operation, achieving the desired actual power output will require firing at a fuel feed rate that accounts for the additional moisture content. In effect, the required fuel feed rate is a function of "LHV - wet". From the operator's perspective, the value biomass feedstocks will similarly be based on heat content expressed as "LHV - wet."

That conveyor sampling also determines the chlorine content value used to adjust the rate-of-control required to control HCl emissions.

E. Controls

1. NO_X Controls

Pinal Power proposes to install Selective Non-catalytic Reduction (SNCR) system to limit NO_X emissions to 0.14 lb/MMBTU (on a 24-hour block average basis), or 59.22 lb/hr[4] at the maximum operating rate of the proposed boiler.

Add on controls such as SNCR systems are widely used technologies for controlling NO_X emissions from combustion sources.

In the SNCR process, a reagent reacts with NO_X to form nitrogen and water but no catalyst is used to aid the reaction and therefore the reaction occurs at a higher temperature. The SNCR reagent can be urea, aqueous ammonia or anhydrous ammonia and is typically vaporized and mixed with hot flue gas from the combustion device. Ammonia slip from the SNCR will be limited to 20 ppm.

2. CO Controls

CO emissions will be controlled through the use of proper boiler design and good combustion practices. For the McBurney boiler, the boiler design and good combustion practices will be used to reduce CO to 0.14 lbs/MMBTU. The design includes a large furnace, which will allow for greater burnout time and conversion of CO; inclusion of an overfire air system which adds extra air and facilitates complete combustion; use of refractory to improve combustion efficiency; and use of flue gas re-circulation.

Guidance on good combustion practices is available from the EPA's Air Technical Website at http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf. The table below provides examples of practices that will be followed by Pinal Power to ensure that good combustion practices are followed to reduce CO and VOCs to the extent possible.

Good Combustion Technique	Examples of Practices

4 56.28 x 410/389.65 = 59.22 lb/hr.

Operator practices	•Official documented operating procedures, updated as required for equipment or practice changes. •Procedures include startup, shutdown, malfunction. •Operating logs and recordkeeping procedures.
Maintenance knowledge	•Training on applicable equipment and procedures
Maintenance practices	•Official documented maintenance procedures, updated as required for equipment or practice change. •Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved. •Maintenance logs/recordkeeping.
Stoichiometric fuel/air ratio	•Burner and control adjustment based on visual checks. •Burner and control adjustment based on continuous or periodic monitoring of O_2 and CO. •Oxygen trim control •CO control •Safety interlocks
Fuel quality	•Monitor fuel quality •Meet fuel sizing specifications and checks
Combustion air distribution	•Adjustment of air distribution system based on visual observations or continuous periodic monitoring.

3. PM Controls

Pinal Power proposes to install a mechanical collector (a cyclone) followed by an ESP to achieve an emission limit of 0.020 lbs/MMBTU for PM_{10} control.

PM_{10} is produced by combustion processes as unburned solid carbon (soot), unburned vapors or gases that subsequently condense and the unburned portion of the fuel (ash).

Electrostatic precipitators (ESP) are the most popular add-on control technologies to control PM_{10} emissions from a boiler. ESPs remove particles from an exhaust stream by imposing an electrical charge on the particles and then attracting them to an oppositely charged plate. The dust collected on the charged plate is periodically removed by vibrating of the plates. Often a mechanical collector, such as a rotoclone, is used to remove larger particulate matter before the exhaust reaches the primary control device which is the ESP.

The cooling tower will be equipped with drift eliminators to minimize particulate matter emissions.

4. VOC Controls

Pinal Power proposes to use good combustion practices to control VOCs to 0.017 lbs/MMBTU at the maximum operating rate of the proposed boiler. VOC emissions are generally the result of incomplete combustion of fuel. In the case of wood, volatiles, released as fuel are heated in the furnace, some portion of which escapes combustion by improper mixing with oxygen.

5. SO_2 Controls

Pinal Power proposes that no control system is feasible for reducing SO_2 emissions from a stoker-type, wood fired boiler. The boiler SO_2 emission rate will be 0.06 lb/MMBTU, which is equivalent to a mass emission rate of 10.57[5] lbs/hr.

6. HCl Controls

The potential HCl emissions generated by the combustion of biomass could exceed the 10 tpy major source threshold which would require that the facility comply with the requirements of a recently promulgated Maximum Achievable Control Technology (MACT) standard in 40 CFR Part 63 Subpart DDDDD.

Potential emissions were calculated by PCAQCD in 2 different ways:

1) Using an AP-42 emission factor (from Table 1.6-3), and assuming a maximum heat input rate pf 410 MMBtu/hr, uncontrolled emissions of HCl would be 32.07 tpy.[6]

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5 10.05 x 410/389.65 = 10.57 lb/hr.

6 The application initially posited a 389 MMBtu/hr heat input limitation, which correlated to 30.48 tpy of HCl. The heat input limit was relaxed to 410 MMBtu/hr. 30.48 x 410/389 = 32.07 tpy.

