Section 3

Application Summary

The **Application Summary** shall include a brief description of the facility and its process, the type of permit application, the applicable regulation (i.e. 20.2.72.200.A.X, or 20.2.73 NMAC) under which the application is being submitted, and any air quality permit numbers associated with this site. If this facility is to be collocated with another facility, provide details of the other facility including permit number(s). In case of a revision or modification to a facility, provide the lowest level regulatory citation (i.e. 20.2.72.219.B.1.d NMAC) under which the revision or modification is being requested. Also describe the proposed changes from the original permit, how the proposed modification will effect the facility's operations and emissions, de-bottlenecking impacts, and changes to the facility's major/minor status (both PSD & Title V).

Routine or predictable emissions during Startup, Shutdown, and Maintenance (SSM): Provide an overview of how SSM emissions are accounted for in this application. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.nmenv.state.nm.us/aqb/permit/app_form.html) for more detailed instructions on SSM emissions.

The San Juan Generating Station (SJGS) is a four-unit coal fired electric steam generating facility. Each unit consists of a pulverized coal, wall fired, dry bottom boiler. Foster Wheeler manufactured the unit 1 and 2 boilers and Babcock and Wilcox manufactured the units 3 and 4 boilers. Unit 2 was constructed first, followed by units 1, 3 and 4. The units are numbered from south to north. Unit 1 is the furthest south.

The current coal source for SJGS is the nearby BHP Billiton San Juan Coal Company's San Juan Mine, although the facility has utilized other coal sources in the past and is currently evaluating alternative coal sources for the future. The maximum SJGS annual coal usage (all four units combined) is 8,200,000 tons.

The San Juan Mine delivers coal to SJGS by conveyor. From the main delivery point, SJGS conveyors distribute the coal to the individual units, where it is pulverized and sent to the boilers for combustion. Heat from the combustion process is used to produce superheated steam, which in turn drives steam turbines on each unit. Units 1, 3 and 4 have General Electric turbines and unit 2 has a Westinghouse turbine. The maximum nominal gross generating capacity for each turbine is:

Unit 1: 370 MW
Unit 2: 370 MW
Unit 3: 560 MW
Unit 4: 560 MW

The maximum nominal, gross station-wide electrical production capacity is 1,860 MW. The changes in gross MW hours from previous listed gross generation capacity are due to effects of a turbine re-blading program. This program increased the efficiency of the turbines, but did not increase boiler heat input or increase fuel use, as previously reported.

After the turbines have extracted energy from the steam, the steam is condensed back to liquid phase, using forced draft cooling towers for heat rejection, and recycled back to the boilers.

Raw water used at SJGS is obtained from the San Juan River, approximately 3.5 miles southeast of SJGS. Raw water from the river is pumped to a raw water reservoir near the plant. SJGS includes a complex processing system for boiler water, cooling water and other water treatment to produce water with the

required quality and properties. This water treatment system includes systems for treating and recycling water and for disposal of wastewater streams.

SJGS currently operates under Operating Permit P-062R2 and NSR Permit 0063-M7. Operating Permit P062R2 was issued on January 24, 2011 and NSR permit 0063-M7 was issued on December 14, 2011.

This permit application has two distinct permitting scenarios that are mutually exclusive, i.e., if one scenario becomes final the other scenario becomes moot. Scenario A is the permitting scenario required to implement the SJGS Federal Implementation Plan (FIP) published in 40 CFR 52.1628 (August 22, 2011). The provisions of this FIP are under judicial review, but the FIP implementation date makes it necessary to proceed with obtaining the authority-to-construct air permit immediately to insure construction of the required equipment (SCR) can begin in time to meet the FIP operational deadline. Scenario B of this permit application is intended to implement the requirements of the State of New Mexico Regional Haze State Implementation Plan, (SIP) adopted pursuant to 40 CFR 51.309, which specifies controls for SJGS that are different than the FIP. If the judicial review of the FIP results in vacatur of the FIP requirements, PNM would implement the SIP requirements which require installation and operation of an SNCR control system, rather than SCR. SNCR is represented in this permit application as Scenario B. While permitting scenarios A and B are distinct, this application includes permit modifications that are common to both scenarios. The permitting description given below, therefore, list the permitting elements as "Common", "Scenario A" only and "Scenario B" only.

This application includes the following permitting changes/updates to Scenario A only:

1-A: The SCR system will consist of the addition of a catalyst bed on the flue gas exhaust of each unit. The SCR will be installed downstream of the boiler economizer and upstream of the baghouse on each unit. The ESP structure will likely remain intact, but the flue gases will no longer flow through the de-energized ESP. New duct work will by-pass the ESP structure.

2-A: The SCR will use anhydrous ammonia. Anhydrous ammonia will be delivered by truck. Truck traffic for the ammonia delivery have been added to the truck traffic paved road vehicle travel estimates for calculation of fugitive dust from vehicle traffic on paved roads. Ammonia "slip" emissions from the boiler stacks have been calculated based on a maximum slip of 2 ppm. The anhydrous ammonia delivery and storage system is a pressurized sealed system that will not be a source of routine ammonia emissions.

3-A Addition of a dry sorbent injection (DSI) system for potential control of SO_3/H_2SO4 emissions. Emission sources associated with the sorbent injection system are fugitive road dust emissions (on paved roads) from truck delivery of the sorbent material and unloading the sorbent material to storage silos. Three new silos (one for units 1/2 and one each for units 3 and 4) will be added for sorbent storage. Pneumatic air used for silo loading is vented from each silo through a fabric filter baghouse.

4-A: New boiler stack emission limits for NOx emissions (0.05 lb/mmBtu 30-boiler operating day rolling average) and H_2SO4 (2.6×10^{-4} lbs/mmBtu) are required by the Federal Implementation Plan applicable to SJGS and H_2SO4 (lbs/mmBtu) are required by the Federal Implementation Plan applicable to SJGS. The FIP also requires that the SCR system be designed to limit ammonia slip to 2 ppm.

5-A: The fly ash handling system will be modified by the addition of ash hoppers at the boiler economizer outlets to remove ash that gravitationally settles in this section of the exhaust duct work. This ash will be combined with the boiler bottom ash which is handled wet and is not an emission source. An ash collection hopper will be installed to collect ash from the SCR catalyst inlet. The ash collection hoppers on the ESPs will no longer collect ash, as the ESP structures will be bypassed. These changes in the fly ash collection points do not change the overall quantity of ash produced or handled and do not affect air emissions from fly ash handling.

This application includes the following permitting changes/updates to Scenario B only:

1-B: The SNCR system will use urea (50% solution in water) as the source of ammonia for reaction with and reduction of NOx emissions. The urea solution will be injected directly into the flue gas within the boilers on each unit.

2-B: Urea solution will be delivered to the site by tanker truck. Truck traffic for the urea delivery has been added to the truck traffic paved road vehicle travel estimates for calculation of fugitive dust from vehicle traffic. The urea solution will be stored on-site in liquid storage tanks prior to use. These tanks will not be an air emissions source. Ammonia "slip" emissions from the boiler stacks have been calculated based on a maximum slip of 10 ppm.

3-B: For Scenario B, the de-energized ESP structures will not be bypassed and the current ash removal system at the ESP hoppers, which removes fly ash that gravitationally settles in the de-energized ESPs will remain in place.

4-B: A new boiler stack emission limit for NOx (0.23 lbs/mmBtu 30 day rolling average) required by the State Implementation Plan applicable to SJGS, and ammonia slip (10 ppm) will be added for each boiler unit

Common Permit Elements

This application includes the following permitting changes/updates common to both Scenarios A and B.:

1. Unit production maximum output capacity, in terms of maximum gross megawatts of potential power generation, have been updated to reflect upgrades to the steam turbines through a turbine re-blading project. The Department was notified of the turbine re-blade project in July 2008. While the turbine re-blading changes the maximum electrical output through improvement of turbine efficiency, there is no change to unit heat input or fuel.

2. Both scenarios include modifications to the fan system to achieve "balanced" draft configuration allowing for the elimination of emission units E501, E502, E503 and E504.

3. The calculation methodology for PM emissions from the cooling towers (from TDS in the cooling tower drift) has been updated. The previous methodology assumed that PM10 and PM2.5 were equal to TSP. This assumption overestimates the PM10 emissions and greatly overestimates PM2.5. More modern calculation methods, which have been routinely used for more recent permitting actions, have been applied to provide more realistic emission estimates. In addition, the TDS values for the circulating water have been adjusted to better match

operating requirements. The TDS for Units E406, E407 and E409 have been changed from 5,500 mg/l TDS to 6,000 mg/l TDS and Units E408 and E410 have been changed from 4,500 mg/l to 3,900 mg/l. Overall PM emissions in the cooling tower drift remain essentially unchanged.

4. In addition to Scenario A and B specific changes/additions to vehicle traffic at the site, the overall site vehicle fleet composition and vehicle mileage (VMT) have been updated for calculation of fugitive road dust emissions from both paved and unpaved roads. Emission units E704A (front end loader travel at coal piles) and E707 (front end loader travel at gypsum piles) were previously listed as separate emission units. These have been consolidated into the Unpaved Vehicle Travel emission unit.

5. In some instances previous calculations and calculation results for unchanged emission units were updated to be consistent with current NMED guidance on significant figures.

Section 4

Process Flow Sheet

A **process flow sheet** and/or block diagram indicating the individual equipment, all emission points and types of control applied to those points. The unit numbering system should be consistent throughout this application.

The following process block-flow diagrams identify all regulated emission sources. Insignificant or exempt emission sources are not shown. Only processes directly related to the regulated emission sources are shown on these diagrams.

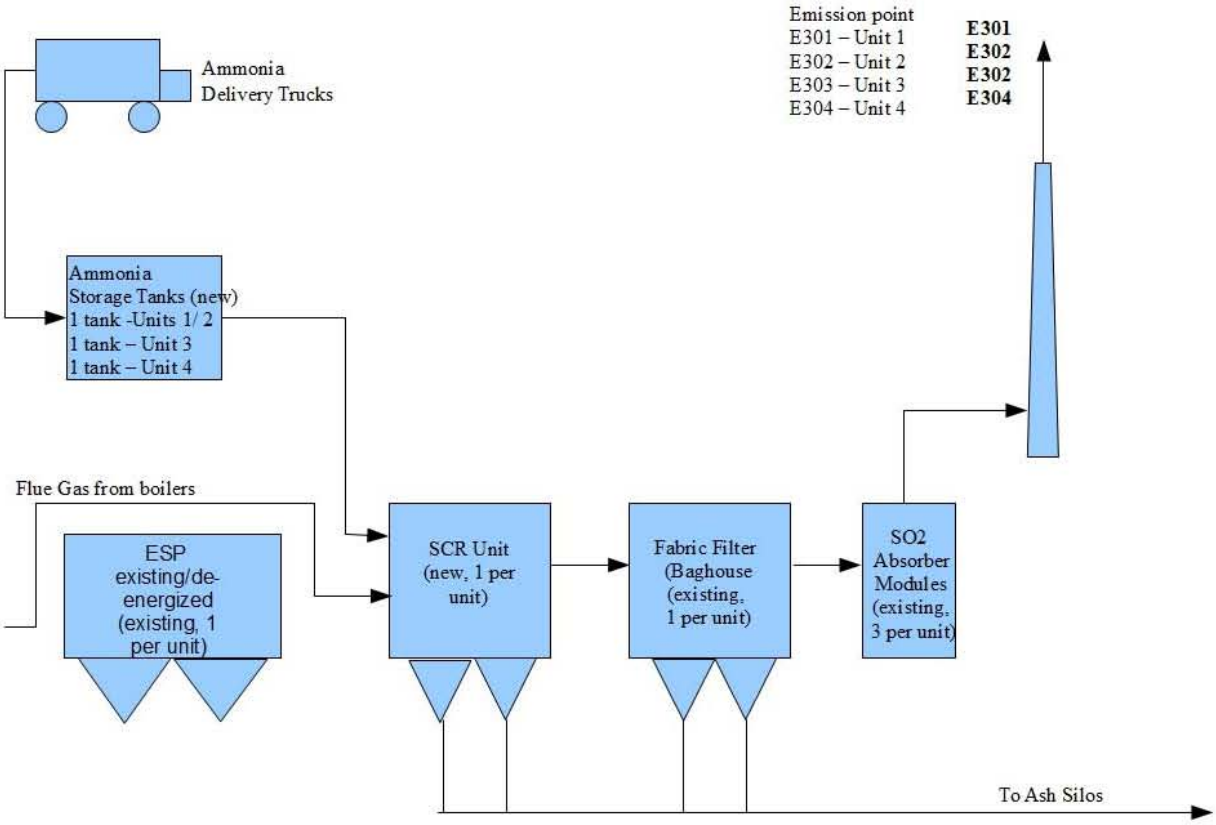


Figure 1: Flue Gas Stream - Selective Catalytic Reduction (SCR) Scenario A

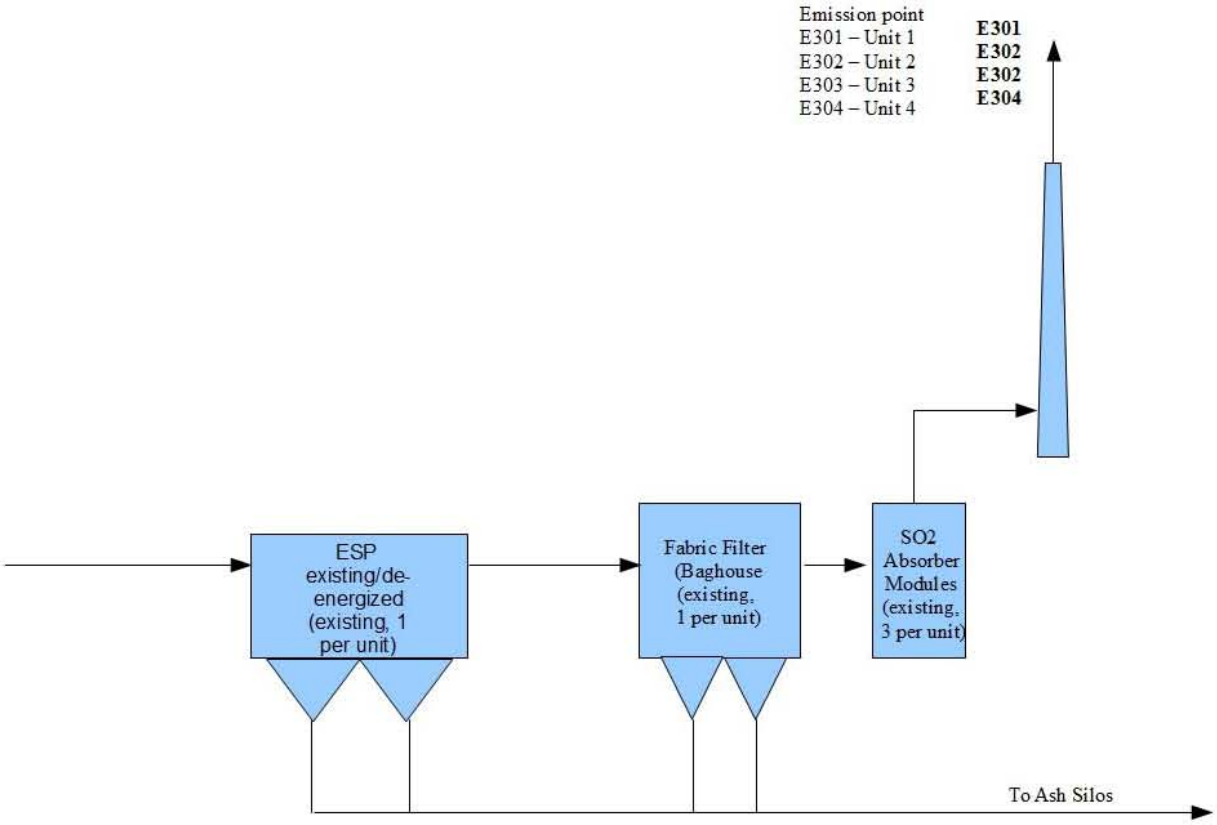


Figure 2: Flue Gas Stream - Selective Non-Catalytic Reduction (SNCR) Scenario B)

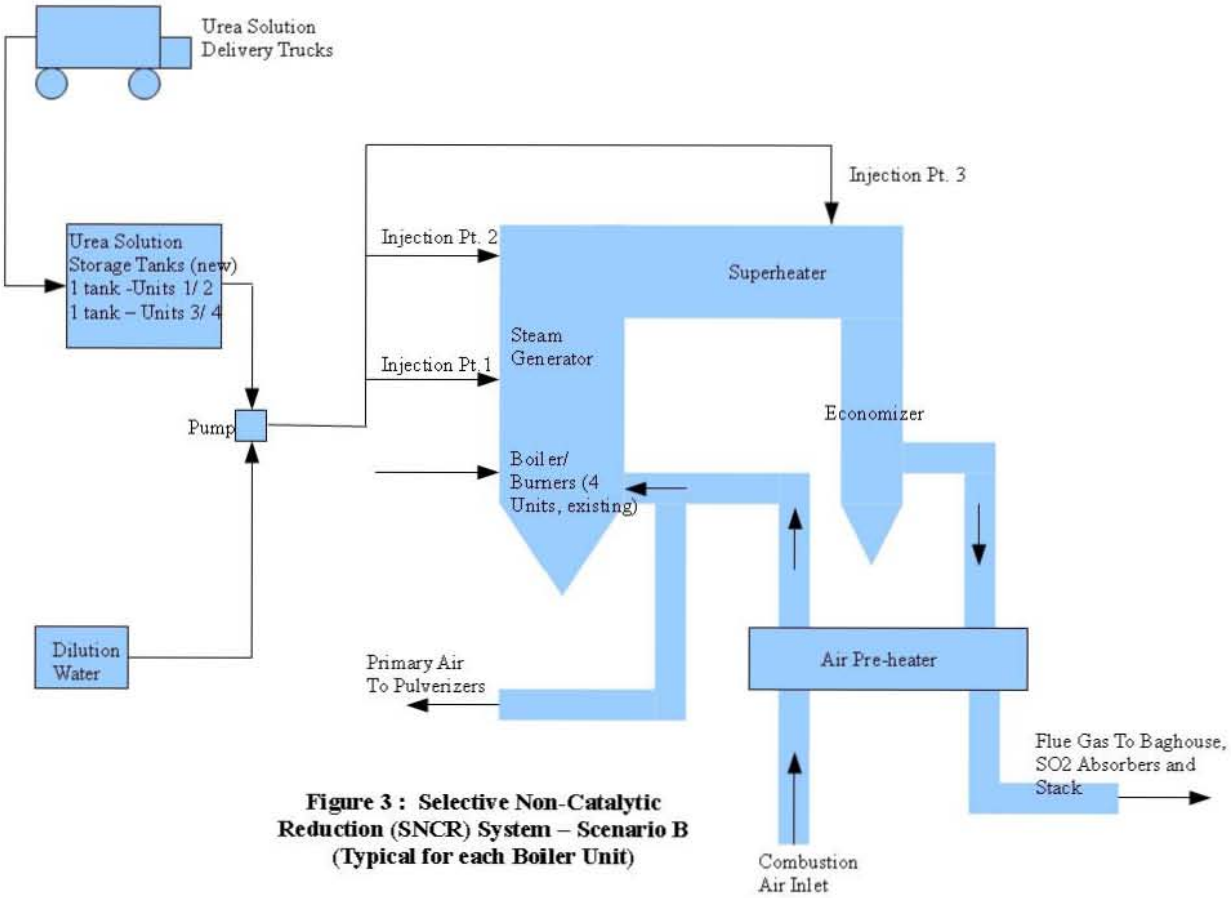


Figure 3 : Selective Non-Catalytic Reduction (SNCR) System – Scenario B (Typical for each Boiler Unit)

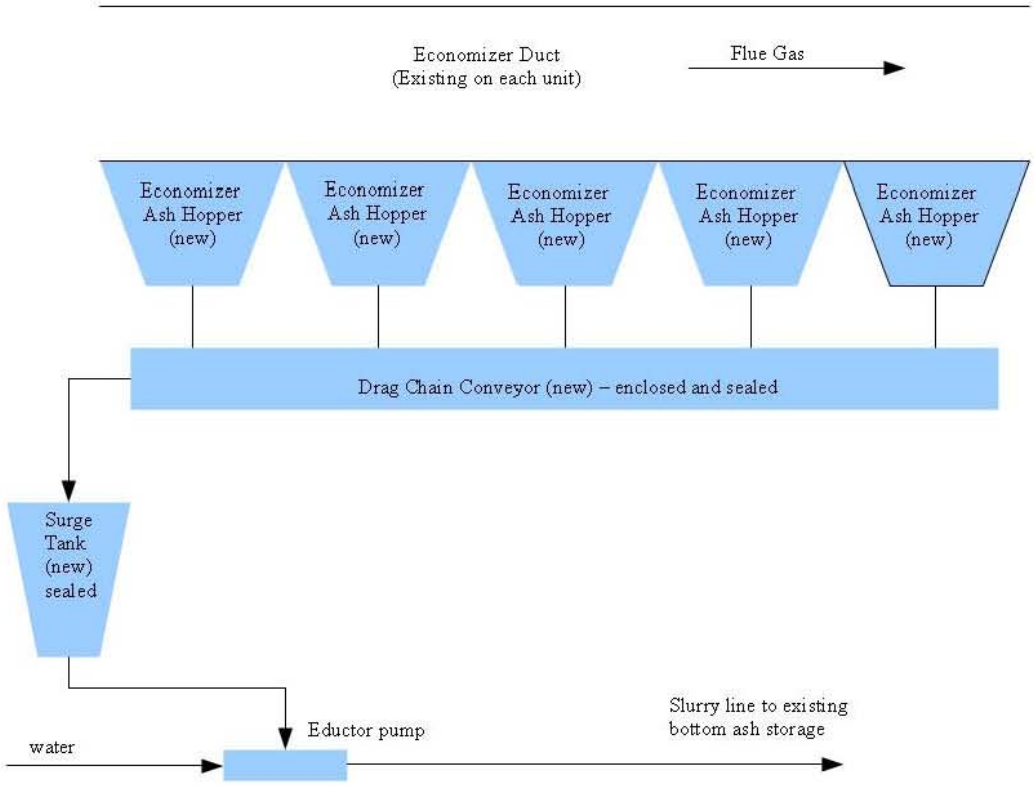


Figure 4: New ash hoppers on economizer outlet (typical for each boiler unit) (system is sealed, discharge is a slurry – no new air emission sources) – Senario A only