2) We assumed a worst case scenario of 0.02% chlorine content in the wood (typical of bark which is more conservative), a fuel throughput of 131.7 tons per hour (from the application) and a worst-case scenario of Cl-to-HCl conversion of 50%. The applicant estimated that a 20% Cl-to-HCl conversion and that a 0.005% chlorine content are more typical. (See Valorie Thompson's e-mail from 5/11/11). Using PCAQCD's more conservative assumptions, uncontrolled HCl emissions were calculated at 108.48 tons per year.

Both calculations show the need for control of HCl, and the applicant has proposed using Trona (trisodium hydrogendicarbonate dihydrate) injection.

Trona is a dry sorbent utilized throughout industry for the removal of SO2, and it also removes HCl and mercury. It is a widely used technology due to its low capital cost, small installation foot print, ease of operation and flexibility to fuel changes.

A literature review indicates that trona can provide up to 98% removal of HCl from an exhaust stream. PCAQCD has estimated that to remain at 70% of the major source threshold, the trona will have to provide at least 93.5% control efficiency. Since the control efficiency is determined by the amount of trona injected (as indicated in the Valorie Thompson e-mail from 5/11/11, it takes "twice as much trona as HCl" to achieve 95% control, and 3-4 times more to achieve 99% control efficiency), to achieve 93.5%, the applicant is going to have to inject approximately 0.025 tph, or 52.7 lb/hr, (HCl emission rate of 108.48 tpy times 2).

Based on a worst case anticipated chlorine fraction of 0.02 % in the 131.73 ton per hour biomass feedstock fuel rate, 0.03 lb/hr of trona will achieve 93% of control efficiency.

The permit requires a testing program to empirically develop a facility-specific relationship to govern on-going Trona injection rates.

7. Control Sequence

The SNCR will commence operation when the boiler reaches operating temperatures of approximately 1500 ^{o}F. The system will inject the reagent into the boiler exhaust to reduce NO_X to form nitrogen and water. The boiler exhaust gas will be treated with trona to reduce emissions of HCl.

Following the treatment of the boiler exhaust through the SNCR and trona process, the exhaust gases will be routed through the rotoclone precipitator, which will collect the remainder of the fly ash.

4. EMISSION CALCULATIONS

A. Fuel Receiving, Handling, Storage and Processing

The fuel receiving, handling, storage and processing area will be designed to accommodate biomass feed stocks as received at the facility. Biomass will be brought to the site in covered trucks already shredded and ready to process. After weighing at the scale, the trucks will proceed to the truck dumping stations where the contents of the truck will be emptied into truck dumpers. The system will include one or two truck dumpers and a high capacity reclaimer which is a mechanical device with arms to move the wood fuel from truck delivery to the fuel storage building. Dual independent conveyor systems will move the fuel from the fuel storage building to the boiler fuel metering system. All fuel handling will be enclosed to reduce fugitive dust emissions.

1. Fuel Handling Operations

The maximum fuel throughput for fuel handling operations is based on the input rate of 131.73 tons per hour.

$EF = k * (0.0032 * (U/5)^{1.3} / (M/2)^{1.4})$........ ....(AP-42, Table 13.2.4-1.(1))

Results from this calculation are given in Table 6 of this TSD.

Table1: Values Used for the Constants for Fuel Handling Equation

Constant	Description	Value Used	Unit
EF	Emission Factor	N/A	lb/ton
k	Particle Size Multiplier	0.74 for PM	N/A
		0.35 for PM_{10}	N/A
		0.053 for $PM_{2.5}$	N/A
U	Mean Speed Wind[7]	5.12	miles per hour
M	Moisture Content of Material	30	%

7 The mean wind speed is from Cowtown meteorological data.

2. Dozer Use on Biomass Storage Areas Bulldozing Overburden

EF_{PM} (lb/hr/dozer) = $(5.7*s^{1.2}) / (M^{1.3})$..................................(AP-42, Table 11.9-1)

Results from this calculation are included in Table 6 of this TSD.

Table 2: Values Used for the Constants in Biomass Fuel Storage Equation

Constant	Description	Value Used	Unit
EF_{PM}	Emission Factor for PM	N/A	lb/hr/dozer
EF_{PM10}	Emission factor for PM_{10}	N/A	lb/hr/dozer
$EF_{PM2.5}$	Emission Factor for $PM_{2.5}$	N/A	lb/hr/dozer
S	Material Silt Content	0.16	%
M	Material Moisture Content	30	%

3. Wind Erosion..(AP-42, Section 13.2.5)

$u_{10,i} = u_{z,i}$ (ln(10/0.005) / ln (z/0.005))

Results from this calculation are include in Table 6 of this TSD.

Table 3: Values Used for the Constants in Wind Erosion Equation

Constant	Description	Value Used	Unit
$u_{10,i}$[8]	fastest mile wind speed for the ith disturbance normalized to 10m anemometer height	14.35	miles per hour

8 The mean wind speed is from Cowtown meteorological data.

$u_{z,i}$[9]	fastest mile wind speed for the ith disturbance normalized to 10m anemometer with height of z meters	12.08	miles per hour

B. Boiler and Steam Turbine / Generator

The main emission source of the proposed project is the bio-mass fueled boiler. The proposal includes installation of a water-wall boiler equipped with a vibrating grate allowing precise combustion and emission control in the combustion stage. The boiler will generate 1250 PSIG superheated steam at 950°F for delivery to the steam turbine generator to achieve maximum efficiency for a wood burning facility. The boiler island will include a steam generator, superheater, airheater and economizer to maximize steam production efficiency.