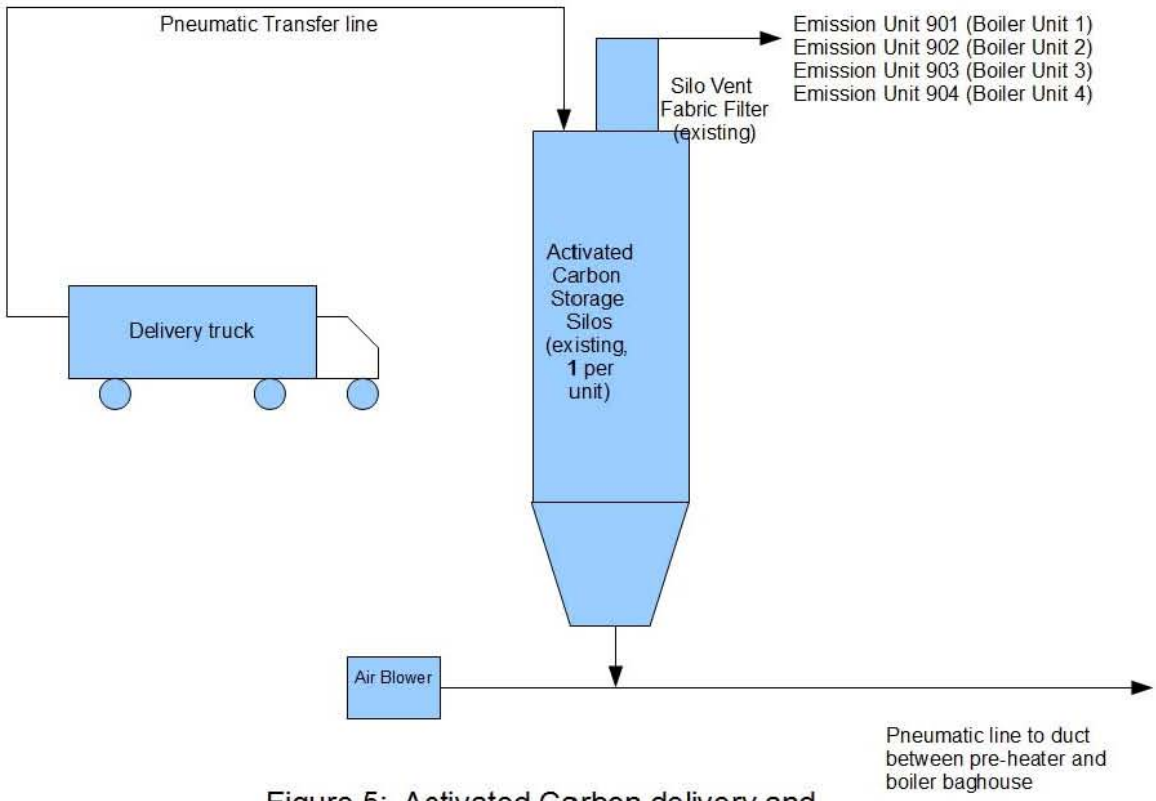


Figure 5: Activated Carbon delivery and storage system (typical for each boiler unit)

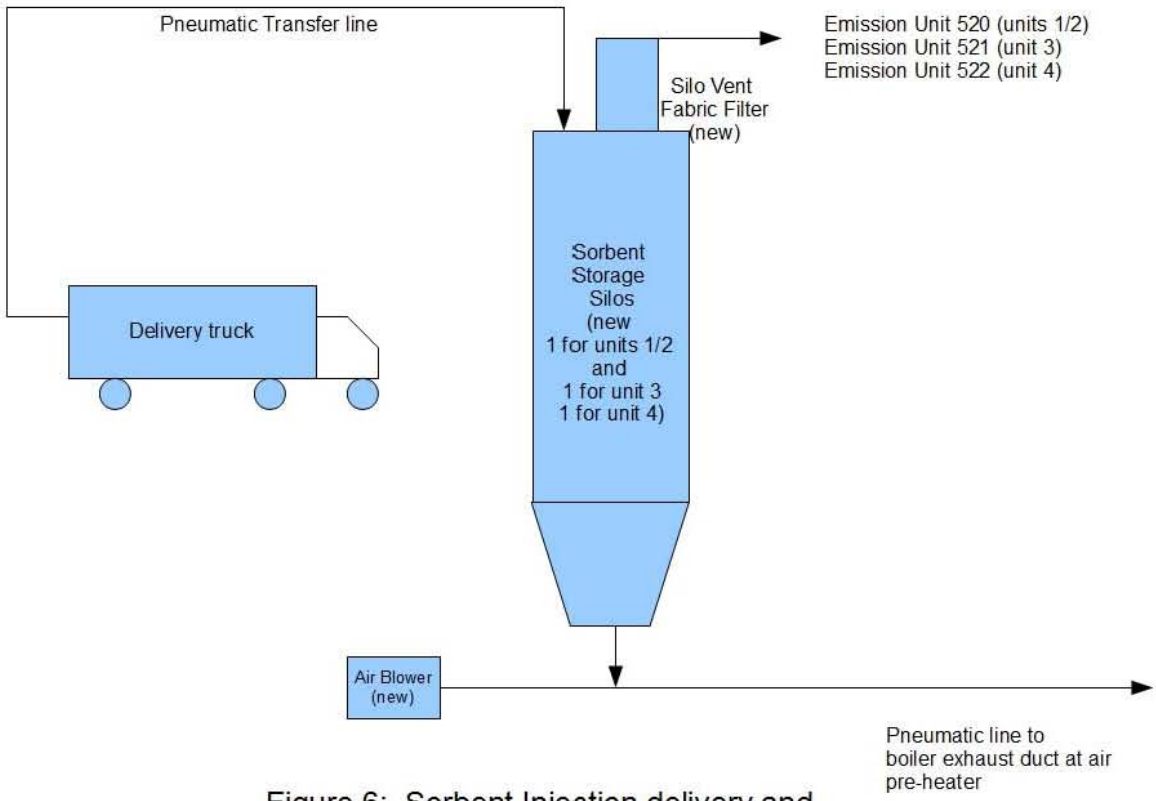


Figure 6: Sorbent Injection delivery and storage system – Scenario A only

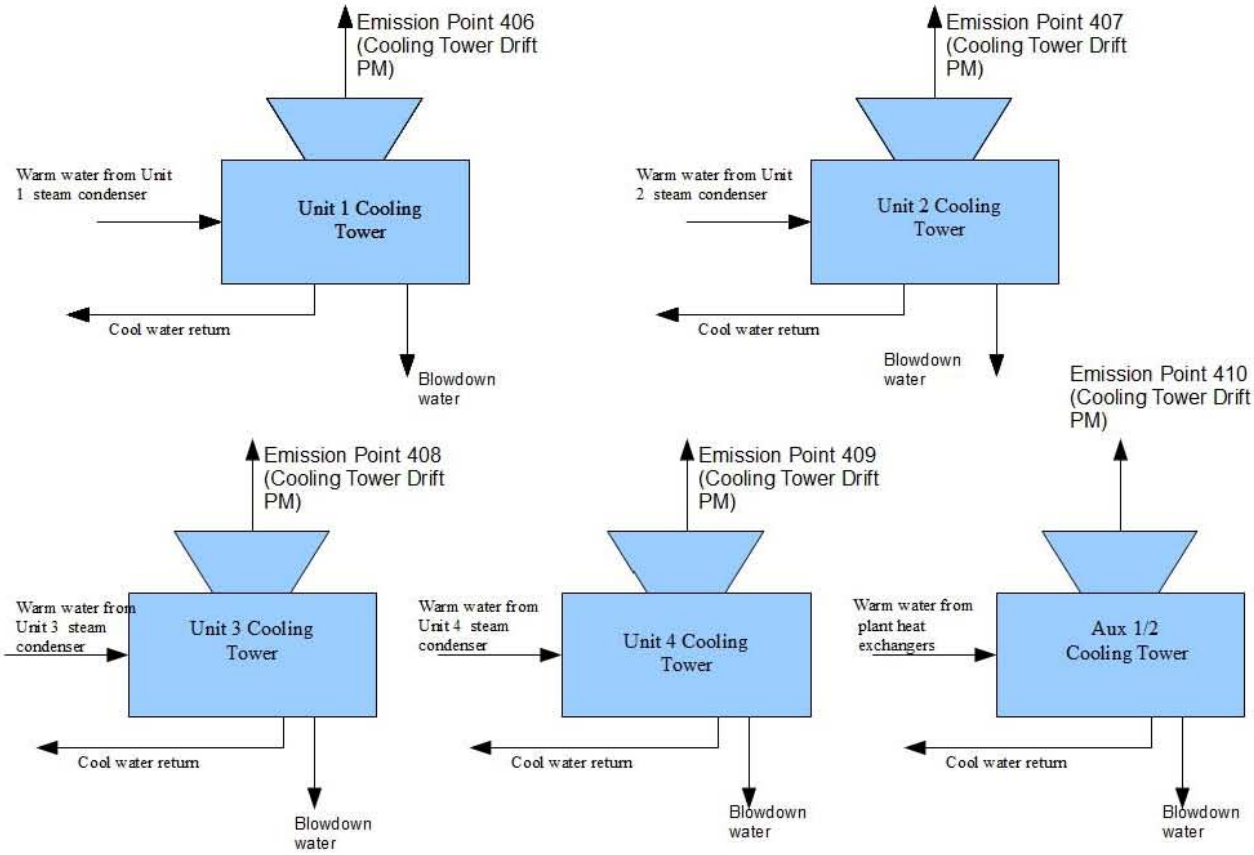


Figure 7: Cooling Towers (existing)

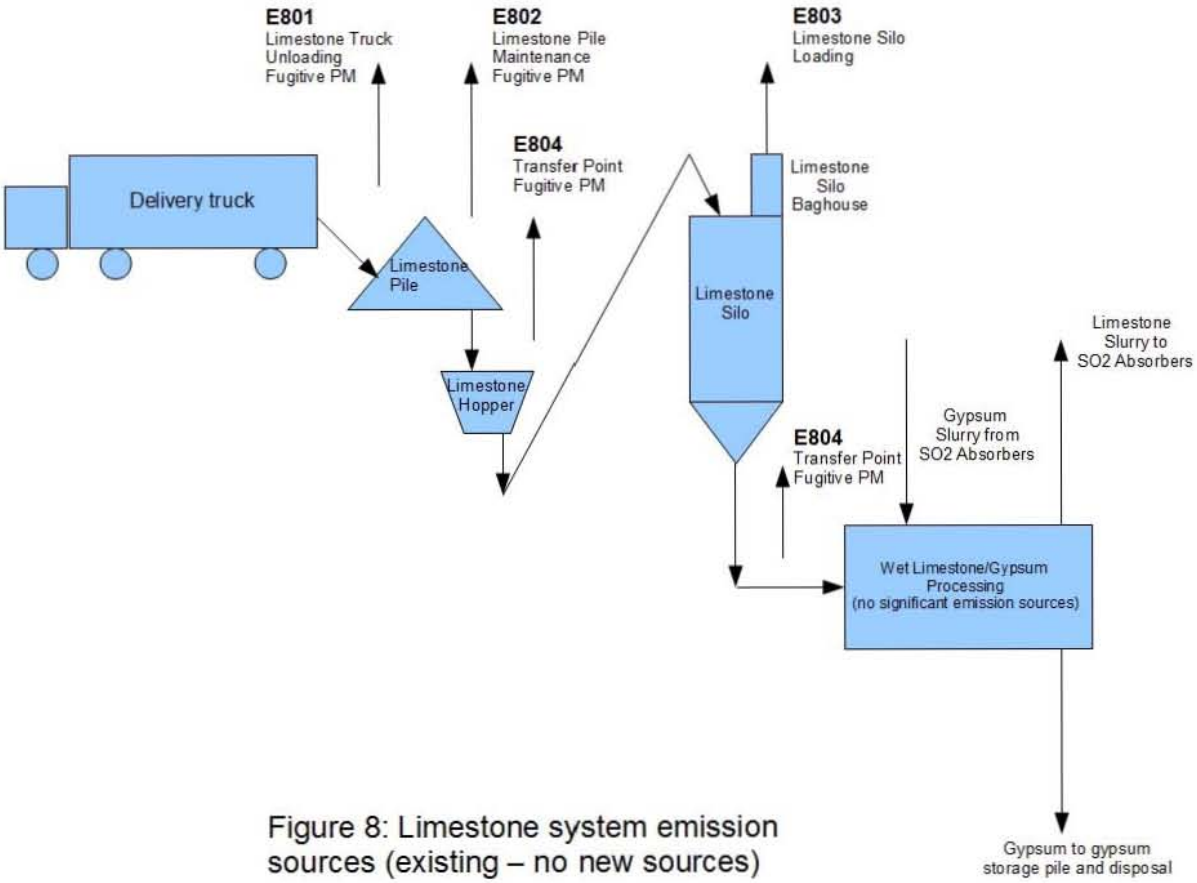


Figure 8: Limestone system emission sources (existing – no new sources)

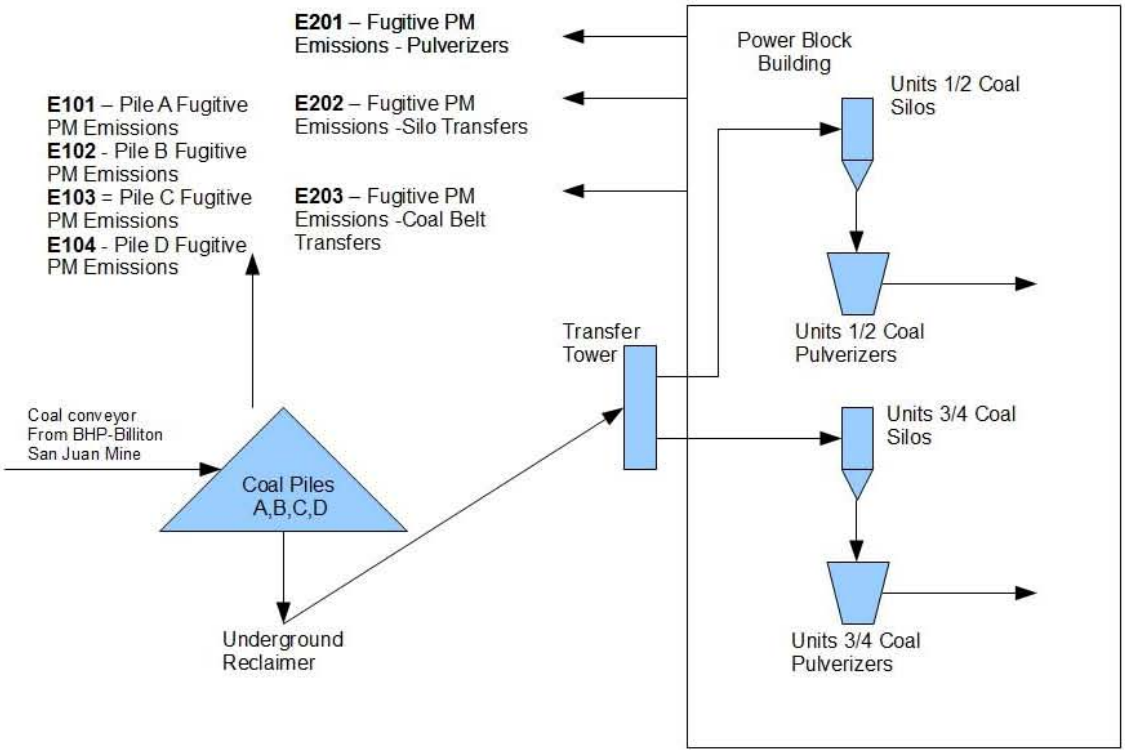
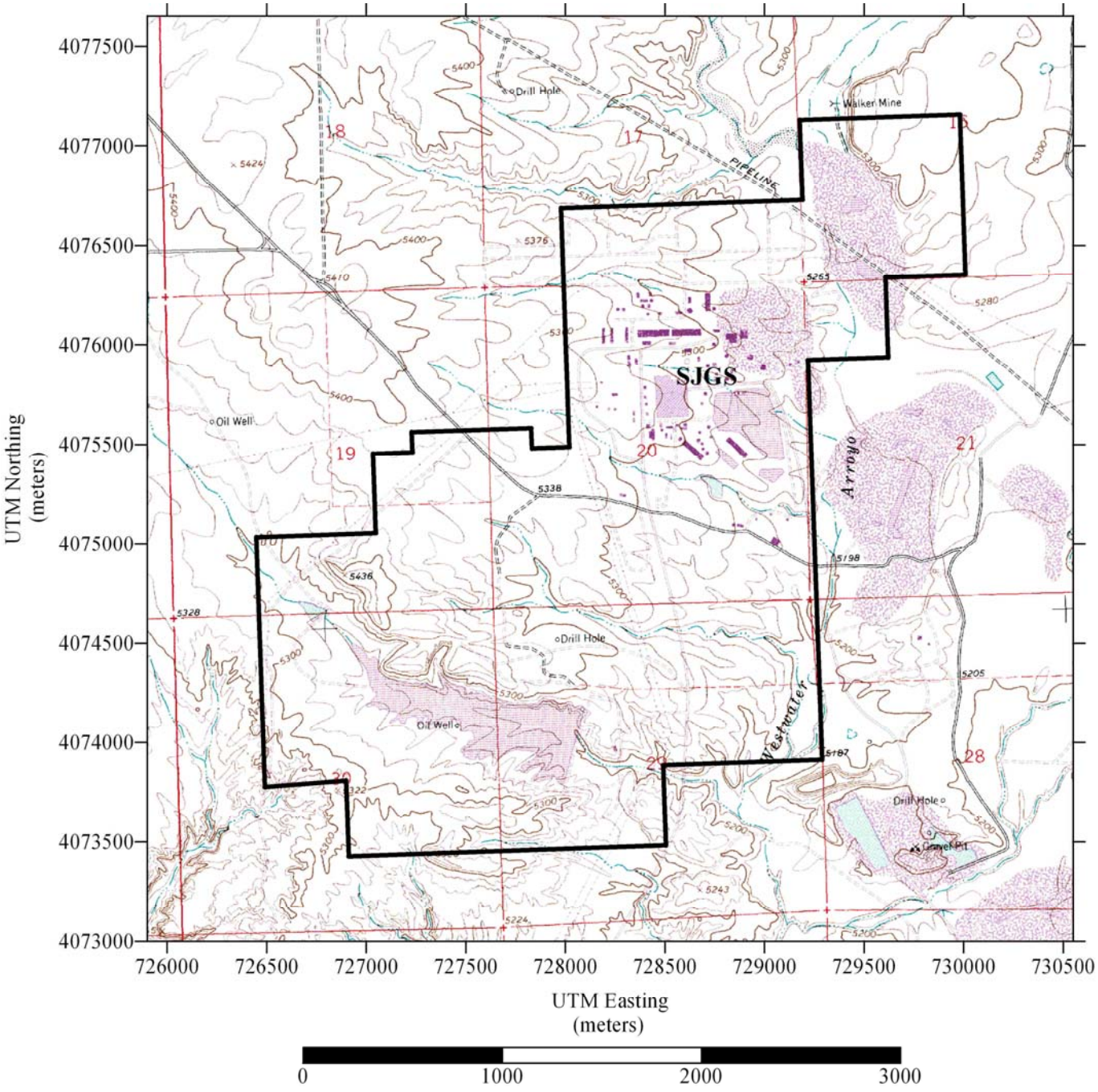


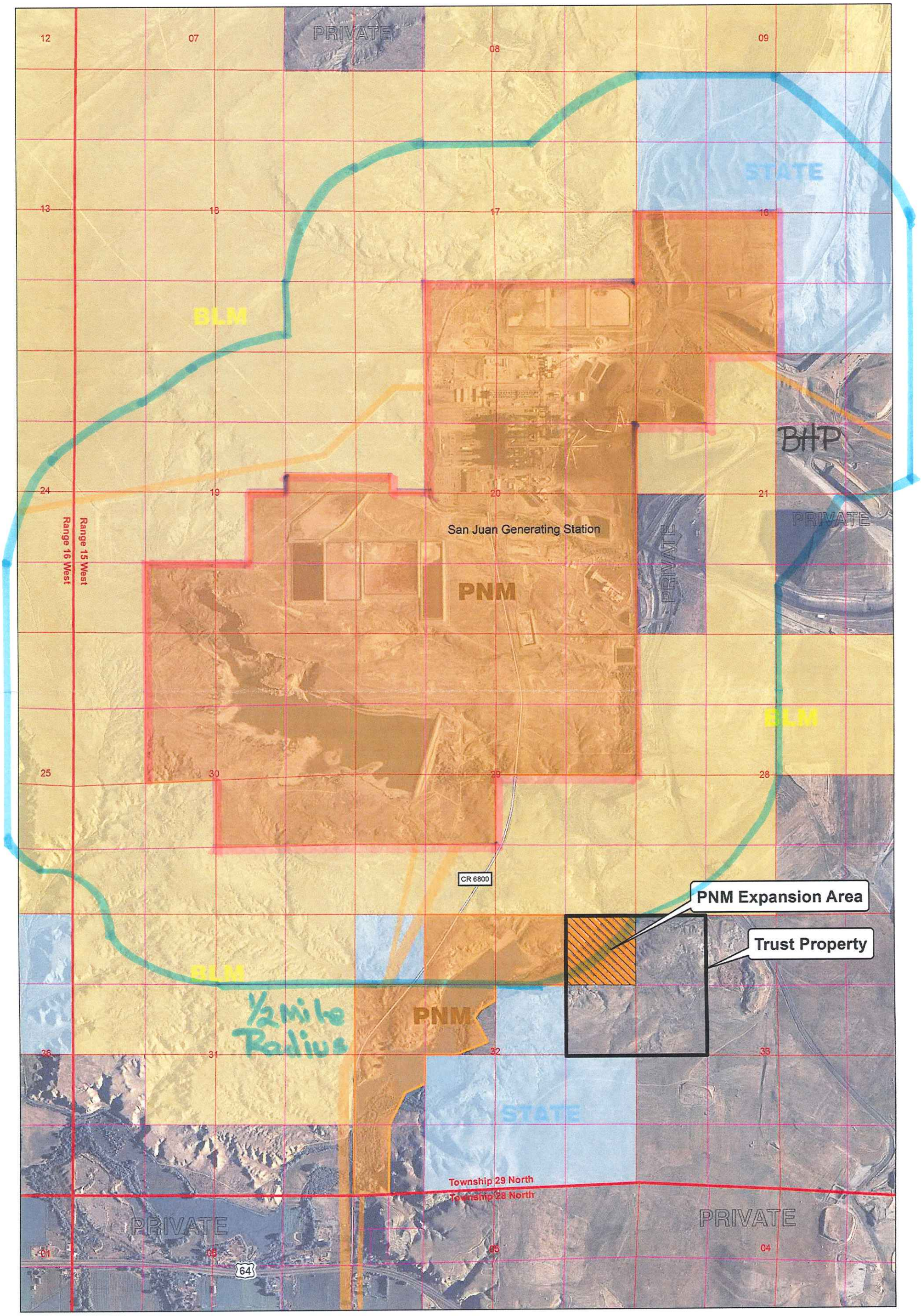
Figure 9: Coal Handling system emission sources (existing – no new sources)

Section 5

Plot Plan Drawn To Scale

A **plot plan drawn to scale** showing emissions points, roads, structures, tanks, and fences of property owned, leased, or under direct control of the applicant. This plot plan must clearly designate the restricted area as defined in UA1, Section 1-D.12. The unit numbering system should be consistent throughout this application.