1. Uncontrolled Emissions

Uncontrolled emissions for various pollutants were calculated from EPA's AP-42, Section 1.6, emission factors for wood residue combustion, assuming bark and wet wood fired boiler. Table 5 lists the uncontrolled emissions.

2. Controlled Emissions

Permittee has volunteered to take operational limitation on the heat input capacity of 410 MMBtu/hr.

Emission limits in Table 6 are based on the Best Available Control Technology evaluation and determination of BACT based on a review of EPA's BACT/LAER Clearinghouse for biomass facilities. Controlled / allowable emissions are listed in Table 6 of this document.

3. Start-up and Shutdown Emissions

The facility will also use clean burning natural gas during startups, shutdowns and when required to provide supplemental fuel. The startup process fires the boiler with natural gas to preheat the boiler prior to normal fuel feed initiation, to maintain emission control.

9 The mean wind speed is from Cowtown meteorological data.

Emission factors for natural gas emissions were derived from EPA's AP-42, Section 1.4, Natural Gas Combustion (large, post NSPS boiler). Table 7 below lists the start-up and shutdown emissions.

4. Hazardous Air Pollutants Emissions (HAPs)

Application lists various hazardous air pollutants (HAPs) emitted from the facility during the operation of the boiler. Of all the HAPs, hydrogen chloride is the only one that is emitted at 66% of the major source threshold for a single hazardous air pollutant.

According to the Handbook of Biomass Combustion and Co-Firing, chlorine is present in biomass fuels in varying amounts, ranging from 50 mg/kg in spruce wood chips to 20,000 mg/kg in grass and hay. Chlorine vaporizes almost completely during combustion, forming HCl, Cl and alkali chlorides. With decreasing flue gas temperatures, alkali and alkaline earth chlorides will condense in the boiler section on fly ash particles or on the heat exchanger surfaces. Subsequently, part of the Cl will be bound in the fly ash while the rest will be emitted as HCl in the flue gas.

C. Fly Ash Handling, Storage and Shipment

The combustion of biomass in the boiler will result in the formation of bottom ash and fly ash. The resultant amount of ash is determined by the type of fuel. Bottom ash will be in the form of large solid particles and will be removed from the boiler and stored in a metal container for future removal off site. An enclosed conveyor or similar system will be used to transport the flyash from the baghouse to the flyash storage silo. The conveyors and the drop points associated with ash handling will be enclosed. Following amounts are the maximum amounts of fly ash that can be handled at each step of the process:

Bottom ash handling - 22,916 tons per year (2.616 tons per hour)

Fly ash handling - 34,427 tons per year (3.93 tons per hour)

Ash storage = 57,378 tons per year (6.55 tons per hour)

Ash shipment = 175,200 tons per year (20 tons per hour)

$EF = k * (0.0032 * (U/5)^{1.3} / (M/2)^{1.4})$........ ....(AP-42, Table 13.2.4-1.(1))

Results from this calculation are included in Table 6 of this TSD.

Table 4: Values Used for the Constants in Fly Ash Handling Equation

Constant	Description	Value Used	Unit
EF	Emission Factor		lb/ton
k	Particle Size Multiplier	0.74 for PM	
		0.35 for PM_{10}	
		0.053 for $PM_{2.5}$	
U	Mean Speed Wind	5.12	miles per hour
U_{max}	Maximum Wind Speed	27.02	Miles per hour
M	Moisture Content of Material	5 (bottom ash); 1.5 (fly ash)	Percent
M_{min}	Minimum Content of Material	1	%

D. Cooling Tower Particulate Emissions

In an application revision[10], the applicant characterized PM-2.5 and PM-10 emissions from the cooling tower.

Citing a published reference, the revision posits that only small droplets escaping from the cooling tower produce PM-10:

- A variety of sizes of water droplets pass through the drift eliminators and escape;
- Droplet size distribution for this facility can be assumed based on a 1988 test of a drift eliminator system, the relative size distribution does not vary for a system, and that a less effective drift eliminator system will not produce additional small droplets;
- The number of droplets escaping is a linear function of the water circulation rate;
- Evaporation produces uniform spherical particles that vary in size as a function of water droplet size and TDS concentrations in the cooling water;
- Accordingly, applicant mathematically posits that at anticipated TDS concentrations,

10 V.Thompson e-mail, 5/26/2011.

85%, or more, of particulate emissions from the cooling tower are larger than PM-10 and therefore are not PM-10.

Citing a separate reference, the revision posits that PM-2.5 constitutes 60% of PM-10.

The revision further calculates anticipated PM-2.5 emission rates based on those considerations, coupled with a 0.001% drift rate[11], a 46,262 gpm cooling tower and a range of anticipated TSD concentrations. The worst case anticipated PM-2.5 emission rate reaches 0.2313 lbs/hr, which would equate to 0.355 lbs/hr of PM-10 emissions.