San Juan Generating Station
Land Ownership Map

Ownership data from New Mexico Office BLM January 2010
Aerial Photography from USGS 2005

Map Created by PNM, June 28, 2010. Revised August 16, 2011

Proprietary Statement
This document and all previous issues are the property of Public Service Company of New Mexico (PNM) and neither receipt nor possession thereof vests or transfers any right to or license to use this document, the subject matter thereof, or any design or technical information shown thereon, or any right to reproduce this document, or any part thereof. Neither this document nor any information contained herein may be copied, reproduced, or otherwise used or disclosed to any other party without first obtaining the express written permission of PNM. This document is provided under the express condition that it will be held in confidence by the recipient, that it is subject to return upon demand, and that it will not be used in any way detrimental to PNM.

0 400 800
Feet

PNM

Section 6

All Calculations

Show all calculations used to determine both the hourly and annual controlled and uncontrolled emission rates. All calculations shall be performed keeping a minimum of three significant figures. Document the source of each emission factor used (if an emission rate is carried forward and not revised, then a statement to that effect is required). If identical units are being permitted and will be subject to the same operating conditions, submit calculations for only one unit and a note specifying what other units to which the calculations apply. All formulas and calculations used to calculate emissions must be submitted. The "Calculations" tab in the UA2 has been provided to allow calculations to be linked to the emissions tables. Add additional "Calc" tabs as needed. If the UA2 or other spread sheets are used, all calculation spread sheet(s) shall be submitted electronically in Microsoft Excel compatible format so that formulas and input values can be checked. Format all spread sheets and calculations such that the reviewer can follow the logic and verify the input values. Define all variables. If calculation spread sheets are not used, provide the original formulas with defined variables. Additionally, provide subsequent formulas showing the input values for each variable in the formula. All calculations, including those calculations are imbedded in the Calc tab of the UA2 portion of the application, the printed Calc tab(s), should be submitted under this section.

Tank Flashing Calculations: The information provided to the AQB shall include a discussion of the method used to estimate tank-flashing emissions, relative thresholds (i.e., NOI, permit, or major source (NSPS, PSD or Title V)), accuracy of the model, the input and output from simulation models and software, all calculations, documentation of any assumptions used, descriptions of sampling methods and conditions, copies of any lab sample analysis. If Hysis is used, all relevant input parameters shall be reported, including separator pressure, gas throughput, and all other relevant parameters necessary for flashing calculation.

SSM Calculations: It is the applicant's responsibility to provide an estimate of SSM emissions or to provide justification for not doing so. In this Section, provide emissions calculations for Startup, Shutdown, and Routine Maintenance (SSM) emissions listed in the Section 2 SSM and/or Section 22 GHG Tables and the rational for why the others are reported as zero (or left blank in the SSM/GHG Tables). Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.nmenv.state.nm.us/aqb/permit/app_form.html) for more detailed instructions on calculating SSM emissions. If SSM emissions are greater than those reported in the Section 2, Requested Allowables Table, modeling may be required to ensure compliance with the standards whether the application is NSR or Title V. Refer to the Modeling Section of this application for more guidance on modeling requirements.

Glycol Dehydrator Calculations: The information provided to the AQB shall include the manufacturer's maximum design recirculation rate for the glycol pump. If GRI-Glycalc is used, the full input summary report shall be included as well as a copy of the gas analysis that was used.

Road Calculations: Calculate fugitive particulate emissions and enter haul road fugitives in Tables 2-A, 2-D and 2-E for:

1. If you transport raw material, process material and/or product into or out of or within the facility and have PER emissions greater than 0.5 tpy.
2. If you transport raw material, process material and/or product into or out of the facility more frequently than one round trip per day.

Significant Figures:

A. All emissions standards are deemed to have at least two significant figures, but not more than three significant figures.

B. At least 5 significant figures shall be retained in all intermediate calculations.

C. In calculating emissions to determine compliance with an emission standard, the following rounding off procedures shall be used:

(1) If the first digit to be discarded is less than the number 5, the last digit retained shall not be changed;

(2) If the first digit discarded is greater than the number 5, or if it is the number 5 followed by at least one digit other than the number zero, the last figure retained shall be increased by one unit; **and**

(3) If the first digit discarded is exactly the number 5, followed only by zeros, the last digit retained shall be rounded upward if it is an odd number, but no adjustment shall be made if it is an even number.

(4) The final result of the calculation shall be expressed in the units of the standard.

E101-E104 COAL HANDLING OPERATIONS

Emission Estimation Method for PM15 – taken to represent PM10: AP42 11.9
E (lbs/yr) =k(18.6)*$s^{1.5}/M^{1.4}$*#hrs/yr
k = 0.75 (PM10/PM15 constant)
s = 4.80 (%silt content of coal per AP-42 Section 13.2.2. Table 13.2.2-1, Coal fired power plant)
M = 8.74 (% moisture content of coal pile per laboratory testing)
#hrs/yr = 1840 hrs (dozer operation total for 4 piles, 460 hours each)

Emission Estimation Method for TSP: AP42 11.9
E (lbs/yr) =78.4 $s^{1.2}/M^{1.3}$*#hrs/yr
s = 4.80 (%silt content of coal per AP-42 Section 13.2.2. Table 13.2.2-1, Coal fired power plant)
M = 8.74 (% moisture content of coal pile per laboratory testing)
#hrs/yr = 1820 hrs (total dozer operation, 460 hours each)

Emission Point E101, Source S111 – Coal Pile "A" Maintenance

E PM10 (lbs/yr) = 0.75(18.6)*$s^{1.5}/8.74^{1.4}$*460
= 3,209 lbs PM10/yr uncontrolled = 0.36632 lbs/hr (based on 8760 hrs/yr)
= 1.6045 tons PM10/yr uncontrolled

E TSP (lbs/yr) =460* 78.4* $4.8^{1.2}/8.74^{1.3}$*#hrs/yr
= 13,991 lbs TSP/yr uncontrolled=1.5971 lbs/hr (based on 8760 hrs/yr)
= 6.9955 tons TSP/yr uncontrolled

E PM2.5 = 0.022 * 1.5971 lbs/hr TSP = 0.035136 lbs/hr PM2.5 = 0.15390 tpy PM2.5
=

There are no controls so controlled and uncontrolled emissions are equal.

This same calculation procedure applied to Coal Piles "B", "C" and "D" maintenance gives:

Emission Point E102, Source S112 – Coal Pile "B" Maintenance

Controlled Emissions

PM10 = 3,209 lbs/yr = 0.36632 lbs/hr = 1.6045 tpy

TSP = 13,991 lbs/yr = 1.5971 lbs/hr = 6.9955 tpy

PM2.5 = 0.035136 lbs/hr PM2.5 = 0.15390 tpy

Emission Point E103, Source S113 – Coal Pile "C" Maintenance

PM10 = 3,209 lbs/yr = 0.36632 lbs/hr = 1.6045 tpy

TSP = 13,991 lbs/yr = 1.5971 lbs/hr = 6.9955 tpy

PM2.5 = 0.035136 lbs/hr PM2.5 = 0.15390 tpy

Emission Point E104, Source S114 – Coal Pile "D" Maintenance

PM10 = 3,209 lbs/yr = 0.36632 lbs/hr = 1.6045 tpy

TSP = 13,991 lbs/yr = 1.5971 lbs/hr = 6.9955 tpy

PM2.5 = 0.035136 lbs/hr PM2.5 = 0.15390 tpy

COAL PULVERIZERS

Emission Point E201, Source S204 – Coal Pulverizers

Emission Estimation Method: AP42 11.19.2, Table 11.19.2-2, 8/04 (SCC 3-05-020-05, Fines Screening, uncontrolled)

E PM10 = 0.015 lbs/ton
E TotalPM = 0.039 lbs/ton

Total tons of coal = 8,200,000 tpy

E PM10 = 0.015 lbs/ton * 8,200,000 tpy = 123,000 lbs/yr = 14.041 lbs/hr (at 8760 hrs/yr) = 61.4996 tpy

E Total PM = 0.039 lbs/ton * 8,200,000 tpy = 319,800 lbs/yr = 36.507 lbs/hr (at 8760 hrs/yr) = 159.90 tpy

AP42 11.19.2 does not have an emission factor for uncontrolled PM2.5. It does however have emission factors for controlled PM2.5. The ratio of controlled PM10 to PM2.5 emission factors is 0.012/0.0007 = 0.0058333. Assuming this ratio is also applicable to uncontrolled emissions, the uncontrolled PM2.5 is:

E PM2.5 = 0.005833 * 14.041 = 0.08190 lbs/hr = 0.35873 tpy

Control: Use 80% for the pulverizers being inside a building

E PM10 (controlled) = 14.041 * 0.2 = 2.80 lbs/hr = 12.3 tpy

E TotalPM (controlled) = 36.507 * 0.2 = 7.3 lbs/hr = 31.98 tpy

E PM2.5 (controlled) = 0.08190 lbs/hr * 0.2 = 0.01638 lbs/hr = 0.071744 tpy

Emission Point E202, Source S201 – Coal Silos to Coal Belt Feeders

Emission Estimation Method AP42 13.2.4 Drop Operation

$E = k\ (0.00032)\ ((U/5)^{1.3})/(M/2)^{1.4})$ lbs/ton

Where k = 0.35 for PM10 and 0.74 for TSP
U = 10.1 mph

M = 8.72%

E TSP = 0.74 (0.0032) $((10.1/5)^{1.3})/(8.72/2)^{1.4})$ * 8,200,000 tpy = 6,165 lbs/yr = 0.71 lbs/hr = 3.1 tpy

E PM10 = 0.35 (0.0032) $((10.1/5)^{1.3})/(8.72/2)^{1.4})$ * 8,200,000 tpy = 2,916 lbs/yr = 0.34 lbs/hr = 1.5 tpy

E PM2.5 = 0.053 (0.0032) $((10.1/5)^{1.3})/(8.72/2)^{1.4})$ * 8,200,000 tpy = 441.57 lbs/yr = 0.50407 lbs/hr = 0.22078 tpy

Emission Point E203, Source S203 – Coal Belt to Pulverizers Transfer Points

Emission Estimation Method AP42 13.2.4 Drop Operation

E = k (0.0032) $((U/5)^{1.3})/(M/2)^{1.4})$ lbs/ton

Where k = 0.35 for PM10 and 0.74 for TSP
U = 10.1 mph
M = 8.72%

E_{TSP} = 0.74 (0.0032) $((10.1/5)^{1.3})/(8.72/2)^{1.4})$ * 8,200,000 tpy = 6,165 lbs/yr = 0.71 lbs/hr = 3.1 tpy

E_{PM10} = 0.35 (0.0032) $((10.1/5)^{1.3})/(8.72/2)^{1.4})$ * 8,200,000 tpy = 2,916 lbs/yr = 0.34 lbs/hr = 1.5 tpy

E PM2.5 = 0.053 (0.0032) $((10.1/5)^{1.3})/(8.72/2)^{1.4})$ * 8,200,000 tpy = 441.57 lbs/yr = 0.50407 lbs/hr = 0.22078 tpy

COAL BOILER EMISSIONS

Previously existing applicable requirements and emission limits are listed for each pollutant. This application adds new emission limits for NOx and sulfuric acid mist. These limits are prescribed by the FIP (Scenario A). For Scenario B (SNCR) prescribed by the SIP new emission limits are added for NOx. The calculations below represent the facility's potential to emit under applicable requirements; actual emissions from the facility will be lower for most pollutants.

Emission Points 301 -304 Coal Boiler/Boiler Stacks Units 1 - 4

SO_2

Uncontrolled SO_2 emissions are estimated by assuming all sulfur in the coal is converted to SO_2. No adjustments have been made for the sulfur that is retained in the ash.

Maximum short-term uncontrolled SO_2 emissions are based on low Btu coal (9,148 Btu/lb) and maximum sulfur content (0.89%). Annual uncontrolled emissions based on average coal (9,990 Btu/lb and 0.89% S). This should be a conservative value for annual coal as the annual average sulfur content should be less than 0.89%.
Coal use in tph is as follows:

Coal use (tph)		
Unit	Annual Average	Hourly Max
1	185.5	202.6
2	184.6	201.6
3	288.2	314.7
4	282.7	308.7

Calculating SO_2 emissions by SO_2 (lbs/hr) = coal use (tons/hr) * 2000 lbs/ton * 0.0089 lbs S/lb coal * 2 lbs SO_2/lb S results in the following potential to emit (PTE).

Uncontrolled SO_2 Emissions			
Unit	SO_2 (lbs/hr) max	SO_2 (lbs/hr) avg	SO_2 (tpy)
1	7,211.3	6,603.8	28,925
2	7,176.4	6,571.8	28,784
3	11,203.8	10,259.9	44,938
4	10,990.0	10,064.1	44,081

The following limits apply:

Plant-wide: 0.46 lbs/mmBtu annual (NSR/Operating Permit)
Plant-wide: 13,000 lbs/hr 3-hr average (20.2.31NMAC, NSR/Operating Permit)
Plant-wide: 0.55 lbs/mmBtu 30-day average (20.2.31NMAC)
Unit 2: 72% Control 30-day avg (NSR/Operating Permit, 20.2.34NMAC)
Units 1,3,4: 1.2 lbs/mmBtu 3-hr avg (NSR/Operating Permit/40CFR60.4e4(a))
Units 1,2,3,4: 90% control annual average (CD 9cii)
Units 1,2,3,4: 0.25 lbs/mmBtu 7-day average (CD 9cii)
Units 1,2,3,4: tpy limits from Operating Permit (7045.8, 7099.5, 10,944.4, 10736.9 tpy respectively)
Units 1,2,3,4: 0.15 lbs/mmBtu voluntary limit incorporated into Permit 0063M6R2 and tpy rates equivalent to the 0.015 lbs/mmBtu limit. This limit will also become a requirement per the SJGS FIP (40CFR52) when the FIP becomes effective, 5 years after the effective date of the rule.

For calculation involving lbs/mmBtu, the following maximum heat input values are used:
Unit 1: 3,707 mmBtu/hr
Unit 2: 3,688 mmBtu/hr
Unit 3: 5,758 mmBtu/hr
Unit 4: 5,649 mmBtu/hr

E 301 : Unit 1 Boiler Unit Specific Limits

NSPS based limits:

1.2 lbs/mmBtu * 3,707 mmBtu/hr = 4448.4 lbs/hr (3-hr avg) = 19,484 tpy

Consent Decree based limits:

0.25 lbs/mmBtu * 3,707 mmBtu/hr = 926.8 lbs/hr (7-day avg) = 4,059 tpy

3,707 mmBtu/hr / 9,148 Btu/lb coal * 0.0089 lbs S/lb coal * 2 lbs SO_2/lb S * (1-0.9) = 721.3 lbs/hr (annual avg) SO_2 emissions based on lowest heating value coal and maximum coal S content = 3,159 tpy annual average.

Permit 0063M6R2 Voluntary Limits:

0.15 lbs/MMBtu (Daily Rolling 30 Day Average per Note 5 to Table 2.1 in 0063M6R2)

2435.0 tons per year (Daily rolling 365-day total)

E302: Unit 2 Boiler Unit Specific Limits

20.2.31NMAC limits:

72 % Control (30-day avg)

3,688 mmBtu/hr/ 9,148 Btu/lb coal * 0.0089 lbs S/lb coal * 2 lbs SO_2/lb S * (1-0.72) = 2009.3 lbs/hr (30-day) SO_2 emissions based on lowest heating value coal and maximum coal S content = 8,800.7 tpy annual average. (8,051 tpy based on 9,990 Btu/lb average case coal)

Consent Decree based limits:

0.25 lbs/mmBtu * 3,688 mmBtu/hr = 922 lbs/hr (7-day avg) = 4,038.4 tpy

3,688 mmBtu/hr / 9,148 Btu/lb coal * 0.0089 lbs S/lb coal * 2 lbs SO_2/lb S * (1-0.9) = 717.6 lbs/hr (annual avg) SO_2 emissions based on lowest heating value coal and maximum coal S content = 3,143 tpy annual average.

Permit 0063M6R2 Voluntary Limits:

0.15 lbs/MMBtu (Daily Rolling 30 Day Average per Note 5 to Table 2.1 in 0063M6R2)

2423.0 tons per year (Daily rolling 365-day total)

E 303 : Unit 3 Boiler Unit Specific Limits

NSPS based limits:

1.2 lbs/mmBtu * 5,758 mmBtu/hr = 6,909.6 lbs/hr (3-hr avg) = 30,264 tpy

Consent Decree based limits:

0.25 lbs/mmBtu * 5,758 mmBtu/hr = 1439.5 lbs/hr (7-day avg) = 6,305 tpy

5,758 mmBtu/hr / 9,148 Btu/lb coal * 0.0089 lbs S/lb coal * 2 lbs SO_2/lb S * (1-0.9) = 1120.4 lbs/hr (annual avg) SO_2 emissions based on lowest heating value coal and maximum coal S content = 4,907.2 tpy annual average.

Permit 0063M6R2 Voluntary Limits:

0.15 lbs/MMBtu (Daily Rolling 30 Day Average per Note 5 to Table 2.1 in 0063M6R2)

3783.0 tons per year (Daily rolling 365-day total)

E 304 : Unit 4 Boiler Unit Specific Limits

NSPS based limits:

1.2 lbs/mmBtu * 5,649 mmBtu/hr = 6,778.8 lbs/hr (3-hr avg) = 29,691 tpy

Consent Decree based limits:

0.25 lbs/mmBtu * 5,649 mmBtu/hr = 1,412.3 lbs/hr (7-day avg) = 6,186 tpy

5,649 mmBtu/hr / 9,148 Btu/lb coal * 0.0089 lbs S/lb coal * 2 lbs SO_2/lb S * (1-0.9) = 1.099.2 lbs/hr (annual avg) SO_2 emissions based on lowest heating value coal and maximum coal S content = 4,814 tpy annual average.

Permit 0063M6R2 Voluntary Limits:

0.15 lbs/MMBtu (Daily Rolling 30 Day Average per Note 5 to Table 2.1 in 0063M6R2)

3711.0 tons per year (Daily rolling 365-day total)

Plant-Wide Limits:

Units 1-4 Combined (Note: Although these applicable requirements may be interpreted as applying plant-wide, not just to boiler units, but because boiler units are by far the largest NOx and SO_2 sources, the plant-wide limit calculations given below are applied only to the boiler sources).

0.55 lb/mmBtu plant-wide annual average

Total mmBtu = 18,802 mmBtu/hr

0.55 * 18,802 = 10,341 lbs/hr (avg) = 45,294 tpy

0.46 lbs/mmBtu plant-wide annual average

Total mmBtu = 18,802 mmBtu/hr

0.46 * 18,802 = 8,649 lbs/hr (avg) = 37,882 tpy

13,000 lbs/hr plant-wide limit

13,000 lbs/hr is equivalent to 56,940 tpy

Reconciliation of Limits and Averaging Times for modeling purposes

Short-term (3hr and 24 hr avg) limits

On a unit by unit basis, the shortest term limits are

Unit 1: 4448.4 lbs/hr (3-hr avg)
Unit 2: 4425.6 lbs/hr (3-hr avg) if the 1.2 lbs/mmBtu is applied
Unit 3: 6,909.6 lbs/hr (3-hr avg)
Unit 4: 6,778.8 lbs/hr (3-hr avg)

Total short term is 22,562.4, but this exceeds the 13,000 lbs/hr short-term limit. Therefore for modeling purposes ONLY, not for regulatory limits, emissions have been assigned to the units, following the same procedure used in the Title V Operating Permit Renewal Application and dispersion modeling, as follows:

13,000/22,562.4 * the limit based on 1.2 lbs/mmBtu = a factor of 0.576

Unit 1: 2,562 lbs/hr
Unit 2: 2,549 lbs/hr
Unit 3: 3,980 lbs/hr
Unit 4: 3,905 lbs/hr

Total = 12,996 lbs/hr (which is under the 13,000 lbs/hr limit).