5. POTENTIAL AND ALLOWABLE EMISSIONS

A. Boiler - Uncontrolled Potential Emissions

Table 5: Uncontrolled Emissions from Boiler

Pollutant	Capacity (lbs/ MM Btu)	Capacity (lb/day)	Emissions (tpy)
NO_X	0.35	3,273	597.3
CO	0.14	1,309	238.9
SO_X	0.06	561	102.4
PM_{10}	0.50	4,676	853.3
VOC	0.017	159	29.0
HAPs			8.34

B. Facility-wide Controlled Emissions

Table 6: Allowable Emissions

Emission Unit	Pollutant	Emission Limits (lb/MM Btu)[12]	Uncontrolled Emissions (tpy)	Allowable Controlled Emissions (tpy)	Proposed Controls	Control Efficiency (%)

[11]Upon EPA's request, permittee agreed to a lower drift rate of 0.0005%. See 8/1/11 e-mail from Valorie.

12 Emission limits are based on the control requirements in the permit and review of EPA's BACT/LAER Clearinghouse for biomass facilities.

Fuel Handling	PM_{10}	N/A	0.22	0.22	Enclosures	N/A
	$PM_{2.5}$	N/A	0.03	0.03	Enclosures	N/A
Dozer Use	PM_{10}	N/A	0.009	0.009	N/A	N/A
	$PM_{2.5}$	N/A	0.001	0.001	N/A	N/A
Wind Erosion	PM_{10}	N/A	0.35	0.35	Paving/Stabilization	N/A
	PM2.5	N/A	0.088	0.088	N/A	N/A
Boiler	NO_X	0.14		105.60	SNCR	60%
	CO	0.14	238.9	147.90	Good combustion practices	86%
	SO_2	0.06	102.4	44.02	Low-sulfur Fuel	N/A
	$PM_{10}/PM_{2.5}$	0.020	853.3	35.94	Cyclone & Electrostat	96%
	VOC	0.010	29.0	17.61	Good combustion practices	40%
	HAPs	0.019	N/A	8.34	Good combustion practices	N/A
Fly Ash Handling	PM_{10}	N/A	0.2	0.2	Enclosure/ Baghouse	N/A
	$PM_{2.5}$	N/A	0.03	0.03	Enclosure/ Baghouse	N/A
Fly Ash Shipment	PM_{10}	N/A	0.30	0.30	N/A	N/A

	$PM_{2.5}$	N/A	0.04	0.04	N/A	N/A
Cooling Tower[13]	PM_{10}					

C. Start-up and Shutdown Emissions

Table 7 below provides an estimate of uncontrolled start-up and shutdown emissions from combustion of natural gas during start-up and shut-down events.[14] There will be a total of 240 startup and shutdown events, each one conservatively estimated to last 24 hours.

Table 7: Start-up and Shutdown Emissions

Pollutants	Emission Factor (lb/MMSCF)	Emissions (lbs/hr)	Emissions (tpy)
NO_X	1.9E+02	65.19	7.82
CO	8.40E+01	28.82	3.46
Total PM (PM_{10} & $PM_{2.5}$)	7.60E+00	2.61	0.31
SO_X	6.00E-01	0.206	0.02
VOCs	5.50E+00	1.89	0.23
Methane	2.30E+00	0.79	0.09

D. Greenhouse Gas Emissions

According to the PSD and Title V Permitting Guidance for Greenhouse Gases, published by the EPA on November 2010, as long as the permit is issued before July 1, 2011, greenhouse gas emissions are not subjected to the Title V permitting requirements.

Permittee however addressed these emissions in an e-mail sent to PCAQCD on September 27, 2010. The potential greenhouse gas emissions from using natural gas as a fuel and from the biomass boiler are 348,289 metric tons per year.

On October 30, 2009, the U.S. Environmental Protection Agency (EPA) published the final version of the Mandatory Greenhouse Gas (GHG) Reporting Rule in the

13 Incomplete data - 6/6/11 - dpg.

14 6/2/11 - Please verify.

Federal Register. Affected facilities that generate equivalent amounts of CO_{2e} (CO_2 equivalent based greenhouse warming potential) equal to or more than 25,000 metric tons are required to monitor and report emissions. On-going annual GHG reporting will be due March 31 of each calendar year for GHG emissions in the previous calendar year. This report shall be submitted directly to EPA.

6. APPLICABLE REQUIREMENTS

A. Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units - Subpart Db [40 CFR Part 60]

This subpart is applicable to any industrial, commercial or institutional steam generating unit that commences construction, modification or re-construction after June 19, 1984 and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 mm/Btu/hr).

1. Particulate Matter Standards

This subpart defines the emissions of particulate matter to be limited to 0.030 lb/MM Btu heat input and requires that any gases discharged to the atmosphere do not exhibit greater than 20% opacity standard.[15] These limitations do not apply during start ups, shut downs or malfunctions.

2. Sulfur Dioxide Standards

This subpart states that any units firing very low sulfur oil, gaseous fuel, a mixture of these fuels, or a mixture of these fuels with any other fuels with a potential SO_2 emission rate of 140 ng/J (0.32 lb/MM Btu) heat input or less are exempt from the SO_2 emission limit of 0.2 lb/ MM Btu.