For dispersion modeling purposes, the maximum hourly SO2 emission rates allowed by the applicable regulations as outlined above have been reduced by approximately five (5) percent and rounded to the nearest 100 lbs/hr. With these reductions, the maximum hourly emission rates for the SJGS boiler units are:

Unit 1: 2,400 lbs/hr
Unit 2: 2,400 lbs/hr
Unit 3: 3,800 lbs/hr
Unit 4: 3,700 lbs/hr

These values will be used for the short-term SO_2 dispersion modeling analysis.

NOx:

The following limits apply :

Plant-wide: 9,000 lbs/hr 24-hr. rolling average (NSR/Operating Permit)
Units 1,3,4: 0.7 lbs/mm Btu (3-hr) (NSR/Operating Permit, 40CFR60 Subpart D)
Unit 2: 0.7 lbs/mm Btu (3-hr) (20.2.32 NMAC, NSR/Operating Permit)
Units 1,3,4: 0.45 lbs/mmBtu 3-hr avg (20.2.32 NMAC, NSR/Operating Permit)
Units 1,2,3,4: 0.3 lbs/mmBtu 30-day average (CD 9biii)
Units 1,2,3,4 Operating Permit tpy limits (6892.8, 10,666.6, 10,706.5, 10503.7 tpy respectively)

Applying 0.7 lbs/mmBtu to all Units:

Unit 1: 3,707 mmBtu/hr * 0.7 = 2,595 lbs/hr (3-hr avg)
Unit 2: 3,688 mmBtu/hr * 0.7 = 2,582 lbs/hr (3-hr avg)
Unit 3: 5,758 mmBtu/hr * 0.7 = 4,031 lbs/hr (3-hr avg)
Unit 4: 5,649 mmBtu/hr * 0.7 = 3,954 lbs/hr (3-hr avg)

Total = 13,162 lbs/hr (3 hr avg)

Applying 0.45 lbs/mmBtu to Units 1,3 and 4

Unit 1: 3,707 mmBtu/hr * 0.45 = 1,668 lbs/hr (3-hr avg)
Unit 3: 5,758 mmBtu/hr * 0.45 = 2,591 lbs/hr (3-hr avg)
Unit 4: 5,649 mmBtu/hr * 0.45 = 2,542 lbs/hr (3-hr avg)

Total with 0.7 for Unit 2 and 0.45 for the others is 9,393 lbs/hr. This exceeds the 9,000 lbs/hr limit.

Therefore the lbs/hr NOx for modeling purposes cannot be based exactly on the revised heat input. The values used for dispersion modeling purposes are:

Unit 1: 1573.7 lbs/hr
Unit 2: 2435.3 lbs/hr
Unit 3: 2444.4 lbs/hr
Unit 4: 2398.1 lbs/hr

Applying the 0.3 lbs/mmBtu 30-day average to each unit

Unit 1: 3,707 mmBtu/hr * 0.3 = 1,112 lbs/hr (30-day avg)
Unit 2: 3,688 mmBtu/hr * 0.3 = 1,106 lbs/hr (30-day avg)
Unit 3: 5,758 mmBtu/hr * 0.3 = 1,727 lbs/hr (30-day avg)
Unit 4: 5,649 mmBtu/hr * 0.3 = 1,695 lbs/hr (30-day avg)

Ton per year limits can be obtained from scaling up the lbs/hr 30-day average values as follows:

Unit 1: 1,112 lbs/hr (30-day avg) * 8760/2000 = 4,871 tpy
Unit 2: 1,106 lbs/hr (30-day avg) * 8760/2000 = 4,844 tpy
Unit 3: 1,727 lbs/hr (30-day avg) * 8760/2000 = 7,564 tpy
Unit 4: 1,695 lbs/hr (30-day avg) * 8760/2000 = 7,424 tpy

Total tpy = 24,703 tpy

Scenario A:

The new NOx limit required by federal FIP (40CFR52) is 0.05 lbs/MMBtu for each unit. This requirement becomes effective 5 years after the effective date of the rule. The form has been specified in the FIP and will have a significant impact on the stringency of the limit. The FIP currently requires calculation of a rolling 30-day boiler operating day period (including periods of unit startup, shutdown, and malfunction) to demonstrate compliance. For each unit on each boiler-operating day, the hourly NOx emissions measured in lbs/mmBtu shall be averaged over the hours the unit was in operation to obtain a daily boiler-operating-day average. Each day, the 30day rolling average NOx emission rate for each unit (in lbs/mmBtu) shall be determined by averaging the boiler-operating -day average emission rate from that day with the preceding 29 days. The FIP defines a boiler-operating-day as as any 24-hour period between 12:00 midnight and the following midnight during which fuel is combusted at any time at the steam generating unit. The equivalent potential to emit of NOx can be calculated by assuming full load operation of each unit at the maximum unit heat input as follows:

Unit 1: 3,707 mmBtu/hr * 0.05 lbs/mmBtu * 8760 hrs/yr * 1 ton/2000 lbs = 811.83 tpy
Unit 2: 3,688 mmBtu/hr * 0.05 lbs/mmBtu * 8760 hrs/yr * 1 ton/2000 lbs = 807.67 tpy
Unit 3: 5,758 mmBtu/hr * 0.05 lbs/mmBtu * 8760 hrs/yr * 1 ton/2000 lbs = 1,261.0 tpy
Unit 4: 5,649 mmBtu/hr * 0.05 lbs/mmBtu * 8760 hrs/yr * 1 ton/2000 lbs = 1,237.1 tpy

Scenario B:

The SIP NOx limit is 0.23 lbs/mmBtu. This requirement becomes effective in February 2016. The 0.23 lbs/mmBtu applies to a 30-day rolling average, excluding periods of unit startup, shutdown and malfunction. The equivalent tons per year of NOx can be calculated by assuming full load operation of each unit at the maximum unit heat input as follows:

Unit 1: 3,707 mmBtu/hr * 0.23 lbs/mmBtu * 8760 hrs/yr * 1 ton/2000 lbs = 3,734.4 tpy
Unit 2: 3,688 mmBtu/hr * 0.23 lbs/mmBtu * 8760 hrs/yr * 1 ton/2000 lbs = 3,715.3 tpy
Unit 3: 5,758 mmBtu/hr * 0.23 lbs/mmBtu * 8760 hrs/yr * 1 ton/2000 lbs = 5,800.6 tpy
Unit 4: 5,649 mmBtu/hr * 0.23 lbs/mmBtu * 8760 hrs/yr * 1 ton/2000 lbs = 5,690.8 tpy

PM – Filterable:

For uncontrolled emissions, 80 percent of the ash in the coal is assumed to be emitted as "fly ash" and 20 percent retained as bottom ash. Use current ash content of 22.45% ash.

Short-term (lbs/hr) values based on maximum tph coal rates:

Unit 1 202.6 tph * 0.2245 * 0.80 = 36.39 tph = 72,774 lbs/hr PM
Unit 2 201.6 tph * 0.2245 * 0.80 = 36.21 tph = 72,414 lbs/hr PM
Unit 3 314.7 tph * 0.2245 * 0.80 = 56.52 tph = 113,040 lbs/hr PM
Unit 4 308.7 tph * 0.2245 * 0.80 = 55.45 tph = 110,892 lbs/hr PM

Long-term (TPY) values based on average coal rates:

Unit 1 185.5 tph * 0.2245 * 0.80 = 33.32 tph = 66,632 lbs/hr = 291,846 tpy PM
Unit 2 184.6 tph * 0.2245 * 0.80 = 33.15 tph = 66,308 lbs/hr = 290,430 tpy PM
Unit 3 288.2 tph * 0.2245 * 0.80 = 51.76 tph = 103,521 lbs/hr = 453,424 tpy PM
Unit 4 282.7 tph * 0.2245 * 0.80 = 50.77 tph = 101,546 lbs/hr = 444,771 tpy PM

TOTAL Station PTE = 1,601,586 tpy uncontrolled

For controlled emissions, the following limits apply :

Units 1,2,3,4: 0.05 lbs PM/mm Btu (3-hr) (NSR/Operating Permit,NMAC)
Units 1,3,4: 0.1 lbs PM/mmBtu 3-hr avg (NSR/Operating Permit/NSPS)
Units 1,2,3,4: 0.02 lbs PM2/mmBtu 30-day average (NMAC – note an "OR" applies to this requirement)
Units 1,2,3,4 Operating Permit lb TSP and PM10/hr limits (174.8, 173.9, 271.6, 266.5)
Units 1,2,3,4 Consent Decree 0.015 lbs/mmBtu limit (3 hr avg)

Based on the 0.05 lbs/mmBtu limit:

Unit 1: 3,707 mmBtu/hr * 0.05 = 185.4 lbs/hr (3-hr avg)
Unit 2: 3,688 mmBtu/hr * 0.05 = 184.4 lbs/hr (3-hr avg)
Unit 3: 5,758 mmBtu/hr * 0.05 = 287.9 lbs/hr (3-hr avg)
Unit 4: 5,649 mmBtu/hr * 0.05 = 282.5 lbs/hr (3-hr avg)

Total PTE = 940.2 lbs/hr = 4,118 tpy

Based on Operating Permit Limits

Total PTE = 886.8 lbs/hr = 3,884 tpy

Based on Consent Decree Limits

Unit 1: 3,707 mmBtu/hr * 0.015 = 55.6 lbs/hr (3-hr avg)
Unit 2: 3,688 mmBtu/hr * 0.015 = 55.3 lbs/hr (3-hr avg)
Unit 3: 5,758 mmBtu/hr * 0.015 = 86.4 lbs/hr (3-hr avg)
Unit 4: 5,649 mmBtu/hr * 0.015 = 84.7 lbs/hr (3-hr avg)

Total PTE = 282 lbs/hr = 1,235 tpy.1

Controlled tons per year:

Unit 1: 55.6 lbs/hr = 243.5 tpy
Unit 2: 55.3 lbs/hr = 242.2 tpy
Unit 3: 86.4 lbs/hr = 378.4 tpy
Unit 4: 84.7 lbs/hr = 371.0 tpy

Total PTE = 1,235.1 tpy PM

PM2.5-Total: (condensable plus filterable)

The Total PM 2.5 emissions (condensable plus filterable) is 0.034 lbs/mmBtu based on the permit application submitted to the NMED in September 2011. This limit is based on review of available stack testing results and on the proposed NSPS limit. This limit applies to each individual boiler.

Unit 1: Total PM limit 0.034 lbs/mmBtu
Unit 2: Total PM limit 0.034 lbs/mmBtu
Unit 3: Total PM limit 0.034 lbs/mmBtu
Unit 4: Total PM limit 0.034 lbs/mmBtu

For dispersion modeling purposes, PTE mass emission rates have been calculated based on the maximum hourly heat input rate as follows:

Unit 1: 3,707 mmBtu/hr * 0.034 lbs/mmBtu = 126.0 lbs/hr PM2.5 =552.0 tpy

Unit 2: 3,688 mmBtu/hr * 0.034 lbs/mmBtu = 125.4 lbs/hr PM2.5 = 549.2 tpy

Unit 3: 5,758 mmBtu/hr * 0.034 lbs/mmBtu = 195.8 lbs/hr PM2.5 = 857.5 tpy

Unit 4: 5,649 mmBtu/hr * 0.034 lbs/mmBtu = 192.1 lbs/hr PM2.5 = 841.2 tpy

The ton per year values were calculated assuming 8760 hours per year of operation at full load.

CO:

Based on stack testing results, engineering judgment and input from SJGS, the following limits apply.

Unit 1: 3,000 lbs/hr = 13,140 tpy
Unit 2: 2,000 lbs/hr = 8,760 tpy
Unit 3: 2,000 lbs/hr = 8,760 tpy
Unit 4: 2,000 lbs/hr = 8,760 tpy

VOC:

Based on AP42 emission factor of 0.06 lbs NMVOC/ton of coal (AP42 Section 1.1 Table 1.1-19, pulverized coal, dry bottom, wall fired)

Based on average coal Btu content and revised heat input values

Unit 1: 3,707 mmBtu/hr / 9,990 Btu/lb = 185.5 tons/hr coal
185.5 tons/hr * 0.06 lbs/ton = 11.1 lbs/hr = 48.7 tpy NMVOC

Unit 2: 3,688 mmBtu/hr / 9,990 Btu/lb = 184.6 tons/hr coal
184.6 tons/hr * 0.06 lbs/ton = 11.1 lbs/hr = 48.5 tpy NMVOC

Unit 3: 5,758 mmBtu/hr / 9,990 Btu/lb = 288.2 tons/hr coal
288.2 tons/hr * 0.06 lbs/ton = 17.3 lbs/hr = 75.8 tpy NMVOC

Unit 4: 5,649 mmBtu/hr / 9,990 Btu/lb = 282.7 tons/hr coal
282.7 tons/hr * 0.06 lbs/ton = 17.0 lbs/hr = 74.5 tpy NMVOC

HCl:

Controlled HCl emissions are based on updated EPRI emission factors as used in SJGS's TRI report for the year 2007. The HCl emission factor is 257 lbs HCl/trillion Btu heat input. At maximum heat input and 8,760 hours per year operation, the maximum HCl annual PTE emission rates are:

Unit 1: 3,707 * 10^6 Btu/hr * 8,760 hrs/yr * 257 lbs HCl/10^12 Btu = 8,346 lbs/yr = 4.2 tpy HCl

Unit 2: 3,688 *10^6 Btu/hr * 8,760 hrs/yr * 257 lbs HCl/10^12 Btu = 8,303 lbs/yr = 4.2 tpy HCl

Unit 3: 5,758 *10^6 Btu/hr * 8,760 hrs/yr * 257 lbs HCl/10^12 Btu = 12,963 lbs/yr = 6.5 tpy HCl

Unit 4: 5,649 *10^6 Btu/hr * 8,760 hrs/yr * 257 lbs HCl/10^12 Btu = 12,718 lbs/yr = 6.4 tpy HCl

Station total PTE = 21.3 tpy

Sulfuric Acid:

Scenario A:

The FIP includes a requirement that boiler stack sulfuric acid emissions be limited to no more than 0.00026 lbs/mmBtu. This emission limit is applied to each individual unit. This requirement becomes effective 5 years after the effective date of the rule.

Unit 1: Total Sulfuric Acid limit 0.00026 lbs/mmBtu
Unit 2: Total Sulfuric Acid limit 0.00026 lbs/mmBtu
Unit 3: Total Sulfuric Acid limit 0.00026 lbs/mmBtu
Unit 4: Total Sulfuric Acid limit 0.00026 lbs/mmBtu

These limits are half of the detection limit of the test method required for demonstrating compliance with the FIP. As such, these limits are not achievable, as explained in more detail in Section 20.

Sulfuric Acid is listed as a TAP on 20.2.72.502 Table A. The listed trigger rate is 0.0667 lbs/hr. The SJGS boiler stacks are 400 feet tall (122 meters) and therefore have a multiplier of 533 per 20.2.72.502NMAC Table C giving a trigger rate of 0.0667 * 533 = 35.55 lbs/hr.

For purposes of comparison to the TAP trigger level (not for permit limit purposes) the mass emission rates of sulfuric acid equivalent to 0.00026 lbs/mmBtu have been calculated based on the maximum hourly heat input rate as follows:

Unit 1: 3,707 mmBtu/hr * 0.00026 lbs/mmBtu = 0.96382 lbs/hr

Unit 2: 3,688 mmBtu/hr * 0.00026 lbs/mmBtu = 0.95888 lbs/hr

Unit 3: 5,758 mmBtu/hr * 0.00026 bs/mmBtu = 1.49708 lbs/hr

Unit 4: 5,649 mmBtu/hr * 0.00026 lbs/mmBtu = 1.46874 lbs/hr

Total sulfuric acid = 4.89 lbs/hr = 21.4 tpy.

Ammonia:

Scenario A

Basis 2 ppmv NH_3 in flue gas exhaust, per FIP SCR design requirement.

Exhaust gas rate for Unit's 1/2 (each) 841,388 scfm; Units 3/4 (each) 1,286,109 scfm

Units 1 and 2 (each)

841,388 scfm * 2 scfm NH_3/1,000,000 scfm * 17 lbs/lbmole * 1 lbmole/359 scf = 0.07968 lbs/min = 4.7811 lbs/hr

Units 3 and 4 (each)

1,268,109 scfm * 2 scfm NH_3/1,000,000 scfm * 17 lbs/lbmole * 1 lbmole/359 scf = 0.1280 lbs/min = 7.3083 lbs/hr

Total for facility:

2* 4.7811 + 2 * 7.3083 = 24.1788 lbs/hr NH_3 ammonia slip = 105.9 tpy at 8760 hrs/yr PTE

The NMED TAP (20.2.72.400NMAC) trigger level for ammonia is 1.2 lbs/hr (20.2.72.502 NMAC Table A) but there is a multiplication factor of 533 for stacks between 110 and 120 meters (20.2.72.502 Table C), therefore the adjusted trigger is 639.6 lbs/hr.

Scenario B

Basis 10 ppmv NH_3 in flue gas exhaust, per SNCR design specification.

Exhaust gas rate for Unit's 1/2 (each) 841,388 scfm; Units 3/4 (each) 1,286,109 scfm

Units 1 and 2 (each)

841,388 scfm * 10 scfm NH_3/1,000,000 scfm * 17 lbs/lbmole * 1 lbmole/359 scf = 0.39843 lbs/min = 23.9057 lbs/hr

Units 3 and 4 (each)

1,268,109 scfm * 10 scfm NH_3/1,000,000 scfm * 17 lbs/lbmole * 1 lbmole/359 scf = 0.600497 lbs/min = 36.0298 lbs/hr

Total for facility:

2* 23.9057 + 2 * 36.0298 = 119.87 lbs/hr NH_3 ammonia slip = 525.03 tpy at 8760 hrs/yr

The NMED TAP (20.2.72.400NMAC) trigger level for ammonia is 1.2 lbs/hr (20.2.72.502 NMAC Table A) but there is a multiplication factor of 533 for stacks between 110 and 120 meters (20.2.72.502 Table C), therefore the adjusted trigger is 639.6 lbs/hr.

HF:

Controlled HF emissions are based on updated EPRI emission factors as used in SJGS's TRI report for the year 2007. The HF emission factor is 544 lbs HF/trillion Btu heat input. At maximum heat input and 8,760 hours per year operation, the maximum HF annual emission rates are:

Unit 1: 3,707 * 10^6 Btu/hr * 8,760 hrs/yr * 544 lbs HF/10^12 Btu = 17,665 lbs/yr = 8.8 tpy HF

Unit 2: 3,688 *10^6 Btu/hr * 8,760 hrs/yr * 544 lbs HF/10^12 Btu = 17,575 lbs/yr = 8.8 tpy HF

Unit 3: 5,758 *10^6 Btu/hr * 8,760 hrs/yr * 544 lbs HF/10^12 Btu = 27,439 lbs/yr = 13.7 tpy HF

Unit 4: 5,649 *10^6 Btu/hr * 8,760 hrs/yr * 544 lbs HF/10^12 Btu = 26,920 lbs/yr = 13.4 tpy HF

Station total PTE = 44.7 tpy

Manganese:

Controlled Mn emissions are based on updated EPRI emission factors as used in SJGS's TRI report for the year 2007. The Mn emission factor is 8.5 lbs Mn/trillion Btu heat input. At maximum heat input and 8,760 hours per year operation, the maximum Mn annual emission rates are:

Unit 1: 3,707 * 10^6 Btu/hr * 8,760 hrs/yr * 8.5 lbs Mn/10^12 Btu = 276 lbs/yr =0.14 tpy Mn

Unit 2: 3,688 *10^6 Btu/hr * 8,760 hrs/yr * 8.5 lbs Mn/10^12 Btu = 275 lbs/yr = 0.14 tpy Mn

Unit 3: 5,758 *10^6 Btu/hr * 8,760 hrs/yr * 8.5 lbs Mn/10^12 Btu = 429 lbs/yr = 0.21 tpy Mn

Unit 4: 5,649 *10^6 Btu/hr * 8,760 hrs/yr * 8.5 lbs Mn/10^12 Btu = 421 lbs/yr = 0.21 tpy Mn

Station total PTE = 0.7 tpy

Benzene:

Controlled benzene emissions are based on updated EPRI emission factors as used in SJGS's TRI report for the year 2007. The benzene emission factor is 3.9 lbs benzene/trillion Btu heat input. At maximum heat input and 8,760 hours per year operation, the maximum benzene annual emission rates are:

Unit 1: 3,707 * 10^6 Btu/hr * 8,760 hrs/yr * 3.9 lbs benzene /10^12 Btu = 127 lbs/yr =0.063 tpy benzene

Unit 2: 3,688 *10^6 Btu/hr * 8,760 hrs/yr * 3.9 lbs benzene /10^12 Btu = 126 lbs/yr = 0.063 tpy benzene

Unit 3: 5,758 *10^6 Btu/hr * 8,760 hrs/yr * 3.9 lbs benzene /10^12 Btu = 197 lbs/yr = 0.098 tpy benzene

Unit 4: 5,649 *10^6 Btu/hr * 8,760 hrs/yr * 3.9 lbs benzene /10^12 Btu = 193 lbs/yr = 0.096 tpy benzene

Station total PTE = 0.3 tpy

COOLING TOWERS

Emission Points E406 – E 411 Cooling Tower Particulate Matter Drift Loss

The TDS for Units E406, E407 and E409 have been changed from 5,500 mg/l TDS to 6,000 mg/l TDS and Units E408 and E410 have been changed from 4,500 mb/l to 3,900 mg/l. Overall PM emissions in the cooling tower drift remain essentially unchanged.

TSP:

The potential TSP particulate matter contained in cooling tower drift loss has been calculated as follows:

E_{TSP} = % drift * circulating water rate * TDS

The percent drift is based on cooling tower manufacturer specifications and the circulating water rate is the maximum capacity of the circulating water pumps for each unit.

An example calculation is given below. The calculation parameters and results are summarized in the following table.

For the Unit 1 cooling tower (E406) the drift rate is 0.002 percent (0.00002), the maximum circulation rate is 170,000 gpm and the maximum TDS is 6,000 mg/l.

E_{TSP} = 0.00002 * 170,000 gal/min * 6,000 mg/l * 3.785 l/gal * 1 g/1,000 mg * 1 lb/453.6 g * 60 min/hr = 10.2 lbs/hr TSP

This is a conservative calculation as larger drift droplets settle to the ground close to the cooling tower before they can evaporate and therefore do not contribute to airborne PM emissions. No credit has been taken for this wet deposition of cooling tower drift.

PM10:

Instead of assuming that PM10 equals TSP, a more realistic calculation can be performed using the method given in "Calculating Realistic PM10 Emissions from Cooling Towers", Abstract No. 216, Session AM-1b, Reisman, Joel and Frisbie, Gordon, 2001 National Air and Waste Management Association Meeting (Attachment A-0063-7-CT_PM_Reisman).

Using this method approximately 23.5 percent of the total PM is PM10 for Units E406, E407 and E409. For E408 and E410 approximately 38.7 percent of the total PM is PM10.

The complete calculations are given in the spreadsheets in Section 7.

PM2.5:

Using the same methodology as used for PM10 approximately, 0.196 percent of the total PM is PM2.5 for all of the cooling tower units.

The complete calculations are given in the spreadsheets in Section 7.

Summary of Cooling Tower PM in Drift

Emission Unit	Cooling Tower	% Drift	Circulation Rate gpm	TDS (mg/l)	TSP lbs/hr	TSP tpy	PM10 lbs/hr	PM10 tpy	PM2.5 lbs/hr	PM2.5 tpy
E406	Unit 1 CT	0.002	170,000	6,000	10.20	44.7	2.40	10.5	0.020	0.0875
E407	Unit 2 CT	0.002	165,000	6,000	9.90	43.4	2.33	10.2	0.019	0.085
E408	Unit 3 CT	0.0015	220,000	3,900	6.43	28.2	2.49	10.9	0.013	0.055
E409	Unit 4 CT	0.002	227,500	6,000	13.65	59.8	3.21	14.1	0.027	0.12
E410	Aux 1/Aux 2 CT	0.002	35,000	3,900	1.36	5.98	0.53	2.31	0.0027	0.012

Note that the Aux 1 and Aux 2 cooling towers were previously identified as separate emissions units. However, these cooling towers share the same cooling water basin and have identical exhaust parameters. Therefore to simplify the permit these two cooling towers have been combined as emissions Unit 410 and E411 has been deleted. Previously the circulating cooling water rate associated with E410 was 5,000 gpm and E411 was 30,000 gpm. The circulating water rate for the combined E410 is the sum of these two, 35,000 gpm.

ASH HANDLING SYSTEMS

E505 (S512, SU212) Unit 3 Fly Ash Silo

Previous uncontrolled emission calculations for transfer of ash into the silo were based on the AP42 13.2.4.3"drop equation". More recent practice has been to use AP42 11.12 for "uncontrolled" silo loading for fly ash. Because the silo loading system is a closed system and the only outlet is through the silo bin vent, an uncontrolled emission rate is not particularly meaningful calculation but is provided because the application forms request this information.

Uncontrolled emissions:

Estimation Method: AP42 11.12 (Table 11.12-2)

E (PM) = 3.14 lbs/ton

E(PM10) = 1.1 lbs/ton

E(PM2.5) = 0.1578 lbs/ton

Fly Ash Throughput = 453,046 tpy (calculated from annual coal use with average coal, 0.2245 ash fraction and 80% fly ash minus what leaves the stack)

E(PM) = 3.14 lbs/ton * 453,046 tpy = 1,422,564 lbs/yr = 162.39 lbs/hr =711 tpy PM (TSP)

E(PM10) = 1.1 lbs/ton * 453,046 tpy = 489351 lbs/yr = 56.889 lbs/hr = 249 tpy PM (TSP)

E(PM2.5) = 0.1578 lbs/ton * 453,046 tpy =71,491lbs/yr = 8.1610 lbs/hr = 35.7 tpy PM (TSP)

Controlled emissions are calculated by using an outlet "grain loading" concentration. The baghouse outlet concentration will not exceed 0.01 grains/scf as a conservative value. Actual specification is 0.005 gr/scf. The air flow through the silo bin vent filter will not exceed 25,400 cfm and is limited by the capacity of the air blowers.

Controlled TSP/PM10 = 0.01 grains/ft3 * 1 lb/7,000 grains * 25,400 ft3/min * 60 min/hr = 2.1771 lbs/hr

2.1771 lbs/hr * 8,760 hrs/yr * 2000 lbs/ton = 9.54 tpy

It would be overly conservative to assume that PM2.5 emissions are equal to the TSP and PM10 emissions because only a small fraction of the fly ash is PM2.5. Therefore PM2.5 emissions have been estimated by applying the ratio of controlled PM2.5 to controlled PM/PM10 from AP42 11.12 (i.e. PM2.5 equals 0.06*PM). Therefore PM2.5 controlled emissions are:

PM2.5 = 0.06* 2.1771 lbs/hr = 0.130626 lbs/hr = 0.57214 tpy

Note that the tpy calculation assumes that the blowers from the fabric filter operates at full flow continuously. In actual operation, the blower from the fabric filter will not operate continuously. Therefore, this calculation is conservative and overestimates controlled emissions.

E506 (S513, SU213) Unit 4 Fly Ash Silo

Previous uncontrolled emission calculations for transfer of ash into the silo were based on the AP42 13.2.4.3"drop equation". More recent practice has been to use AP42 11.12 for "uncontrolled" silo loading for fly ash. Because the silo loading system is a closed system and the only outlet is through the silo bin vent, an uncontrolled emission rate is not particularly meaningful calculation but is provided because the application forms request this information.

Uncontrolled emissions:

Estimation Method: AP42 11.12 (Table 11.12-2)

E (PM) = 3.14 lbs/ton

E(PM10) = 1.1 lbs/ton

E(PM2.5) = 0.1578 lbs/ton

Fly Ash Throughput = 444,771 tpy (calculated from annual coal use with average coal, 0.2245 ash fraction and 80% fly ash minus what leaves the stack)

E(PM) = 3.14 lbs/ton * 444,771 tpy = 1,396,581 lbs/yr = 159.4 lbs/hr =698 tpy PM (TSP)

E(PM10) = 1.1 lbs/ton * 444,771 tpy = 489248 lbs/yr = 55.8502 lbs/hr = 244 tpy PM (TSP)

E(PM2.5) = 0.1578 lbs/ton * 444,771 tpy =70,185lbs/yr = 8.0120 lbs/hr = 35.1 tpy PM (TSP)

Controlled emissions are calculated by using an outlet "grain loading" concentration. The baghouse outlet concentration will not exceed 0.01 grains/scf as a conservative value. Actual specification is 0.005 gr/scf. The air flow through the silo bin vent filter will not exceed 25,400 cfm and is limited by the capacity of the air blowers.

Controlled TSP/PM10/PM2.5 = 0.01 grains/ft3 * 1 lb/7,000 grains * 25,400 ft3/min * 60 min/hr = 2.1771 lbs/hr

2.1771 lbs/hr * 8,760 hrs/yr * 2000 lbs/ton = 9.54 tpy

It would be overly conservative to assume that PM2.5 emissions are equal to the TSP and PM10 emissions because only a small fraction of the fly ash is PM2.5. Therefore PM2.5 emissions have been estimated by applying the ratio of controlled PM2.5 to controlled PM/PM10 from AP42 11.12 (i.e. PM2.5 equals 0.06*PM). Therefore PM2.5 controlled emissions are:

PM2.5 = 0.06* 2.1771 lbs/hr = 0.130626 lbs/hr = 0.57214 tpy

Note that the tpy calculation assumes that the blowers from the fabric filter operates at full flow continuously. In actual operation, the blower from the fabric filter will not operate continuously. Therefore, this calculation is conservative and overestimates controlled emissions.

E507 (S514, SU210) Unit 1 Fly Ash Silo Unloading

Estimation Method: AP42 13.2.4.3

Uncontrolled emission equation:

$E = k(0.0032)[U/5)^{1.3}/(M/2)^{1.4}]$ lbs/ton

k= 0.74 (TSP constant)

k= 0.35 (PM10 constant)

k = 0.053 (PM2.5 constant)

U= 10.55 mph (average wind speed)

M = 1.0 % (water added to fly ash)

Fly Ash Throughput = 291,846 tpy (calculated from annual coal use with average coal, 0.2245 ash fraction and 80% fly ash minus what leaves the stack)

$E\ (TSP) = 0.74*0.0032*[(10.55/5)^{1.3}/(1.0/2)^{1.4}] = 0.0165$ lbs/ton

0.0165 lbs TSP/ton * 291,846 tpy = 4,815 lbs/yr TSP = 0.55 lbs/hr TSP

$E\ (PM10) = 0.35*0.0032*[(10.55/5)^{1.3}/(1.0/2)^{1.4}] = 0.0078$ lbs/ton

0.0078 lbs PM10/ton * 291,846 tpy = 2,276 lbs/yr PM10 = 0.26 lbs/hr PM10

$E(PM2.5) = 0.053 * 0.0032*[(10.55/5)^{1.3}/(1.0/2)^{1.4}] = 0.0011815$ lbs/ton PM2.5

0.0011815 lbs/ton PM2.5 * 291,846 tpy = 344.81 lbs/yr = 0.039362 lbs/hr = 0.1724 tpy PM2.5

Control Factor for Silo Unloading = 0.0%

Controlled TSP = 2.4 tpy = 0.55 lbs/hr

Controlled PM10 = 1.1 tpy = 0.26 lbs/hr

Controlled PM2.5 = 0.17 tpy = 0.039 lbs/hr

E508 (S515, SU211) Unit 2 Fly Ash Silo Unloading

Estimation Method: AP42 13.2.4.3

Uncontrolled emission equation:

$E = k(0.0032)[U/5)^{1.3}/(M/2)^{1.4}]$ lbs/ton

k= 0.74 (TSP constant)

k= 0.35 (PM10 constant)

k = 0.053 (PM2.5 constant)

U= 10.55 mph (average wind speed)

M = 1.0 % (water added to fly ash)

Fly Ash Throughput = 290,430 tpy (calculated from annual coal use with average coal, 0.2245 ash fraction and 80% fly ash minus what leaves the stack)

E (TSP) = $0.74*0.0032*[(10.55/5)^{1.3}/(1.0/2)^{1.4}]$ = 0.0165 lbs/ton

0.0165 lbs TSP/ton * 290,430 tpy = 4,792 lbs/yr TSP = 0.55 lbs/hr TSP

E (PM10) = $0.35*0.0032*[(10.55/5)^{1.3}/(1.0/2)^{1.4}]$ = 0.0078 lbs/ton

0.0078 lbs PM10/ton * 290,430 tpy = 2,265 lbs/yr PM10 = 0.26 lbs/hr PM10

E(PM2.5) = $0.053 * 0.0032*[(10.55/5)^{1.3}/(1.0/2)^{1.4}]$ = 0.0011815 lbs/ton PM2.5

0.0011815 lbs/ton PM2.5 * 290,430 tpy = 343.14 lbs/yr = 0.039172 lbs/hr = 0.17157 tpy PM2.5

Control Factor for Silo Unloading = 0.0%

Controlled TSP = 2.4 tpy = 0.55 lbs/hr

Controlled PM10 = 1.1 tpy = 0.26 lbs/hr

Controlled PM2.5 = 0.17 tpy = 0.39 lbs/hr

E509 (S516, SU212) Unit 3 Fly Ash Silo Unloading

Estimation Method: AP42 13.2.4.3

Uncontrolled emission equation:

E = $k(0.0032)[U/5)^{1.3}/(M/2)^{1.4}]$ lbs/ton

k= 0.74 (TSP constant)

k= 0.35 (PM10 constant)

k = 0.053 (PM2.5 constant)

U= 10.55 mph (average wind speed)

M = 1.0 % (water added to fly ash)

Fly Ash Throughput = 453,424 tpy (calculated from annual coal use with average coal, 0.2245 ash fraction and 80% fly ash minus what leaves the stack)

E (TSP) = $0.74*0.0032*[(10.55/5)^{1.3}/(1.0/2)^{1.4}]$ = 0.0165 lbs/ton

0.0165 lbs TSP/ton * 453,424 tpy = 7,481 lbs/yr TSP = 0.85 lbs/hr TSP

E (PM10) = $0.35*0.0032*[(10.55/5)^{1.3}/(1.0/2)^{1.4}]$ = 0.0078 lbs/ton

0.0078 lbs PM10/ton * 453,424 tpy = 3,538 lbs/yr PM10 = 0.40 lbs/hr PM10

E(PM2.5) = $0.053 * 0.0032*[(10.55/5)^{1.3}/(1.0/2)^{1.4}]$ = 0.0011815 lbs/ton PM2.5

0.0011815 lbs/ton PM2.5 * 453,424 tpy = 535.72 lbs/yr = 0.061155 lbs/hr = 0.26786 tpy PM2.5

Control Factor for Silo Unloading = 0.0%

Controlled TSP = 3.7 tpy = 0.85 lbs/hr

Controlled PM10 = 1.8 tpy = 0.40 lbs/hr

Controlled PM2.5 =0.27 tpy = 0.061 lbs/hr

E510 (S517, SU213) Unit 4 Fly Ash Silo Unloading

Estimation Method: AP42 13.2.4.3

Uncontrolled emission equation:

E = $k(0.0032)[U/5)^{1.3}/(M/2)^{1.4}]$ lbs/ton

k= 0.74 (TSP constant)

k= 0.35 (PM10 constant)

k = 0.053 (PM2.5 constant)

U= 10.55 mph (average wind speed)

M = 1.0 % (water added to fly ash)

Fly Ash Throughput = 444,471 tpy (calculated from annual coal use with average coal, 0.2245 ash fraction and 80% fly ash minus what leaves the stack)

E (TSP) = $0.74*0.0032*[(10.55/5)^{1.3}/(1.0/2)^{1.4}]$ = 0.0165 lbs/ton

0.0165 lbs TSP/ton * 444,771 tpy = 7,334 lbs/yr TSP = 0.84 lbs/hr TSP

E (PM10) = $0.35*0.0032*[(10.55/5)^{1.3}/(1.0/2)^{1.4}]$ = 0.0078 lbs/ton

0.0078 lbs PM10/ton * 444,471 tpy = 3,467 lbs/yr PM10 = 0.40 lbs/hr PM10

E(PM2.5) = 0.053 * 0.0032*[$(10.55/5)^{1.3}/(1.0/2)^{1.4}$] = 0.0011815 lbs/ton PM2.5

0.0011815 lbs/ton PM2.5 * 444,471 tpy = 525.14 lbs/yr = 0.059948 lbs/hr = 0.26257 tpy PM2.5

Control Factor for Silo Unloading = 0.0%

Controlled TSP = 3.7 tpy = 0.84 lbs/hr

Controlled PM10 = 1.7 tpy = 0.40 lbs/hr

Controlled PM10 = 0.26 tpy = 0.060 lbs/hr

Unit 1 Ash Silo Bin Vent (Baghouse)

This source and emissions unit is S518/E518.

Previous uncontrolled emission calculations for transfer of ash into the silo were based on the AP42 13.2.4.3"drop equation". More recent practice has been to use AP42 11.12 for "uncontrolled" silo loading for fly ash. Because the silo loading system is a closed system and the only outlet is through the silo bin vent, an uncontrolled emission rate is not particularly meaningful calculation but is provided because the application forms request this information. Previous controlled emission calculations were based on a percent removal basis. These calculations are being updated to use the grain loading methodology to be consistent with the current calculation procedures as used in more recent permitting actions (such as for emission units 505 and 506 above). In addition, the current bin vent filter is being supplemented with an addition bin vent to supply more filter area (i.e. reduce the air/cloth ratio) which will relieve stress and maintenance issues with the current bin vent. This addition will not increase the overall air flow rate through the ash silos (and therefore through the bin vents). The air flow derives from the ash blowers, which transport the ash into the silos. The ash blowers are not being modified. The maximum capacity of the ash blowers will remain at 18,645 acfm. The outlet of the new section of the bin vent filter will be ducted to the existing bin vent outlet so there will no new emission point and the stack parameters (exhaust flow rate, exit diameter, velocity temperature etc) will not change. Both the existing section and new section of the bin vents have a specification not to exceed 0.01 gr/cf.

Uncontrolled Silo Emissions

Estimation Method: AP42 11.12 (Table 11.12-2)

E (PM) = 3.14 lbs/ton

E(PM10) = 1.1 lbs/ton

E(PM2.5) = 0.1578 lbs/ton

Unit 1 fly ash throughput is 291,846 tpy (based on 0.2245 coal ash fraction and 20% of ash dropping out as boiler bottom ash).

E(PM) = 3.14 lbs/ton * 291,846 tpy = 916,396 lbs/yr = 104.61 lbs/hr = 458.2 tpy PM (TSP)

E(PM10) = 1.1 lbs/ton * 291,846 tpy = 321,031 lbs/yr = 36.647 lbs/hr = 160.5 tpy PM (TSP)

E(PM2.5) = 0.1578 lbs/ton * 291,846 tpy =46,053 lbs/yr = 5.257 lbs/hr = 23.03 tpy PM (TSP)

Controlled Silo Emissions

For PM and TSP the grain loading rate of 0.01 gr/cf gives:

Controlled TSP/PM10 = 0.01 grains/ft3 * 1 lb/7,000 grains * 18,645 ft3/min * 60 min/hr = 1.5981 lbs/hr

1.5981 lbs/hr * 8,760 hrs/yr * 2000 lbs/ton = 6.9998 tpy TSP/PM10

It would be overly conservative to assume that PM2.5 emissions are equal to the TSP and PM10 emissions because only a small fraction of the fly ash is PM2.5. Therefore PM2.5 emissions have been estimated by applying the ratio of controlled PM2.5 to controlled PM/PM10 from AP42 11.12 (i.e. PM2.5 equals 0.06*PM). Therefore PM2.5 controlled emissions are:

PM2.5 = 0.06* 1.5981 lbs/hr = 0.095886 lbs/hr = 0.41998 tpy

Unit 2 Ash Silo Bin Vent (Baghouse)

This source and emissions unit is number S519/E519.

Previous uncontrolled emission calculations for transfer of ash into the silo were based on the AP42 13.2.4.3"drop equation". More recent practice has been to use AP42 11.12 for "uncontrolled" silo loading for fly ash. Because the silo loading system is a closed system and the only outlet is through the silo bin vent, an uncontrolled emission rate is not particularly meaningful calculation but is provided because the application forms request this information. Previous controlled emission calculations were based on a percent removal basis. These calculations are being updated to use the grain loading methodology to be consistent with the current calculation procedures as used in more recent permitting actions (such as for emission units 505 and 506 above). In addition, the current bin vent filter is being supplemented with an addition bin vent to supply more filter area (i.e. reduce the air/cloth ratio) which will relieve stress and maintenance issues with the current bin vent. This addition will not increase the overall air flow rate through the ash silos (and therefore through the bin vents). The air flow derives from the ash blowers, which transport the ash into the silos. The ash blowers are not being modified. The maximum capacity of the ash blowers will remain at 18,645 acfm. The outlet of the new section of the bin vent filter will be ducted to the existing bin vent outlet so there will no new emission point and the stack parameters (exhaust flow rate, exit diameter, velocity temperature etc) will not change. Both the existing section and new section of the bin vents have a specification not to exceed 0.01 gr/acfm.

Uncontrolled Silo Emissions:

Estimation Method: AP42 11.12 (Table 11.12-2)

E (PM) = 3.14 lbs/ton

E(PM10) = 1.1 lbs/ton

E(PM2.5) = 0.1578 lbs/ton

Unit 2 fly ash throughput is 290,430 tpy (based on 0.2245 coal ash fraction and 20% of ash dropping out as boiler bottom ash).

E(PM) = 3.14 lbs/ton * 290,430 tpy = 911,950 lbs/yr = 104.10 lbs/hr = 456.00 tpy PM (TSP)

E(PM10) = 1.1 lbs/ton * 290,430 tpy = 319,473 lbs/yr = 36.470 lbs/hr = 159.7 tpy PM (TSP)

E(PM2.5) = 0.1578 lbs/ton * 290,430 tpy =45,830 lbs/yr = 5.232 lbs/hr = 22.915 tpy PM (TSP)

Controlled Silo Emissions

For PM and TSP the grain loading rate of 0.01 gr/cf gives:

Controlled TSP/PM10 = 0.01 grains/ft3 * 1 lb/7,000 grains * 18,645 ft3/min * 60 min/hr = 1.5981 lbs/hr

1.5981 lbs/hr * 8,760 hrs/yr * 2000 lbs/ton = 6.9998 tpy TSP/PM10

It would be overly conservative to assume that PM2.5 emissions are equal to the TSP and PM10 emissions because only a small fraction of the fly ash is PM2.5. Therefore PM2.5 emissions have been estimated by applying the ratio of controlled PM2.5 to controlled PM/PM10 from AP42 11.12 (i.e. PM2.5 equals 0.06*PM). Therefore PM2.5 controlled emissions are:

PM2.5 = 0.06* 1.5981 lbs/hr = 0.095886 lbs/hr = 0.41998 tpy

EMERGENCY GENERATORS

Emergency Generators (E602, E603, E604, E605, E606)

The emergency generators are exempt equipment.

VEHICLE TRAFFIC ROAD DUST

Paved Roads

The current (12/03) AP42 methodology indicates that different classes of vehicles using the same roads should be aggregated into an average weight for the vehicles. Therefore, vehicle emission calculations for SJGS paved roads have been calculated as a group using this methodology. The current vehicle fleet, vehicle travel routes and vehicle miles traveled (VMT) was reviewed and updated as needed.