The application, and reasoned conjecture backed by the permit-imposed testing regimen to verify fuel-sulfur content in the biomass fuel, both support a conclusion that SO_2 emissions from the proposed boiler will not exceed the limiting SO_2 emission rate under the NSPS Subpart Db of 0.32 lb/MM Btu. Therefore, the permit is based on a conclusion that the exemption from the sulfur dioxide standards applies.

3. Nitrogen Oxide Standards

This subpart defines emissions of NO_X to be limited to 0.30 lb/MMBtu heat input. This NO_X emission limit shall apply at all times including periods of startup, shutdown or malfunction.

15 20% opacity standard includes 6 minute average, except for one 6-minute period per hour of not more than 27% opacity.

B. CAM - Compliance Assurance Monitoring

The CAM rule is applicable to pollutant-specific emission units at major sources. Given that NO_X and CO emissions from the boiler will be controlled by a SCR/SNCR and a catalyst bank, each must comply with the CAM requirements. However, since 40 CFR Part 75 already requires NO_x CEMS for the boiler and the Permittee is installing CEMS for CO, CAM rule identifies several exemptions, including 40 CFR Part 64.2(b)(vi) for emission limits or standards for which a Part 70 or 71 permit already specifies a continuous compliance determination method 40 CFR Part §64.2.(b)(vi), those CEMS inherently satisfy CAM requirements.

However, CAM rule is applicable for particulate matter, including both $PM_{2.5}$ and PM_{10}, since those pollutants satisfy all the following CAM requirements in accordance with 40 CFR 64.2[16].

1. The pollutant-specific emission unit (PSEU) is located at a major source that is required to obtain a Part 70 permit;

2. The PSEU is subject to an emission limitation or standard for the applicable regulated air pollutant that is not exempt, namely the synthetic minor limitations that avoid triggering PSD for $PM_{2.5}$ and PM_{10};

3. The PSEU uses an add-on control devices, namely the rotoclone and the ESP, to achieve compliance with such an emission limitation or standard;

4. The PSEU has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than major source thresholds;

5. The PSEU is not an exempt backup utility power emissions unit that is municipally owned.

For all <u>large pollutant specific emissions units</u>, with the potential to emit (taking into account control devices to the extent appropriate under the definition of this term in §64.1) the applicable regulated air pollutant in an amount equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source, the owner or operator shall submit the information as part of an application for an initial part 70 or 71 permit.

For <u>other pollutant-specific emissions units</u> a CAM plan is due as a part of the

16 Pinal Power will submit a different application for a CAM Plan that follows EPA guidance on development of CAM plans for equipment utilizing fabric filter baghouses.

application for the first permit renewal. Since the post control particulate matter emissions do not reach 100% of the major source threshold, CAM plan for particulate matter is due upon first renewal of this permit as a part of Title V permit requirements.

Despite the seemingly illogical conclusion, EPA Region 9 has verfied that actual submittal of a CAM plan is not required before the submittal of the 5-year permit renewal application for this facility.

C. RACM Implementation

The particulate matter controls on the facility, namely the rotoclone and ESP, are believed to qualify as reasonably available control measures, or RACM.

However, the Clean Air Act requires that RACM measures be SIP-approved. Since a curative SIP has not been proposed or approved with respect to $PM_{2.5}$ (or PM_{10}), and this permit is not itself being proposed as a SIP revision, actual designation of those controls as RACM will need to await actual adoption of rules mandating that level of control for a facility such as this.

D. Acid Rain Applicability and Requirements

Since the facility may use natural gas during upset conditions to provide electricity to the grid through contract requirement and as an electric generating facility with the potential to generate more than 25 MW, the facility is subject to the requirements of the Title IV Acid Rain Program.

E. Testing Requirements

Performance testing is required to demonstrate compliance with the emission rates specified in the permit application. Specifications regarding the approved test methods, protocol, reporting requirements and testing frequency are specified in the permit. These tests shall be performed at the maximum practical production rate.
A test plan protocol for each test shall be submitted to the District at least thirty (30) days before the testing.

1. NSPS TESTING

a. Particulate Matter

To determine compliance with the PM emission limits and opacity limits under §60.43b, the owner and 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 or Control Officer using approved test methods and procedures. Detailed test description is given in Section §6.B.2 of the permit.

b. Sulfur Dioxide

In conducting the performance tests required under §60.8, the owner or operator shall use the methods and procedures in appendix A including fuel certification and sampling methods. Detailed test description is given in Section §§6.B.1, 7.C.6 and 7.C.7 of the permit.

c. Nitrogen Oxides

To determine compliance with the emission limits for NO_X under §60.44b, 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). A detailed test description is given in Section §6.B.3 of the permit.

2. NON-NSPS TESTING

a. Particulate Matter

The Permittee is required to conduct an initial performance test for PM (PM_{10} and $PM_{2.5}$) on the boiler within 180 days after startup of the facility, and subsequent performance tests every year. Additional performance tests will be performed at the request of the Director. This test also requires to determine PM_{10} and $PM_{2.5}$ control efficiency by the rotoclone/ESP.

b. Nitrogen Oxides, Carbon Monoxide, Sulfur Dioxide, Volatile Organic Compounds, and Ammonia

The Permittee is required to conduct an initial performance test for NO_X, CO, SO_2, VOC, HCl, (HAPs) and ammonia[17] on the boiler within 180 days after startup of the facility. Performance test frequency for different pollutants is listed in Section §6.B of the permit. Additional performance tests will be performed at the request of the Director.