Scenario A:

Scenario A includes the addition of truck traffic to deliver anhydrous ammonia for the SCR NOx control system and truck delivery of the sorbent material for use in the sorbent injection system for control of H_2SO4 emissions.

The paved road emissions for Scenario A are summarized below.

	PM		PM10		PM2.5	
	Lbs/hr	tpy	Lbs/hr	tpy	Lbs/hr	tpy
Uncontrolled	26.51	110.95	5.30	22.19	1.30	5.45
Controlled	16.44	68.79	3.29	13.76	0.81	3.38

The detailed calculations are summarized in the spreadsheets attached in Section 7.

Scenario B:

Scenario B includes the addition of truck traffic to deliver urea for the SNCR NOx control system.

The paved road emissions for Scenario B are summarized below.

	PM		PM10		PM2.5	
	Lbs/hr	tpy	Lbs/hr	tpy	Lbs/hr	tpy
Uncontrolled	26.49	110.86	5.30	22.17	1.30	5.44
Controlled	16.42	68.73	3.28	13.75	0.81	3.37

The detailed calculations are summarized in the spreadsheets attached in Section 7. Note that there is no significant change in emission rates between Scenario A and B.

Unpaved Roads

The current (12/03) AP42 methodology indicates that different classes of vehicles using the same roads should be aggregated into an average weight for the vehicles. Therefore, vehicle emission calculations for SJGS paved roads have been calculated as a group using this methodology. The current vehicle fleet, vehicle travel routes and vehicle miles traveled (VMT) was reviewed and updated as needed. The results are summarized below. Road dust control efficiency, based on road watering, has not been changed.

	PM		PM10		PM2.5	
	Lbs/hr	tpy	Lbs/hr	tpy	Lbs/hr	tpy
Uncontrolled	47.3	170.2	14.2	50.9	1.42	5.08
Controlled	21.65	77.9	6.60	23.8	0.66	2.38

The detailed calculations are summarized in the spreadsheets attached in Section 7.

Limestone Handling and Processing

The total annual limestone consumption is estimated at 227,000 tpy. Potential particulate emissions from limestone handling and processing are from truck delivery to the limestone pile (truck travel and truck unloading), limestone pile maintenance, loading limestone to the limestone silo, and limestone processing.

E801 (S801) Limestone Delivery Truck Unloading

Estimation Method: AP42 13.2.4.3

Uncontrolled emission equation:

$E = k(0.0032)[U/5)^{1.3}/(M/2)^{1.4}]$ lbs/ton

k= 0.74 (TSP constant)

k= 0.35 (PM10 constant)

k = 0.053(PM2.5 constant)

U= 10.55 mph (average wind speed)

M = 0.70 % (moisture content of crushed limestone per AP42, Section 13.2.2, Table 13.2.4-1)

Material used = 227,000 tpy

$E\ (TSP) = 0.74*0.0032*[(10.55/5)^{1.3}/(0.7/2)^{1.4}] = 0.0272$ lbs/ton

0.0272 lbs TSP/ton * 227,000 tpy = 6,174 lbs/yr TSP = 3.1 tpy = 0.70 lbs/hr TSP

$E\ (PM10) = 0.35*0.0032*[(10.55/5)^{1.3}/(0.7/2)^{1.4}] = 0.0129$ lbs/ton

0.0129 lbs PM10/ton * 227,000 tpy = 2,928 lbs/yr PM10 = 1.46 tpy = 0.33 lbs/hr PM10

$E(PM2.5) = 0.053 * 0.0032*[(10.55/5)^{1.3}/(0.7/2)^{1.4}] = 0.0019467$ lbs/ton

0.0019476 lbs/ton * 227,000 tpy = 441.90 lbs/yr = 0.05045 lbs/hr = 0.22 tpy

Control Factor for Limestone Unloading = 0.0%

Controlled TSP = 3.1 tpy = 0.70 lbs/hr

Controlled PM10 = 1.5 tpy = 0.33 lbs/hr

Controlled PM2.5 = 0.22 tpy = 0.050 lbs/hr

E802 (S804) Limestone Pile Maintenance

Estimation Method: AP42 11.9.2

Uncontrolled emission equation:

E (TSP) = (5.7)*$s^{1.2}/M^{1.3}$ * hours operation/yr
E(PM10) = 0.75*$s^{1.5}/M^{1.4}$ * hours operation/yr
E(PM2.5) = 0.022 * TSP

where

s = 1.6 (percent silt content of crushed limestone)
M = 0.7 (percent moisture content of crushed limestone)
Hours/year = 1,300 (dozer operation hours)

E(TSP) = (5.7)*$1.6^{1.2}/0.7^{1.3}$ * 1,300 = 20,708 lbs/yr = 10.4 tpy TSP

E(PM10) = 0.75*$1.6^{1.5}/0.7^{1.4}$ * 1,300 = 3,251 lbs/yr = 1.6 tpy PM10

E(PM2.5) = 0.022 * 20,708 lbs/yr = 455.58 lbs/yr = 0.052006 lbs/hr = 0.227788 tpy

Control Factor = 0.0%

Controlled TSP = 10.4 tpy = 2.36 lbs/hr
Controlled PM10 = 1.6 tpy = 0.37 lbs/hr
Controlled PM2.5 = 0.23 tpy = 0.052 lbs/hr

E803 Limestone Silo Loading

Estimation Method AP42 11.19.2-4

The emission factors for loading crushed stone material into storage bins controlled with fabric filers are:

E (PM) = 0.0099 lbs/ton
E(PM10) = 0.0016 lbs.ton
E(PM2.5) = 0.0006 lbs/ton

This emission factors give the following for controlled PM emissions

PM = 0.0099 lbs/ton * 227,000 tpy = 2,247.3 lbs/yr = 0.25654 lbs/hr = 1.12365 tpy

PM10 = 0.0016 lbs/ton * 227,000 tpy = 363.2 lbs/yr = 0.04146 lbs/hr = 0.1816 tpy

PM2.5 = 0.0006 lbs/ton * 227,000 tpy = 136.2 lbs/yr = 0.015548 lbs/hr = 0.0681 tpy

Uncontrolled emissions for this source are estimated by assuming a fabric control efficiency of 99.5 %. Therefore uncontrolled emissions are:/
PM (uncontrolled) = 2,247.2 lbs/yr / (1-0.995) = 449,460 lbs/yr = 51.3 lbs/hr = 222.5 tpy

PM10 (uncontrolled) = 363.2 lbs/yr / (1-0.995) = 72,640 lbs/yr = 36.3 lbs/hr = 8.3 tpy

PM2.5 (uncontrolled) = 136.2 lbs/yr / (1-0.995) = 27,240 lbs/yr = 13.6 lbs/hr = 3.1 tpy

E804 Limestone Hopper Transfer Point

Note: This source is insignificant/exempt based on emissions but has an applicable NSPS (Subpart OOO)

Estimation Method AP42 11.19.2

The emission factors for uncontrolled crushed stone material for transfer points are:

E (PM) = 0.003 lbs/ton
E(PM10) = 0.00110 lbs.ton
E(PM2.5) = 0.00031087 lbs/ton (based on ratio of controlled PM10/PM2.5 because there is no PM2.5 factor listed for uncontrolled PM2.5)

This emission factors give the following for uncontrolled PM emissions

PM = 0.003 lbs/ton * 227,000 tpy = 681 lbs/yr = 0.077740 lbs/hr = 0.3405 tpy

PM10 = 0.00110 lbs/ton * 227,000 tpy = 249.7 lbs/yr = 0.02850 lbs/hr = 0.12485 tpy

PM2.5 = 0.00031087 lbs/ton * 227,000 tpy = 70.5675 lbs/yr = 0.0080557 lbs/hr = 0.035284 tpy

This transfer point is enclosed. Controlled emissions for this source is estimated by using a 80 percent control efficiency for the enclosure.

PM (controlled) = 681 lbs/yr * (1-0.8) = 136.2 lbs/yr = 0.015548 lbs/hr = 0.0681 tpy

PM10 (controlled) = 249.7 lbs/yr * (1-0.8) = 49.94 lbs/yr = 0.005701 lbs/hr = 0.02497 tpy

PM2.5 (controlled) = 70.5675 lbs/yr * (1-0.8) = 14.1135lbs/yr = 0.0016111 lbs/hr = 0.007057 tpy

E805 Limestone Processing

This emission point consists of two sources S807 and S808. S807 is a transfer point from the limestone hopper to a weigh belt and S808 is the transfer point from the weigh belt to a ball mill. The ball mill itself is not an emission source as the milling is a wet process that does not produce emissions. Sources S807 and S808 are combined into a single emission point, E805, because they are both located inside the same building. The building serves as a control for these sources with an estimated control efficiency of 80 percent.

Note: This source is insignificant/exempt based on emissions but has an applicable NSPS (Subpart OOO)

Estimation Method AP42 11.19.2

The emission factors for uncontrolled crushed stone material for transfer points are:

E (PM) = 0.003 lbs/ton
E(PM10) = 0.00110 lbs.ton
E(PM2.5) = 0.00031087 lbs/ton (based on ratio of controlled PM10/PM2.5 because there is no PM2.5 factor listed for uncontrolled PM2.5)

This emission factors give the following for uncontrolled PM emissions

PM (uncontrolled) = 0.003 lbs/ton * 227,000 tpy = 681 lbs/yr = 0.077740 lbs/hr = 0.03405 tpy

PM10 (uncontrolled) = 0.00110 lbs/ton * 227,000 tpy = 249.7 lbs/yr = 0.02850 lbs/hr = 0.12485 tpy

PM2.5 (uncontrolled) = 0.00031087 lbs/ton * 227,000 tpy = 70.5675 lbs/yr = 0.0080557 lbs/hr = 0.035284 tpy

This transfer point is enclosed. Controlled emissions for this source is estimated by using a 80 percent control efficiency for the enclosure.

PM (controlled) = 681 lbs/yr * (1-0.8) = 136.2 lbs/yr = 0.015548 lbs/hr = 0.0681 tpy

PM10 (controlled) = 249.7 lbs/yr * (1-0.8) = 49.94 lbs/yr = 0.005701 lbs/hr = 0.02497 tpy

PM2.5 (controlled) = 70.5675 lbs/yr * (1-0.8) = 14.1135lbs/yr = 0.0016111 lbs/hr = 0.007057 tpy

These emissions are for each of the two transfer points. Therefore total E805 emissions are:

PM (uncontrolled) = 2* 0.077740 lbs/hr = 0.15548 lbs/hr = 0.68100 tpy
PM10 (uncontrolled) = 2 * 0.02850 lbs/hr = 0.057000 lbs/hr = 0.24966 tpy
PM2.5 (uncontrolled) = 2 * 0.0080557 lbs/hr = 0.016111 lbs/hr = 0.070568 tpy

PM (controlled) = 2 * 0.015548 lbs/hr = 0.031096 lbs/hr = 0.13620 tpy
PM10 (controlled) = 2 * 0.005701 lbs/hr = 0.011402 lbs/hr = 0.04994 tpy
PM2.5 (controlled) = 2 * 0.0016111 lbs/hr = 0.003222 lbs/hr = 0.01411 tpy

Activated Carbon Storage Silo Bin Vents (Baghouses):

The activated carbon will be stored in silos. There will be one silo for each boiler unit. Each silo will have a passive (i.e. no fan) fabric filter to control PM emissions from any air vented from the silos. These silos have been given source, emission and control unit numbers as follows:

S901/E901 – Unit 1 boiler AC silo
S902/E902 – Unit 2 boiler AC silo
S903/E903 – Unit 3 boiler AC silo
S904/E904 – Unit 4 boiler AC silo

The emission source (S number) is each silo. The emissions unit (point where emissions exit to the atmosphere) is the fabric filter on each silo.

The AC will be loaded into the silo through a pneumatic transfer system. Air displaced during the pneumatic transfer will exit through the fabric filter on the top of each silo. The maximum loading rate for each silo will be approximately 0.2 trucks/day (1 truck every 5 days) for S901 and S902 and approximately 0.3 trucks per day (1 truck every 3 days) for S903 and S904. It will take approximately 60 to 90 minutes to unload a truck. During truck unloading the maximum air flow will be 440 scfm. In addition to the displaced air during pneumatic transfer, there will be other intermittent air flow through the silos. Air is introduced into hoppers at the base of the silo to keep the AC fluidized and free flowing. The maximum flow rate for the fluidization system is 130 scfm. There will also be a small flow, 8 scfm, during the cleaning cycle of the pulse jet fabric filters. The maximum flow rate is 578 scfm, the sum of these individual flow rates. This maximum flow rate can occur only a short period (90 minutes every 3 or 5 days) and much of the time there will be no air flow through the silos. The emissions calculations given below, however, assume that the maximum air flow rate occurs continuously. This results in a large overestimate of annual emissions from the silos, but simplifies the emission calculation and potential compliance requirements

The silo vendor has calculated and specified that the fabric filter control device will achieve emission reductions equivalent to a maximum grain loading of 0.0092 grains of PM per standard cubic foot of exhaust gas. Using the maximum short-term gas flow rate of 578 scfm, the PM emission rate for each silo can be calculated as follows:

578 ft^3/min * 0.0092 grains/ft^3 * 1 lb/7,000 grains = 0.00076 lbs PM/min = 0.046 lbs/hr = 0.2 tpy at 8,760 hours per year.

The actual tpy emissions will be much lower than this value because the fabric filter exhaust flow rate is at the maximum flow rate a small fraction of the year.

For permitting purposes, we are assuming that all PM emissions are also PM10.

Based on particle size distribution data for activated carbon, PM2.5 makes up less than 5 percent of the activated carbon by volume. Therefore PM2.5 emissions have been estimates as follows assuming the same ratio in the controlled emissions:

PM2.5 = 0.05 * PM = 0.00228 lbs/hr = 0.0099864 tpy

On this basis, the controlled PTE emission rates for the silo exhaust units are as follows:

Emission Unit	PM/PM10 Maximum lb/hr (Controlled)	PM/PM10 Maximum tpy (Controlled)	PM2.5 Maximum lb/hr (Controlled)	PM2.5 Maximum tpy (Controlled)
E901 (Unit 1 AC silo vent)	0.046	0.2	0.0023	0.010
E902 (Unit 2 AC silo vent)	0.046	0.2	0.0023	0.010
E903 (Unit 3 AC silo vent)	0.046	0.2	0.0023	0.010
E904 (Unit 4 AC silo vent)	0.046	0.2	0.0023	0.010

Uncontrolled emission rates from the silo vents can be estimated by assuming that the 0.046 lb/hr estimate above is achieved through controls that are 99.9 percent efficient. Thus, without such controls"uncontrolled" PM/PM10 and 2.28 lbs/hr PM2.5 emissions would be approximately 46.0 lbs/hr per silo. The use of the term "uncontrolled" is purely theoretical and only provided for permitting purposes because, in practice an AC storage silo would never be operated with just an open top as valuable product would be lost and the stored material would be open to rain or other

environmental conditions that would interfere with the AC effectiveness. Note that 46.0 lbs/hr is approximately the average per unit AC injection rate for mercury control, which confirms the unrealistic nature of this value as clearly the silos would not release 100 percent of the AC received.

Alkaline Sorbent Storage Silo Bin Vents (Baghouses):

Scenario A:

Sorbent Storage Silo Bin Vents (Baghouses):

The sorbent used in the sorbent injection system will be stored in silos. There will be one silo for boiler Units 1/2 and one silo for boiler unit 3 and one silo for unit 4. Each silo will have a passive (i.e. no fan) fabric filter to control PM emissions from any air vented from the silos. These silos have been given source, emission and control unit numbers as follows:

SU520/S520/E520 – Units 1/2 sorbent silo
SU521/S521/E521 – Unit 3 sorbent silo
SU522/S522/E522 – Unit 4 sorbent silo

The "SU" numbers indicate the storage unit number, the "S" numbers indicate the source number and the "E" numbers indicate the emission source, which in this case are the bin vents on each silo.

The sorbent will be loaded into the silo through a pneumatic transfer system. Air displaced during the pneumatic transfer will exit through the fabric filter on the top of each silo. The maximum loading rate for each silo will be approximately 0.07 trucks/day (1 truck every 14 days) for SU520 and approximately 0.14 trucks per day (1 truck every 7 days) for SU521. Details of the pneumatic loading design have not been completed. It is reasonable to expect that air flow rates during truck unloading to the silos would be similar to the activated carbon silo loading. The total flow rate for an activated carbon silo during loading is 578 scfm. Using this value and a bin vent filter emission rate of 0.01 grains/scf (specification will be 0.005 gr/scf) gives:

578 ft^3/min * 0.01 grains/ft^3 * 1 lb/7,000 grains = 0.00082571 lbs PM/min = 0.0495 lbs/hr = 0.21681 tpy at 8,760 hours per year.

The actual tpy emissions will be <u>much lower</u> than this value because the fabric filter exhaust flow rate is at the maximum flow rate only when trucks are being unloaded into the silo – which is a very small fraction of the year..

For permitting purposes, we are assuming that all PM emissions are also PM10.

Typically bulk materials (such as lime, trona, sodium bicarbonate) contain only a small fraction of very fine (PM2.5) particles. Therefore, PM2.5 has been estimated using a 5 percent fine particle content (same as used for activated carbon) to give:

PM2.5 = 0.05 * PM = 0.002277 lbs/hr = 0.011tpy

On this basis, the PTE controlled emission rates for the silo exhaust units are as follows:

Emission Unit	PM/PM10 Maximum lb/hr (Controlled)	PM/PM10 Maximum tpy (Controlled)	PM2.5 Maximum lb/hr (Controlled)	PM2.5 Maximum tpy (Controlled)
E520 (Unit 1/2 sorbent silo vent)	0.050	0.22	0.0023	0.011
E521 (Unit 3 sorbent silo vent)	0.050	0.22	0.0023	0.011
E522 (Unit 4 sorbent silo vent)	0.050	0.22	0.0023	0.011

Uncontrolled emission rates from the silo vents can be estimated by assuming the 99.9 percent efficient. This is equivalent to 49.5 lbs/hr per silo of "uncontrolled" PM/PM10 (217 tpy) and 2.3 lbs/hr PM2.5 emissions (10 tpy). The use of the term "uncontrolled" is purely theoretical and only provided for permitting purposes because, in practice a DSI storage silo would never be operated with just an open top as valuable product would be lost and the stored material would be open to rain or other environmental conditions.

Section 7

Information Used To Determine Emissions

Information Used to Determine Emissions shall include the following:

- ☐ If manufacturer data are used, include specifications for emissions units and control equipment, including control efficiencies specifications and sufficient engineering data for verification of control equipment operation, including design drawings, test reports, and design parameters that affect normal operation.
- ☐ If test data are used, include a copy of the complete test report. If the test data are for an emissions unit other than the one being permitted, the emission units must be identical. Test data may not be used if any difference in operating conditions of the unit being permitted and the unit represented in the test report significantly effect emission rates.
- ☐ If the most current copy of AP-42 is used, reference the section and date located at the bottom of the page. Include a copy of the page containing the emissions factors, and clearly mark the factors used in the calculations.
- ☐ If an older version of AP-42 is used, include a complete copy of the section.
- ☐ If an EPA document or other material is referenced, include a complete copy.
- ☐ Fuel specifications sheet.
- ☐ If computer models are used to estimate emissions, include an input summary (if available) and a detailed report, and a disk containing the input file(s) used to run the model. For tank-flashing emissions, include a discussion of the method used to estimate tank-flashing emissions, relative thresholds (i.e., permit or major source (NSPS, PSD or Title V)), accuracy of the model, the input and output from simulation models and software, all calculations, documentation of any assumptions used, descriptions of sampling methods and conditions, copies of any lab sample analysis.

Cooling Tower Calculation Spreadsheet

San Juan Generating Station Cooling Tower PM Emission Calculations										
Emission Unit	Cooling Tower Name	Drift Rate %	Maximum Water Circulation Rate gpm	TDS mg/l	Liquid Drift gpm	TDS lbs/gal	Total Drift Solids lbs/hr	TSP Fraction	PM10 Fraction	PM2.5 Faction
E406	Unit 1	0.002	170,000	6,000	3.4000	0.05007	10.21507	1.0000	0.2351	0.00196
E407	Unit 2	0.002	165,000	6,000	3.3000	0.05007	9.91463	1.0000	0.2352	0.00196
E408	Unit 3	0.0015	220,000	3,900	3.3000	0.03255	6.44451	1.0000	0.366876	0.00196
E409	Unit 4	0.002	227,500	6,000	4.5500	0.05007	13.67017	1.0000	0.2351	0.00196
E410	Aux 1/Aux 2	0.002	35,000	3,900	0.7000	0.03255	1.36702	1.0000	0.366876	0.00196
Mass Drift Rates (total drift solids x size fraction factor)										
		TSP lbs/hr	**TSP tpy**	**PM10 lbs/hr**	**PM10 tpy**	**PM2.5 lbs/hr**	**PM2.5 tpy**			
E406	Unit 1	10.21507	44.7420	2.40156	10.5188	0.020022	0.0877			
E407	Unit 2	9.91463	43.4261	2.33192	10.2138	0.019433	0.0851			
E408	Unit 3	6.44451	28.2269	2.36433	10.3558	0.012631	0.0553			
E409	Unit 4	13.67017	59.8753	3.21386	14.0767	0.026794	0.1174			
E410	Aux 1/Aux 2	1.36702	5.9875	0.50153	2.1967	0.002679	0.0117			
TOTAL										
		41.6114	182.2579	10.8132	47.3618	0.08156	0.3572			

SJGS Cooling Tower PM10 and PM2.5 Calculation for TDS = 3,900 mg/l						
Rho = 2.2 g/cm3						
Droplet Diameter um	Droplet Volume (um)3	Droplet Mass ug	PM Mass ug	PM Volume (um)3	Solid Diameters um	Mass Fraction %
10	523.6	0.0005235852	2.041982E-006	0.928174	1.21026	0.00000
20	4188.7	0.0041886819	1.633586E-005	7.42539	2.42051	0.19600
30	14136.8	0.0141368016	5.513353E-005	25.0607	3.63077	0.22600
40	33509.5	0.0335094556	0.000130687	59.4031	4.84102	0.51400
50	65448.2	0.0654481554	0.000255248	116.022	6.05128	1.8160
60	113094.4	0.1130944126	0.000441068	200.486	7.26153	5.7020
70	179589.7	0.1795897385	0.000700400	318.364	8.47179	21.348
90	381693.6	0.3816936424	0.00148861	676.639	10.89230	48.812
110	696892.0	0.6968919589	0.00271788	1235.40	13.31281	70.509
130	1150316.8	1.1503167797	0.00448624	2039.20	15.73332	82.023
150	1767100.2	1.7671001964	0.00689169	3132.59	18.15383	88.012
180	3053549.1	3.0535491394	0.0119088	5413.11	21.78459	91.032
210	4848922.9	4.8489229389	0.0189108	8595.82	25.41536	92.468
240	7238042.4	7.2380424044	0.0282284	12831.1	29.04612	94.091
270	10305728.3	10.3057283454	0.0401923	18269.2	32.67689	94.689
300	14136801.6	14.1368015711	0.0551335	25060.7	36.30765	96.288
350	22448717.3	22.4487173097	0.0875500	39795.5	42.35893	97.011
400	33509455.6	33.509455576	0.130687	59403.1	48.41020	98.340
450	47711705.3	47.7117053025	0.186076	84579.8	54.46147	99.071
500	65448155.4	65.4481554219	0.255248	116022	60.51275	99.071
600	113094412.6	113.094412569	0.441068	200486	72.61530	100.000
Interpolate to get (10-8.47179)/(10.89230-8.47179)=					0.6313601074	38.6876739904
PM2.5 is less than 0.196 so use 0.196% as a conservative value						

SJGS Cooling Tower PM10 and PM2.5 Calculation for TDS = 6,000 mg/l						
Rho = 2.2 g/cm3						
Droplet Diameter um	Droplet Volume (um)3	Droplet Mass ug	PM Mass ug	PM Volume (um)3	Solid Diameters um	Mass Fraction %
10	523.6	0.0005235852	0.000003	1.42796	1.39714	0
20	4188.7	0.0041886819	0.000025	11.42368	2.79428	0.196
30	14136.8	0.0141368016	0.000085	38.55491	4.19141	0.226
40	33509.5	0.0335094556	0.000201	91.38942	5.58855	0.514
50	65448.2	0.0654481554	0.000393	178.49497	6.98569	1.816
60	113094.4	0.1130944126	0.000679	308.43931	8.38283	5.702
70	179589.7	0.1795897385	0.001078	489.79020	9.77996	21.348
90	381693.6	0.3816936424	0.002290	1040.98266	12.57424	48.812
110	696892.0	0.6968919589	0.004181	1900.61443	15.36851	70.509
130	1150316.8	1.1503167797	0.006902	3137.22758	18.16279	82.023
150	1767100.2	1.7671001964	0.010603	4819.36417	20.95706	88.012
180	3053549.1	3.0535491394	0.018321	8327.86129	25.14847	91.032
210	4848922.9	4.8489229389	0.029094	13224.33529	29.33989	92.468
240	7238042.4	7.2380424044	0.043428	19740.11565	33.53130	94.091
270	10305728.3	10.3057283454	0.061834	28106.53185	37.72271	94.689
300	14136801.6	14.1368015711	0.084821	38554.91338	41.91412	96.288
350	22448717.3	22.4487173097	0.134692	61223.77448	48.89981	97.011
400	33509455.6	33.509455576	0.201057	91389.42430	55.88549	98.34
450	47711705.3	47.7117053025	0.286270	130122.83264	62.87118	99.071
500	65448155.4	65.4481554219	0.392689	178494.96933	69.85686	99.071
600	113094412.6	113.094412569	0.678566	308439.30701	83.82824	100
At 10 um the fraction is (10-9.7799)/(12.574-9.7799) =					0.07877	23.51133928
PM2.5 is less than 0.196 so use 0.196% as a conservative value						

Scenario A

Paved Road Emission Calculation Spreadsheet

Route	Empty Weight tons	Load weight tons	Mean Weight tons	Trucks/Yr	VMT/Yr	Weight * VMT
Unit 1 & 2 FA Paved	47.5	65	80	11198	5219.5	417563.2
Unit 3 & 4 FA Paved	47.5	65	80	17266	9674.5	773956.6
Limestone Paved	15	22	26	5235	12273.6	319113.7
Unit 1 & 2 FO	15	26.25	28.125	219	602.0	16931.8
Unit 3 & 4 FO	15	26.25	28.125	329	772.7	21732.7
Unit 1 & 2 Sorbent	15	22	26	52	140.7	3659.3
Unit 3 & 4 Sorbent	15	22	26	104	257.5	6694.5
Unit 1 & 2 Activated Carbon	15	22	26	152	411.4	10696.5
Unit 3 & 4 Activated Carbon	15	22	26	234	579.3	15062.7
Unit 1 & 2 Ammonia	15	26.25	28.125	312	844.5	23750.5
Unit 3 & 4 Ammonia	15	26.25	28.125	416	1029.9	28966.7
Unit 1 & 2 Sulfuric Acid	15	26.25	28.125	57	156.7	4406.9
Unit 3 & 4 Sulfuric Acid	15	26.25	28.125	84	223.9	6298.0
Unit 1 & 2 CT Bleach	15	26.25	28.125	15	41.2	1159.7
Unit 3 & 4 CT Bleach	15	26.25	28.125	22	58.6	1649.5
Unit 1 & 2 CT Inhibator	15	26.25	28.125	8	22.0	618.5
Unit 3 & 4 CT Inhibitor	15	26.25	28.125	12	32.0	899.7
Unit 1 & 2 Sodium Hydroxide	15	26.25	28.125	1	2.7	76.1
Unit 3 & 4 Sodium Hydroxide	15	26.25	28.125	1	2.5	69.6
Unit 1 & 2 Hydrogen	15	22	26	18	48.7	1266.7

Unit 3 & 4 Hydrogen	15	22	26	27	66.8	1738.0
Unit 1 & 2 CO2	15	22	26	4	10.8	281.5
Unit 3 & 4 CO2	15	22	26	5	12.4	321.9
Unit 1 & 2 CT Versene	15	22	26	1	2.7	71.5
Unit 3 & 4 CT Versene	15	22	26	2	5.3	138.6
Super Sucker	0	0	20	365	103.5	2070.4
Unit 1 & 2 CT Lime	15	22	26	15	41.2	1072.1
Unit 3 & 4 CT Lime	15	22	26	22	58.6	1524.8
DBA Delivery	15	22	26	126	295.4	7680.7
Front End Loader Paved	0	0	16	0	1950.0	31200.0
Sludge Trucks	0	0	20	0	2600.0	52000.0
Cranes	0	0	20	0	500.0	10000.0
Forklifts	0	0	10	0	38480.0	384800.0
Bobcats	0	0	5	0	600.0	3000.0
Dump Trucks	0	0	15	0	260.0	3900.0
Tractor trailer	0	0	15	0	150.0	2250.0
Pickup Paved	0	0	2.5	0	43295.0	108237.5
Vacuum Truck Paved	0	0	20	0	12656.0	253120.0
					133482.0	2517980.1
					Normalized Weight	18.9
Uncontrolled Hourly	lbs/hr = k(sL)^0.91 x (w)^1.02 * VMT/8760					
Uncontrolled Annual	tons/yr = k(sL)^0.91 x (w)^1.02 * (1-P/4N) * VMT / 2000					
Controlled Hourly	lbs/hr = k(sL)^0.91 x (w)^1.02 * (1-%CE) * VMT/8760					
Controlled Annual	ton/yr = k(sL)^0.91 x (w)^1.02 * (1-%CE) * (1-P/4N) * VMT / 2000					
	TSP	**PM10**	**PM2.5**			
sL	9.7	9.7	9.7			
k	0.011	0.0022	0.00054			
w	18.9	18.9	18.9			
P	65	65	65			
N	365	365	365			

%CE	38%	38%	38%			
VMT	133482.0	133482.0	133482.0			
Uncontrolled Hourly (lbs/hr)	26.51	5.30	1.30			
Uncontrolled Annual (tpy)	110.95	22.19	5.45			
Controlled Hourly (lbs/hr)	16.44	3.29	0.81			
Controlled Annual (tpy)	68.79	13.76	3.38			

Scenario B

Paved Road Emission Calculation Spreadsheet

Route	Empty Weight tons	Load weight tons	Mean Weight tons	Trucks/Yr	VMT/Yr	Weight * VMT
Unit 1 & 2 FA Paved	47.5	65	80	11198	5219.5	417563.2
Unit 3 & 4 FA Paved	47.5	65	80	17266	9674.5	773956.6
Limestone Paved	15	22	26	5235	12273.6	319113.7
Unit 1 & 2 FO	15	26.25	28.125	219	602.0	16931.8
Unit 3 & 4 FO	15	26.25	28.125	329	772.7	21732.7
Unit 1 & 2 Sorbent	15	22	26	0	0	0
Unit 3 & 4 Sorbent	15	22	26	0	0	0
Unit 1 & 2 Activated Carbon	15	22	26	152	411.4	10696.5
Unit 3 & 4 Activated Carbon	15	22	26	234	579.3	15062.7
Unit 1 & 2 Urea	15	22	26	474.5	1284.3	33391.5
Unit 3 & 4 Urea	15	22	26	766.5	1897.7	49339.9
Unit 1 & 2 Sulfuric Acid	15	26.25	28.125	57	156.7	4406.9
Unit 3 & 4 Sulfuric Acid	15	26.25	28.125	84	223.9	6298.0
Unit 1 & 2 CT Bleach	15	26.25	28.125	15	41.2	1159.7
Unit 3 & 4 CT Bleach	15	26.25	28.125	22	58.6	1649.5
Unit 1 & 2 CT Inhibator	15	26.25	28.125	8	22.0	618.5
Unit 3 & 4 CT Inhibitor	15	26.25	28.125	12	32.0	899.7
Unit 1 & 2 Sodium Hydroxide	15	26.25	28.125	1	2.7	76.1
Unit 3 & 4 Sodium Hydroxide	15	26.25	28.125	1	2.5	69.6
Unit 1 & 2 Hydrogen	15	22	26	18	48.7	1266.7
Unit 3 & 4 Hydrogen	15	22	26	27	66.8	1738.0

Unit 1 & 2 CO2	15	22	26	4	10.8	281.5
Unit 3 & 4 CO2	15	22	26	5	12.4	321.9
Unit 1 & 2 CT Versene	15	22	26	1	2.7	71.5
Unit 3 & 4 CT Versene	15	22	26	2	5.3	138.6
Super Sucker	0	0	20	365	103.5	2070.4
Unit 1 & 2 CT Lime	15	22	26	15	41.2	1072.1
Unit 3 & 4 CT Lime	15	22	26	22	58.6	1524.8
DBA Delivery	15	22	26	126	295.4	7680.7
Front End Loader Paved	0	0	16	0	1950.0	31200.0
Sludge Trucks	0	0	20	0	2600.0	52000.0
Cranes	0	0	20	0	500.0	10000.0
Forklifts	0	0	10	0	38480.0	384800.0
Bobcats	0	0	5	0	600.0	3000.0
Dump Trucks	0	0	15	0	260.0	3900.0
Tractor trailer	0	0	15	0	150.0	2250.0
Pickup Paved	0	0	2.5	0	43295.0	108237.5
Vacuum Truck Paved	0	0	20	0	12656.0	253120.0
					133560.3	2516031.0
					Normalized Weight	18.8
Uncontrolled Hourly	lbs/hr = k(sL)^0.91 x (w)^1.02 * VMT/8760					
Uncontrolled Annual	tons/yr = k(sL)^0.91 x (w)^1.02 * (1-P/4N) * VMT / 2000					
Controlled Hourly	lbs/hr = k(sL)^0.91 x (w)^1.02 * (1-%CE) * VMT/8760					
Controlled Annual	ton/yr = k(sL)^0.91 x (w)^1.02 * (1-%CE) * (1-P/4N) * VMT / 2000					
	TSP	**PM10**	**PM2.5**			
sL	9.7	9.7	9.7			
k	0.011	0.0022	0.00054			
w	18.8	18.8	18.8			
P	65	65	65			
N	365	365	365			
%CE	38%	38%	38%			
VMT	133560.3	133560.3	133560.3			

Uncontrolled Hourly (lbs/hr)	26.49	5.30	1.30			
Uncontrolled Annual (tpy)	110.86	22.17	5.44			
Controlled Hourly (lbs/hr)	16.42	3.28	0.81			
Controlled Annual (tpy)	68.73	13.75	3.37			

Section 8

Map(s)

A map such as a 7.5 minute topographic quadrangle showing the exact location of the source. The map shall also include the following:

The UTM or Longitudinal coordinate system on both axes	An indicator showing which direction is north
A minimum radius around the plant of 0.8km (0.5 miles)	Access and haul roads
Topographic features of the area	Facility property boundaries
The name of the map	The area which will be restricted to public access
A graphical scale	

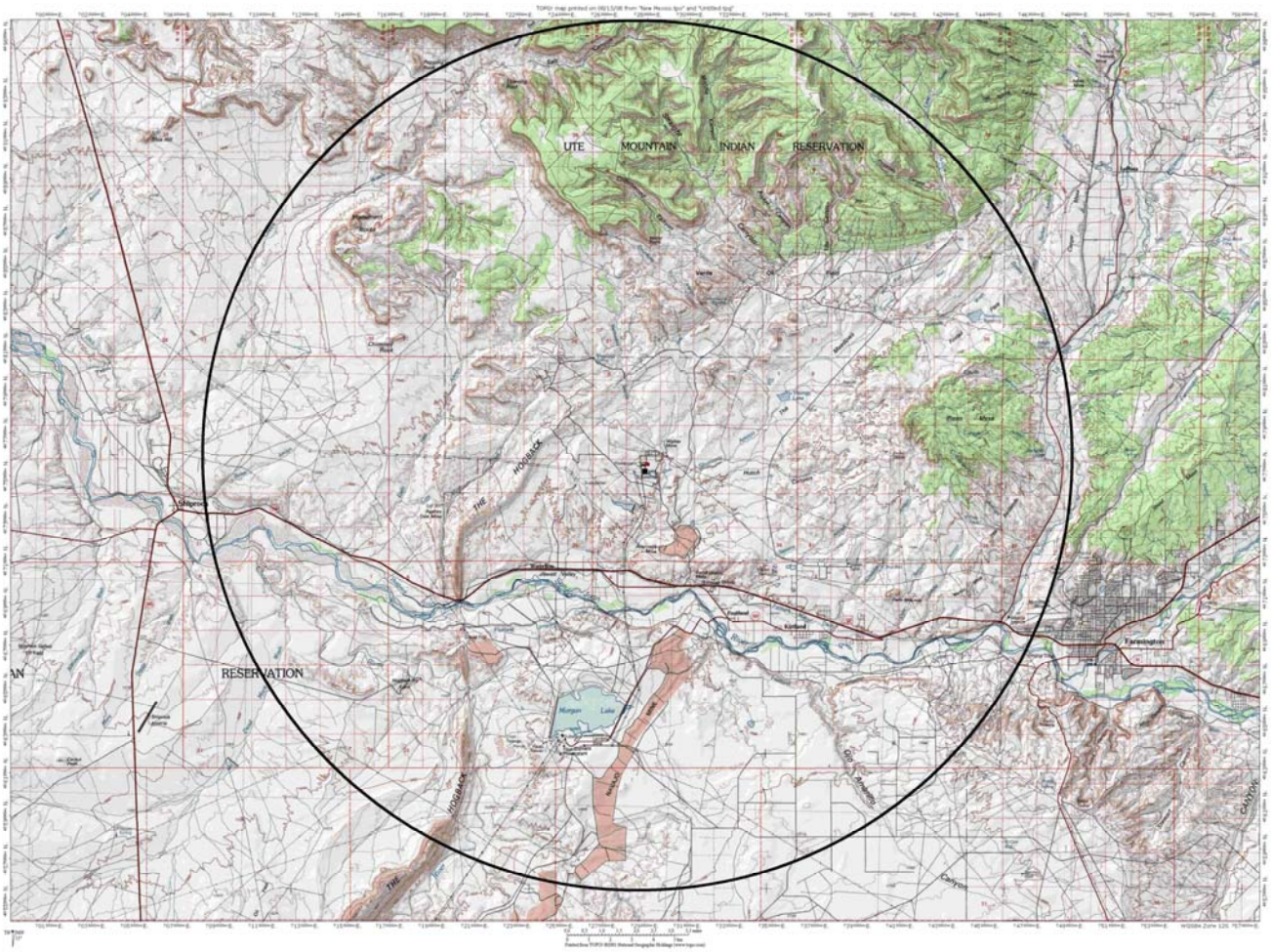


FIGURE 9-1 10-Mile Radius

Section 9

Proof of Public Notice

(for NSR applications submitting under 20.2.72 or 20.2.74 NMAC)
(This proof is required by: 20.2.72.203.A.14 NMAC "Documentary Proof of applicant's public notice")

☐ **I have read the AQB "Guidelines for Public Notification for Air Quality Permit Applications"**
This document provides detailed instructions about public notice requirements for various permitting actions. It also provides public notice examples and certification forms. Material mistakes in the public notice will require a re-notice before issuance of the permit.

Unless otherwise allowed elsewhere in this document, the following items document proof of the applicant's Public Notification. Please include this page in your proof of public notice submittal with checkmarks indicating which documents are being submitted with the application.

New Permit and **Significant Permit Revision** public notices must include all items in this list.

Technical Revision public notices require only items 1, 5, 9, and 10.

Per the Guidelines for Public Notification document mentioned above, include:

1. **X** A copy of the certified letter receipts with post marks (20.2.72.203.B NMAC)
2. **X** A list of the places where the public notice has been posted in at least four publicly accessible and conspicuous places, including the proposed or existing facility entrance. (e.g: post office, library, grocery, etc.)
3. **X** A copy of the property tax record (20.2.72.203.B NMAC).
4. **X** A sample of the letters sent to the owners of record.
5. **X** A sample of the letters sent to counties, municipalities, and Indian tribes.
6. **X** A sample of the public notice posted and a verification of the local postings.
7. **X** A table of the noticed citizens, counties, municipalities and tribes and to whom the notices were sent in each group.
8. **X** A copy of the public service announcement (PSA) sent to a local radio station and documentary proof of submittal.
9. **X** A copy of the classified or legal ad including the page header (date and newspaper title) or its affidavit of publication stating the ad date, and a copy of the ad. When appropriate, this ad shall be printed in both English and Spanish.
10. **X** A copy of the display ad including the page header (date and newspaper title) or its affidavit of publication stating the ad date, and a copy of the ad. When appropriate, this ad shall be printed in both English and Spanish.
11. **X** A map with a graphic scale showing the facility boundary and the surrounding area in which owners of record were notified by mail. This is necessary for verification that the correct facility boundary was used in determining distance for notifying land owners of record.

See Attachment A-0063-9-PublicNotice for public notice documentation. See Attachment A-0063-9-BndryMap for facility boundary/surrounding area information.

Section 10

Written Description of the Routine Operations of the Facility

---

A written description of the routine operations of the facility. Include a description of how each piece of equipment will be operated, how controls will be used, and the fate of both the products and waste generated. For modifications and/or revisions, explain how the changes will affect the existing process. In a separate paragraph describe the major process bottlenecks that limit production. The purpose of this description is to provide sufficient information about plant operations for the permit writer to determine appropriate emission sources.

This permit application is for construction of one of two Scenarios. Scenario A is Selective Catalytic Reduction (SCR) NOx controls on each of the four boiler units at SJGS in an effort to comply with the new NOx emission limits required in the SJGS FIP published in 40 C.F.R. Part 52 Subpart GG. Although the emission limits required by the FIP become effective no later than five years after the effective date of the rule, installation of the SCRs, along with associated facilities and equipment, will require significant time for planning, design, procurement, construction, start-up, and testing prior to completion of the project. Obtaining a timely authority to construct permit under 20.2.72NMAC is essential to meeting the compliance deadlines established in the FIP. Scenario B is Selective Non-Catalytic Reduction (SNCR) NOx controls on each of the four boiler units at SJGS to comply with NOx emission limits required by the SJGS SIP adopted pursuant to section 309 of the federal Clean Air Act, which specifies controls for SJGS that are different than the FIP. If the judicial review of the FIP results in vacatur of the FIP requirements, PNM would implement the SIP requirements which require installation and operation of an SNCR control system, rather than SCR.

The San Juan Generating Station (SJGS) is a four-unit coal fired electric steam generating facility. Each unit consists of a pulverized coal, wall fired, dry bottom boiler. Foster Wheeler manufactured the Unit 1 and 2 boilers and Babcock and Wilcox manufactured the Unit 3 and 4 boilers. Unit 2 was constructed first, followed by units 1,3 and 4. The units are numbered from south to north. Unit 1 is the furthest south.

The current coal source for SJGS is the nearby BHP Billiton San Juan Coal Company's San Juan Mine. All current and foreseeable mining at the San Juan Coal Mine is underground. The maximum SJGS annual coal usage (all four units combined) is 8,200,000 tons.

Coal from the San Juan Mine is delivered to SJGS by conveyor. From the main delivery point, coal is distributed by conveyors to the individual units, pulverized and sent to the boilers for combustion. Heat from the combustion process is used to produce superheated steam, which in turn drives steam turbines on each unit. Units 1,3 and 4 have General Electric turbines and unit 2 has a Westinghouse turbine. The nominal gross generating capacity for each turbine is:

Unit 1: 370 MW
Unit 2: 370 MW
Unit 3: 560 MW
Unit 4: 560 MW

The nominal, gross station-wide electrical production capacity is 1,860 MW.