Testing for VOC is being required even though there are no explicit

17 Ammonia testing is required to make sure that the facility is in compliance with the 20 ppm ammonia slip limit for the SNCR.

limits for VOC emissions in the permit. This requirement is to ensure that the emissions estimates provided as part of the permit application were representative of actual emissions.

c. Hazardous Air Pollutants

The Permittee is required to conduct an initial performance test for HCl HAPs and on the boiler within 180 days after startup of the facility, and subsequent performance tests every two years. Additional performance tests will be performed at the request of the Director.

Data from this initial source test shall be used to develop a parametric equation based on the biomass firing rate to the boiler to define the amount of trona that needs to be injected to control HCl emissions.[18]

d. Heating Value

As an integral element of the weekly fuel-chlorine and fuel-sulfur quantification, Permittee is required to conduct weekly tests on the wood waste to determine the heating value of the fuel.

e. Opacity Screenings[19]

In addition to the monitoring requirements pertaining to visible emissions and opacity, the permit requires semi-annual opacity testing, using Reference Methods 9 and 203C, of each transfer point at the biomass fuel handling system, the flyash handling and load-out system and all the vents, exhausts and stacks from the production facility.

7. AIR QUALITY IMPACT ASSESSMENT

A. Input Parameters

1. Boiler Emission Rates

Table 8 below gives the emission rates for the various pollutants that were

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18 The trona injection is based on the assumption that chlorine in the fuel is converted to approximately 50% HCl and thus is a conservative basis to ensure proper controls.

19 40 CFR Part 60, Subpart Db, Section §60.48b.(a) requires the facility to install, calibrate, maintain and operate a continuous opacity monitoring system (COMS) for measuring the opacity of emissions discharged to the atmosphere.

used to conduct the modeling. For conservative purposes, annual controlled emissions were modeled as though the facility could operate for 8,760 hours per year. To provide a worst-case analysis of potential annual impacts, emissions were assumed to operate at their maximum hourly emission rates at all times.

Table 8: Pollutant Emission Rates

Pollutant	Lbs/day	g/sec
CO	1,351	7.09
NO_X	1,351	7.09
SO_2	561.10	2.95
PM_{10}	192.96	1.013

2. Modeling Parameters for Point Source

Permittee conducted an air quality impact assessment on the McBurney Biomass Boiler. Table 9 below specifies the various release parameters for point source (boiler) used to conduct the modeling . Downwash of the plume due to structures on the site was included.

Table 9: Modeling Parameters for the Point Source

Parameter	Value
UTM East, m (NAD 83, UTM Zone 12)	408172.91
UTM North, m (NAD 83, UTM Zone 12)	3653318
Source Base Elevation (m)	370
Stack Height (m)	36.576
Stack Diameter (m)	2.44
Stack Exit Velocity (m/s)	14.87
Stack Exit Temperature (K)	436
Orientation	Vertical

3. Modeling Parameters for Volume Sources

For evaluating PM_{10} impacts, additional sources associated with fuel and ash handling were included in the modeling. Table 10 below specifies the parameters used for the volume sources.

Table 10: Modeling Parameters for the Volume Sources

Source	UTM East (m)	UTM North (m)	Source Base Elevation (m)	Release Height (m)	Initial Horizontal Dimension (m)	Initial Vertical Dimension (m)
Bulldozing	408099	3653361	369.72	2.54	28.35	2.36
Ash Shipment	408218	3653258	369.72	2.0	1.63	1.86
Truck Dump 1	408099	3653380	369.72	2.0	1.12	1.86
Truck Dump 2	408207	3653379	369.72	2.0	1.12	1.86
Fuel Handling	408222	3653345	369.72	7.62	14.18	7.09
Fly Ash Handling	408217	3653270	369.72	15.25	2.93	14.19

4. Downwash Parameters

Downwash of the plume due to structures on the site was included. Table 11 below shows the main structures on the site.

Table 11: Downwash Structures

Structure	Length (m)	Width (m)	Height (m)
Steam Turbine Building	39.36	23.04	10.67
Boiler Housing	21.12	21.12	34.63
Control System Housing	18.24	9.60	25.91
Tower Building	30.72	10.40	10.67
Cooling Tower	60.48	17.97	10.67
Ash Handling System	23.03	9.60	19.20

B. Air Dispersion Model Parameters

1. Air Dispersion Model

   Air dispersion modeling was completed using EPA's approved regulatory air dispersion model, AERMOD Version 09292. Inputs to AERMOD include emission source and receptor geographic locations, terrain heights, stack parameters, pollutant emission rates and meteorological data.

2. Modeling Assumptions

   Conservative assumptions were selected to provide an evaluation of maximum potential impacts and demonstrate that the project would not result in an exceedance of an air quality standard. Table 12 below, summarizes the various model options used within AERMOD.

Table 12: Modeling Assumptions

Parameter	Option
Area	Rural
Stack Tip Downwash	On
Elevated Terrain	Terrain and Hill Heights Considered
Plume Depletion	Off
Calms Processing	On
Missing Data Processing	On
Exponential Decay	Off

3. Meteorological Data

   Surface meteorological data was obtained from the National Weather Service for the Casa Grande Airport and upper air data from the Tucson meteorological monitoring station was used to process the data.

4. Receptor Grid

   A receptor grid using Cartesian coordinates based on Universal Transverse Mercator (UTM) coordinates was established using the following approach:
   •Facility boundary was defined using a 50-meter spacing along the property line.
   •Grids were placed starting at the facility boundary in the following manner:
   50-meter grid from the facility to a distance of 250-meters;

100-meter grid from 250 meters out to 1000-meters from the facility boundary;
250-meter grid from 1000-meters to 2500-meters from the facility boundary

5. Background Concentrations

Table 13: Attainment-pollutant Background Concentrations

Pollutant	Averaging Period	Background Concentrations (ppm)[20]	Background Concentrations (μg/m^3)
NO_2[21]	1-Hour	0.057	107.02
	Annual	0.0111	20.84
	3-Hour	0.015	39.22
SO_2[22]	24-Hour	0.007	18.30
	Annual	0.002	5.23
~~PM_{10}~~[~~23~~]	~~24-Hour~~	~~N/A~~	~~146.3~~

C. Significant Impact Analysis

Updated modeling was performed to evaluate whether the impacts would be above the Significant Impact Levels (SILs) for any pollutant and or if any further evaluation is needed. Table 14 summarizes the results of the modeling for criteria pollutants. Notably, for $PM_{2.5}$ and PM_{10}, initially calculated impacts include emissions from the boiler as well as from fugitive emissions (but not the cooling tower).

Table 14: Modeled Impact Analysis[24]

20 Highest background level from the period 2007 through 2009 was used to represent ambient background concentrations.

21 NO2 background concentration was used from the Buckeye monitoring station in Maricopa County.

22 SO2 background concentration was used from the monitoring station in San Manuel, Pinal County.

23 See TSD §7.E.3 for a review of PM10 impacts.

24 6/6/11 - Modeled impacts are all based on a heat input of 402 MMBtu/hr, EXCEPT for the 1-hour NO2 impact, which is based on 410 MMBtu/hr. Confirmed with V.Thompson, 6/3/11. dpg

Pollutants	Averaging Period	Modeled Impact ($\mu g/m^3$)	SIL ($\mu g/m^3$)
CO	8-Hour	31.11	500
	1-Hour	49.04	2,000
NO_2	Annual	1.42	1
	1-Hour	36.78	N/A
	3-Hour	15.35	25
SO_2	24-Hour	11.03	5
	Annual	0.81	1
	3-Hour	16.15	25
PM_{10}	24-Hour	3.68	10
$PM_{2.5}$	24-Hour	4.00	5

The above table indicates that except annual NO_2 and 24-hour SO_2, all the other pollutants are within the Significant Impact Analysis limits for their respective averaging time periods and therefore no further analysis is required.

In addition, Valorie Thompson indicated that on an annual basis, anticipated $PM_{2,5}$ impacts from the boiler would not exceed 0.265 $\mu g/m^3$, and facility-wide annual $PM_{2.5}$ impacts (excluding cooling tower $PM_{2.5}$ impacts) would not exceed 0.533 $\mu g/m^3$.[25]

D. Results

Table 15 summarizes the results of the annual NO_2 and 24-hour SO_2 along with background concentrations in comparison with the NAAQS.

Table 15: Modeled Impact Plus Background Concentrations[26]

25 5/5/2011 email from Valorie Thompson, Scientific Research Associates, to Don Gabrielson, PCAQCD.

26 6/6/11 - Modeled facility impacts are all based on a heat input of 402 MMBtu/hr, EXCEPT for the 1-hour NO2 impact, which is based on 410 MMBtu/hr. Confirmed with T.Thompson, 6/3/11. dpg

Pollutant	Averaging Period	Impact (μg/m^3)	Background Conc. (μg/m^3)	Modeled Impact + Background Conc. (μg/m^3)	NAAQS (μg/m^3)	% NAAQS Impact
NO_2	1-Hour	36.78	107.02	143.8	188	76.5%
	Annual	1.42	20.84	22.26	100	22.3%
SO_2	3-Hour	16.15	39.22	55.37	1,300	4.3%
	24-Hour	11.03	18.30	29.33	365	8.0%
	Annual	0.81	5.23	6.04	80	7.6%
$PM_{10}/PM_{2.5}$	24-Hour	<4.0				

Further analysis for annual NO_2 and 24-hour SO_2 confirm that the air quality standards are not exceeded for these averaging time periods.

E. Nonattainment Analysis

CAA §110.a.2.C requires an approvable State Implementation Plan to include "a program to provide for ... regulation of the modification and construction of any stationary source ... as necessary to assure that national ambient air quality standards are achieved ...."

For a major emitting source (i.e. a PSD-class major source of criteria pollutants) located in an attainment area, an detailed ambient impact analysis is not required if an applicant reasonably demonstrates that anticipated ambient impacts will fall below the EPA's "significant impact levels," or "SILs."[27] Moreover, in an attainment area, the Clean Air Act also required the EPA to promulgate "maximum allowable increases" for the respective criteria pollutants. See 40 CFR §51.166.

For a major emitting source in a nonattainment area (i.e. a source with the capacity to emit 100 TPY or more of a criteria pollutant), the Clean Air Act sidesteps the process of analyzing actual resulting source-specific ambient impacts of the nonattainment pollutant by instead mandating that the source obtain at least 1:1 offsets of the offending pollutant in the vicinity of the new source. See 40 CFR §51.165. That requirement apparently embraces a conclusion that to the extent a source is removing as much annual pollution as it is adding, ambient air quality

27 SILs are "de minimis values ... widely considered to be useful components for implementing the PSD program, they are not absolutely necessary for the states to implement their PSD programs." 75 FR 64863, 64899 (10/20/2010).

probably will not be harmed.

For smaller sources, the EPA's implementing rules provide scant guidance as to how ambient impacts should be managed for sources not covered by the regulations cited above. See 40 CFR §§51.160 - 51.164.

Neither Pinal County nor ADEQ has ever formally adopted rules extending an offset obligation to minor-sources proposing to construct in a nonattainment area.

Accordingly, PCAQCD embraces the following logic to conclude that incremental $PM_{2.5}$ and PM_{10} impacts will not adversely affect ambient air quality.

1. $PM_{2.5}$ 24-hour Impacts

   Incremental 24-hour $PM_{2.5}$ impacts without the cooling tower emissions reach 3.60 μg/m^3, which is more than the EPA's Class II area 24-hour $PM_{2.5}$ SIL of 1.2 μg/m^3.

   That 24-hour $PM_{2.5}$ impact of 3.60 μg/m^3 is less than the EPA's Class II area 24-hour $PM_{2.5}$ increment of 9 μg/m^3.

   And added to the most recent 31 μg/m^3 3-year average for 24-hour $PM_{2.5}$, addition of a facility-specific incremental 24-hour $PM_{2.5}$ impact of 3.60 μg/m^3 still only reaches 34.6 μg/m^3, which is less than the 24-hour $PM_{2.5}$ ambient standard of 35 μg/m^3.

   A supplemental analysis by the applicant indicates that as long as the $PM_{2.5}$ emissions from the cooling tower do not exceed 0.23 lb/hr[28], aggregate $PM_{2.5}$ impacts will still not exceed 4.0 μg/m^3 or produce impacts above the 24-hour $PM_{2.5}$ ambient standard.

2. $PM_{2.5}$ Annual Impacts

   Incremental annual $PM_{2.5}$ impacts, without considering cooling tower emissions, reach about 0.53 μg/m^3.

   As discussed above, the nearby feedlots generate about 1/3 of the nominal 15 μg/m^3 $PM_{2.5}$ impact at the Cowtown monitor.

   Even with the incremental annual impacts from this facility, the regulatory exclusion of the monitor with respect to the annual $PM_{2.5}$ standard will not change because well in excess of 10% of the $PM_{2.5}$ impact at the monitor will

28 Equivalent to cooling tower PM10 emissions of 0.383 lb/hr. Confirmed by V. Thompson, 6/3/11.

still be from the feedlot emissions.

Since 24-hour $PM_{2.5}$ emissions from the cooling tower are small, they have not been further considered.

3. PM_{10} 24-hour Impacts

The incremental 24-hour PM_{10} impact is identical to the $PM_{2.5}$ impact at 3.60 $\mu g/m^3$, which is less than the EPA's 24-hour PM_{10} "de minimis" SIL of 10 $\mu g/m^3$, and is also less than the Class II area PM_{10} 24-hour increment of 30 $\mu g/m^3$.

In relative terms, the projected 3.60 $\mu g/m^3$ impact is small compared to the prevailing 150 $\mu g/m^3$ PM_{10} standard. Given that the form of the current PM_{10} standard is an exceedance-based standard, and that no regulatory or other logically compelling algorithm exists to conveniently translate that incremental ambient impact into a projected change in the anticipated exceedance rate, PCAQCD declines to engage in speculation as to the effect on the anticipated exceedance rate.

Further, in the absence of any regulatory basis to impose an offset requirement; remembering that this area is still formally designated as attainment for PM_{10}; considering the plethora of purely fugitive background sources that are not regulated under a permit program; and recognizing that the only other alternative would be to simply deny this or any other permit that would add PM_{10} impacts in a nonattainment area, PCAQCD finds no regulatory basis to conclude that this facility will cause or contribute to a violation of the PM_{10} standard.

The additional PM_{10} 24-hour impacts from cooling tower are projected 167% of $PM_{2.5}$ impacts, or not more than 0.67 $\mu g/m^3$. That additional impact does not affect the preceding analysis.

8 . CONCLUSION AND PROPOSED ACTION

Based on the information supplied by the applicant, coupled with analyses conducted by the PCAQCD, it is determined that the proposed project will not cause or contribute to a violation of any federal ambient air quality standards. Therefore, PCAQCD intends to issue to the applicant a unitary permit, including both approval to construct/modify pursuant to CAA Title I, and authority to operate, pursuant to CAA Title V, subject to the conditions set forth in the accompanying draft permit.