Like all coal-fired generating stations, numerous subsystems, in addition to the boilers, are required. For SJGS permit applications, emission sources (identified with an S) and emission points (identified with an E) have been labeled with 3 digit numbers grouped as follows:

1. Coal handling (100-199)
2. Coal pulverizers (200-299)
3 Boilers with associated emissions controls (300-399)
4. Water Treatment and Cooling Towers (400-499)
5. Ash Handling and Dry Sorbent Injection (500-599)
6. Emergency Generators (600-699, all are insignificant emission sources)
7. Vehicle Travel, Road Dust, Pile Maintenance (700-799)
8. Limestone/Gypsum Handling and Processing (800-899)
9. Activated Carbon Injection System (900-999)

1. Coal Handling: The San Juan Mine delivers coal to SJGS by conveyor to a transfer house. SJSG load-in stackers then distribute the coal to one of four coal piles. Coal from the piles is "reclaimed" through underground reclaimers below each pile which feeds conveyors that send coal to the unit coal silos (4 silos each for Units 1 and 2, 6 silos each for Units 3 and 4). The silos feed the coal pulverizers by gravity feed. Emission sources associated with coal supply/handling activities include fugitive dust from coal transfer points. Emission controls include chemical dust suppression systems and enclosures. The significant emission points are indicated on the drawings included in Section 4 and the detailed emission calculations and control assumptions are given in Section 6.

2. Coal Pulverizers: The coal pulverizers are a type of tertiary crusher that grinds coal to the required size for injection into the boiler furnace. Each unit has several identical pulverizers (4 each on Units 1 and 2 and 6 each on Units 3 and 4). Because the pulverizers are essentially identical, they have been identified in this permit application as a single line entry. Fugitive dust produced by the pulverizers is inherently limited because the pulverizers are a sealed system. Also, the pulverizers are located within the powerblock building, which acts as an enclosure to control any fugitive dust that may be produced. Emission calculations for the pulverizers are given in Section 6.

3. Boiler and combustion emission control system: The general process flow is essentially identical for each of the four SJGS boilers. Coal from the pulverizers is injected, along with combustion air, into the furnace section of the boiler through a series of burners. Additional air is injected at other locations in the furnace to control the combustion process. The formation of nitrogen oxides during the combustion process is limited through inherent design of the burners (low-NOx burner design) and control of combustion/temperature profile through design of the combustion air system. SJGS boilers include low-NOx burners and use of over-fired air (OFA) to limit the production of NOx during the combustion process.

   Scenario A: The Senario A permit application will allow the construction of NOx removal equipment (SCR) on each boiler unit. The SCR system will reduce flue gas NOx formed during the combustion process by chemical reaction of the NOx with ammonia in the presence of a catalyst. The SJGS SCR systems will use anhydrous ammonia delivered to the site by truck. Trucks will be unloaded to on-site storage tanks (one for Units 1/2 and one each for Units 3 and 4). The trucks, transfer systems and storage tanks are pressurized and non-vented and will not be a source of ammonia emissions. A small amount of the ammonia fed to the SCR reaction catalyst does not completely react and exits with the flue gas as "ammonia slip". The SJGS SCR units will

be designed to meet the 2 ppm ammonia slip limit set forth in the FIP, although. ammonia slip will usually be significantly less than 2 ppm.

The SCR catalyst must be periodically replaced because the catalyst activity deteriorates with time due to fouling of the catalyst beds. The exact schedule for catalyst replacement will depend on operational conditions and experience. The preliminary SCR design estimates that the SJGS catalyst beds will be replaced approximately every 17,000 hours of operation but actual replacement time will be based on operational measurement and experience to insure the catalyst beds are replaced prior to problems with meeting the NOx emission limit..

The catalytic reactions which convert ammonia and NOx to nitrogen and water occur only when the catalyst temperature has reached at least 580 degrees F. Therefore ammonia is not injected and NOx reduction will not occur during unit start-up until the catalyst warms to this minimum operating temperature. The time required to reach this temperature depends on a variety of factors including how much the catalyst bed has cooled down from previous operations. From a "cold start" where the catalyst bed is at ambient temperature, the time period to reach the minimum catalyst operating temperature is estimated to be as long as 20 hours. Start-up times for "hot" or "warm" starts would be proportionally less depending on the exact temperature of the bed at time of the start-up.

Scenario B: The Scenario B permit application will allow the construction of NOx removal equipment (SNCR) on each boiler unit. The SNCR system will reduce flue gas NOx formed during the combustion process by chemical reaction of the NOx with urea (in water solution) injected into the boiler. Several boiler injection points are used to insure the most efficient distribution of the urea and to be able to respond to changes in boiler load, temperature and chemistry profiles. The urea produces ammonia within the boiler, which reacts with NOx converting the NOx to N_2. Urea will be delivered by tank trucks, which will be unloaded to on-site storage tanks (one for Units 1/2 and one for Units 3 /4). The urea solution unloading and storage is not a source of air emissions. A small amount ammonia produced by the urea in the the boiler does not completely react with NO and exits with the flue gas as ammonia. This ammonia is called "ammonia slip". Ammonia slip for the SJGS SNCR units will not exceed 10 ppm by volume in the stack exit flue gas and will typically be less (approximately 5 ppm).

Thermal energy produced by the combustion process is recovered in a heat exchanger system (boiler tubes) that produce high pressure superheated steam to drive the steam turbines/electrical generators. Because of the high temperatures and pressures, the water circulated through the boiler tubes to produce superheated steam must be treated to produce water of acceptable quality. This high quality water is condensed and recycled back to the boilers.

Non-combustible particulate matter (PM) in the coal (ash) is a by-product of the coal combustion process. Some of the ash (approximately 20 percent) drops out in the boiler and becomes bottom ash. The remainder is entrained in the combustion gases and exits the boiler as "fly ash." SJGS has fabric filters (baghouses) on the boiler units to control fly ash emissions.. These fabric filters replaced the previous electrostatic precipitators (ESPs) as the primary PM control system. The previously used ESP's have been left in place, but are de-energized. Some ash collects in the bottom of the de-energized ESPs through gravitational settling.

For permitting scenario A, new ash hoppers will be installed at the boiler economizer outlets. These hoppers collect ash that gravitationally settle in this section of the ducts. The ash collected by the new economizer ash system will be pneumatically transferred to the existing ash silos. The

new economizer ash handling system will be sealed and will not create any new emission sources. The existing ash storage silos are controlled with fabric filters (bin vents).

Scenario A: For the Scenario A permit revision, ducts will be installed that bypass the ESP structure, eliminating the gravitational settling in the ESP structure, and fly ash will no longer be collected from ESP bottom fly ash hoppers.

Scenario B: For the Scenario B permit revision, flue gas will continue to pass through the de-energized ESP structure, and fly ash that gravitationally settles within the ESP structure will continue to be removed from the ESP fly ash hoppers.

The proposed fly ash handling changes do not change the total amount of fly ash handled and do not change the air emissions of fly ash due to fly ash handling operations.

The boiler fabric filters (baghouses) are in operation at all times the boiler units are in operation. A built-in bag cleaning system automatically cleans the filter bags without the need to take the entire baghouse off-line. The baghouse is divided into compartments that can be isolated to allow bags to be replaced without taking the entire baghouse off-line. Proper functioning of the fabric filters will be determined by continuous monitoring of the differential pressure across the baghouse and by continuous monitoring the opacity (COMS) of the gas stream exiting the baghouse.

Each of the boiler units includes an activated carbon injection system for control of mercury emissions. The system consists of activated carbon delivery by truck, storage silos, (one per unit), and injection systems (one per unit) for injecting granular activated carbon into the combustion gases upstream of the baghouse. The activated carbon is intended to enhance mercury removal beyond that which occurs in the baghouse through absorption of mercury onto the activated carbon grains. The injected activated carbon is then removed from the gas stream, along with other particulate matter, by the particulate matter control system.

Combustion gases exiting the fabric filters are then sent through a limestone scrubber system to remove sulfur dioxide. The limestone scrubber system consists of a set of absorbers operated in parallel (3 per unit), which contact the combustion gases with limestone slurry. Chemical reaction of SO_2 and the limestone forms hydrated $CaSO_4$ (gypsum), which is removed from the scrubbers for disposal along with the ash. Absorbing enhancement agents, mixtures that are generally referred to as di-basic acid, may also be added to the limestone slurry to aide in efficient reaction of the SO_2 and limestone. The cleaned combustion gases exit the scrubbers through a demister in each absorber, which helps remove entrained droplets of absorber solution. Each boiler unit has a continuous SO_2 CEMS system on the exit stack downstream of the limestone scrubbers to insure proper functioning of the limestone scrubber system is maintained. Each boiler unit also has an inlet SO_2 CEMS monitor to allow determination of the percent SO_2 removal across the scrubber.

Scenario A: The SJGS FIP includes emission limits for sulfuric acid. Sulfuric acid may be created during the combustion process and the SCR unit may oxidize some SO_2 to SO_3/H_2SO_4. It is difficult to quantify the formation of sulfuric acid and the subsequent removal of sulfuric acid by condensation on equipment surfaces and removal in downstream control equipment (such as the limestone scrubber). This permit application proposes to install a dry sorbent injection (DSI) system that will allow use of various dry powdered sorbent materials to supply additional sulfuric acid control, as needed, in an effort to meet the FIP sulfuric acid emission limit. The dry sorbent

(trona, sodium bicarbonate or lime) will be delivered to SJGS by truck and pneumatically transferred to storage silos, with one silo for units 1 and 2 and one silo for unit 3 and one silo for unit 4. The storage silos will be equipped with bin vent filters to control emissions from transfer to the silos. The rest of the transfer system is a sealed pneumatic system with no other emission points.

Emission calculations for the boiler combustion gas streams for each unit are given in detail in Section 6.

4. Water Treatment/Cooling Towers: Raw water for use at SJGS is obtained from the San Juan River, approximately 3.5 miles southeast of SJGS. Raw water from the river is pumped to a raw water reservoir near the plant. SJGS has a complex processing system for boiler water, cooling water and other water treatment to produce water with the required quality and properties. This water treatment system includes systems for treating and recycling water and for disposal of wastewater streams. The cooling towers are the only water system process equipment or operations that are potentially a significant air emissions source. Indirect contact heat exchangers are used to condense the steam exiting the steam turbines into the liquid phase to allow recycling back to the boilers. The heat transferred from the steam to the cooling water heats the cooling water, which in turn must be cooled to allow it to be re-used as cooling water. The cooling water is cooled through evaporative cooling in a cooling tower. Efficient evaporation is achieved by contacting the cooling water with ambient air in a cooling tower. This process produced some liquid water droplets which may exit the tower (drift losses) and carry with them dissolved solids (TDS). If these droplets evaporate before they deposit to the ground, the dissolved solids left behind create fugitive particulate matter. The cooling towers at SJGS must operate whenever the boiler units are operating. The amount of cooling tower drift is minimized through cooling tower design which includes “drift eliminators” to minimize the quantity of drift formed. Emission calculations for each cooling tower are given in detail in Section 6. The emission calculations for the application have been updated to provide more realistic calculations of the PM10 and PM2.5 PM size fractions.

5. Ash Handling: Non-combustible material in the coal (ash) is collected at the bottom of the boilers (bottom ash), from the new economizer ash collection system (as described above) and from the fabric filters. Water is used to flush bottom ash accumulated in the boilers into ash hoppers and high-pressure pumps are then used to convey the bottom ash to dewatering bins. Fly Ash from the economizer ash hoppers is also conveyed to the bottom ash dewatering bins. Dewatered bottom ash is loaded directly into trucks, which transport the bottom ash to the adjacent San Juan Mine for disposal. Dry fly ash from the boiler fabric filters (baghouses) is conveyed pneumatically to fly ash storage silos (one per boiler unit). Air vented from the silos during silo loading process exits the silos through a fabric filter baghouse (bin vent filter) on each silo. Differential pressure sensors on each ash silo baghouse are monitored to insure proper functioning of these filters. A portion of the fly ash collected is sent to a Salt River Materials Group (SRMG) fly ash recycling facility, co-located at SJGS and operating under a separate air quality permit. SRMG processes the fly ash and transports the processed fly ash off-site for use in various aggregate, construction and building materials. Ash transfer to the trucks is a potential source of fugitive dust emissions. The portion of the fly ash that cannot be recycled for use is transferred (at each fly ash silo) into trucks that transport the fly ash to the San Juan Mine for disposal.

   Emission calculations for ash handling are given in detail in Section 6.

6. Emergency Generators: SJGS has several emergency generators (one for each boiler unit and one at the electrical switchyard) to provide power to those loads that are necessary for protection of equipment and personnel during a total loss of station and off-site power. These generators operate for less than 500 hours per year (including periodic testing) and are therefore insignificant emission sources.

7. Vehicle Travel, Pile Maintenance: Vehicle travel on both paved and unpaved roads has the potential to produce fugitive dust emissions. Vehicles, such as front-end loaders, used to maintain coal and limestone piles may also produce fugitive dust. Vehicle travel includes travel on haul roads used to transport ash and gypsum to the San Juan Mine for disposal. Other vehicle traffic includes truck delivery of limestone and activated carbon and a variety of light and medium duty transport and maintenance vehicles that operate on both paved and unpaved roads. A detailed listing of the vehicle categories along with estimates of annual VMT (vehicle miles traveled for each category) is given in Section 6.

8. Limestone and Gypsum Handling: Limestone used to make the limestone slurry for the SO_2 absorbers is delivered to SJGS by truck. The trucks deliver the limestone (which has been crushed prior to delivery) to a limestone pile or directly to a hopper. The hopper feeds a conveyor which transports the limestone to a silo. Air from the silo is vented through a fabric filter (baghouse). The differential pressure across the limestone silo baghouse is monitored to insure proper functioning of the baghouse. From the silo, limestone drops onto a weigh belts, is mixed with water and sent to a ball mill where it is processed into slurry to be sent to the absorbers. The limestone transfer operations at the pile, hopper and weigh belt can potentially produce fugitive dust.

   The reacted limestone (gypsum) from the absorbers is dewatered and sent to a gypsum storage pile. Gypsum from the pile is loaded into trucks by front-end loader and the trucks transport the gypsum to the San Juan Mine for disposal.

   Detailed emission calculations for these emission sources are given in Section 6.

9. Activated Carbon Injection System: The activated carbon injection (ACI) system is used to inject activated carbon into the boiler combustion gas stream ahead of the boiler fabric filters to control mercury emissions. Activated carbon is delivered to SJGS by truck. The activated carbon is loaded into storage silos (one for each boiler unit) pneumatically. Each storage silo is equipped with a fabric filter (baghouse) to control PM from air venting from the silo. The differential pressure across each baghouse is monitored to insure proper functioning of the baghouse. Following each silo is an injection system that pneumatically injects the granular activated carbon into the ahead of the boiler fabric filters. The quantity of activated carbon injected is a very small fraction of the total PM load to the boiler fabric filters that remove the activated carbon from the combustion gases at the same time it removes fly ash. The used activated carbon is transported, along with the fly ash, to the adjacent San Juan Mine for disposal.

Process Bottlenecks:

The overall design of the boilers, steam production/heat rejection systems and the systems that deliver fuel to the boilers are the limiting factors on the amount of coal that can be combusted at SJGS. The maximum amount of coal that can be combusted at each unit is:

Unit 1: 1,600,000 tpy
Unit 2: 1,600,000 tpy
Unit 3: 2,500,000 tpy
Unit 4: 2,500,000 tpy

Section 11

Source Determination

Source submitting under 20.2.70, 20.2.72, and 20.2.74 NMAC

Sources applying for a construction permit, PSD permit, or operating permit shall evaluate surrounding and/or associated sources (including those sources directly connected to this source for business reasons) and complete this section. Responses to the following questions shall be consistent with the Air Quality Bureau's permitting guidance, Single Source Determination Guidance, which may be found on the Applications Page in the Permitting Section of the Air Quality Bureau website.

Typically, buildings, structures, installations, or facilities that have the same SIC code, that are under common ownership or control, and that are contiguous or adjacent constitute a single stationary source for 20.2.70, 20.2.72, and 20.2.74 NMAC applicability purposes. Submission of your analysis of these factors in support of the responses below is optional, unless requested by NMED.

A. Identify the emission sources evaluated in this section (list and describe)**:**

- Public Service Company of New Mexico, San Juan Generating Station
- BHP Billiton's San Juan Coal Company, San Juan Coal Mine

B. Apply the 3 criteria for determining a single source:

SIC Code: Surrounding or associated sources belong to the same 2-digit industrial grouping (2-digit SIC code) as this facility, OR surrounding or associated sources that belong to different 2-digit SIC codes are support facilities for this source.

X Yes ☐ **No**

Common Ownership or Control: Surrounding or associated sources are under common ownership or control as this source.

☐ **Yes** **X No**

Contiguous or Adjacent: Surrounding or associated sources are contiguous or adjacent with this source.

X Yes ☐ **No**

C. Make a determination:

X The source, as described in this application, constitutes the entire source for 20.2.70, 20.2.72, or 20.2.74 NMAC applicability purposes. If in "A" above you evaluated only the source that is the subject of this application, all "**YES**" boxes should be checked. If in "A" above you evaluated other sources as well, you must check **AT LEAST ONE** of the boxes "**NO**" to conclude that the source, as described in the application, is the entire source for 20.2.70, 20.2.72, and 20.2.74 NMAC applicability purposes.

☐ The source, as described in this application, **does not** constitute the entire source for 20.2.70, 20.2.72, or 20.2.74 NMAC applicability purposes (A permit may be issued for a portion of a source). The entire source consists of the following facilities or emissions sources (list and describe):

Although the San Juan Generating Station (Plant) and the San Juan Coal Mine (Mine) are located on contiguous properties, and although the Mine could be considered to be a "support facility" for the Plant, the Plant and the Mine are not under "common control," and therefore constitute separate major stationary sources under the Clean Air Act, the New Mexico Air Quality Control Act, and the federal and state regulations implementing those statutes. As requested by NMED, the following provides a thorough review of the source determination analysis for the San Juan Generating Station.

A. Regulatory Background & EPA Guidance

The New Mexico regulations define a "major source" to include the following:

> [A]ny stationary source (or any group of stationary sources that are located on one or more **contiguous or adjacent** properties, and are under **common control of the same person(s))** in which all of the pollutant emitting activities at such source belong to the **same major group** (i.e., all have the same two-digit code), as described in the standard industrial classification [SIC] manual, 1987. 20.2.70.7 NMAC.

Based on this regulatory provision, there are three key factors to consider in determining whether to aggregate multiple facilities into a single source:

(1) Are the facilities contiguous or adjacent?

(2) Are the facilities under common control of the same person(s)?

(3) Do the activities belong to the same industrial group or have the same SIC code?

EPA has consistently stated that the three regulatory criteria – "common control," "contiguous and adjacent," and "same industrial group" – should be analyzed on a case-by-case, fact-specific basis.[1] Each facility or group of facilities must be considered individually, and any prior source determinations, though perhaps helpful to consider as examples, will not control the outcome in other circumstances.[2] EPA guidance also confirms that facilities should not be aggregated unless they meet all three of the above criteria, with no single factor controlling the determination. Given that its regulatory analysis should achieve a "common sense" result, EPA has also considered whether allowing multiple sources would already qualify as a "major sources" individually, regardless of whether they were aggregated.[3] Similar reasoning has also led to the consideration of practical enforcement questions in other guidance documents.[4]

---

[1] *See, e.g.*, EPA Letter from Judith M. Katz, Director Air Protection Division to James Salvaggio, Director of Air Quality, Pa. Dept. of Envtl. Protection *and* EPA Letter from William A. Spratlin, Director, Air, RCRA, and Toxics Division to Peter R. Hamlin, Chief, Air Quality Bureau, Iowa Dept. of Natural Res. (Sept. 18, 1995).

[2] EPA Memorandum, *Withdrawal of Source Determinations for Oil and Gas Industries*, from Gina McCarthy, Assistant Administrator, to Regional Administrators I-X (Sep. 22, 2009) ("[N]o single determination can serve as an adequate justification for how to treat any other source determination for pollutant-emitting activities with different fact-specific circumstances.").

[3] *See* EPA Letter from R. Douglas Neeley, Chief, Air and Radiation Technology Branch to James A. Joy, III, P.E., Chief, Bureau of Air Quality Control, S.C. Dept. of Health and Envtl. Control (Feb. 20, 1998) (noting specifically that both facilities in "situation #2" would be major sources, even when permitted independently).

[4] EPA Letter from Douglas M. Skie, Chief Air Programs Branch, to Jeffery T. Chaffee, Montana Dept. of Health and Envtl. Sciences (Mar. 22, 1990).

Source determinations must be made by the applicable permitting authority, which, in most cases, is the state environmental agency implementing an EPA-approved permitting program. In recognition of this authority, EPA has often pointed out that its guidance documents are only a "recommendation" and that the state or local permitting authority receiving the guidance is responsible for making the final decision. Because NMED is the designated permitting authority under the EPA-approved programs promulgated in the New Mexico State Implementation Plan,[5] NMED has the discretion to make major source determinations in accordance with its own understanding of the facts and circumstances in each case.

1. Common Control

The clearest indication of "common control" is common ownership. EPA has previously relied on the definition of control used by the Securities and Exchange Commission: "[t]he possession, direct or indirect, of the power to direct or cause the direction of management and policies of a person (or organization or association) whether through the ownership of shares, contract, or otherwise."[6] Other EPA guidance indicates that a "common definition" of control should apply, including various dictionary definitions such as "to exercise restraining or directing influence over," "to have power over," "power of authority to guide or manage," and "the regulation of economic activity."[7] Separately-owned facilities can be considered under "common control," but EPA guidance suggests that "a common control determination must focus on who has the power to manage the pollutant-emitting activities of the facilities at issue."[8]

According to a few EPA guidance documents, "contract-for-service" relationships can also indicate "common control" in some cases. However, not all "contract-for-service" relationships require aggregation. Even where one facility provides 100 percent of another's need for a particular input, the decision of the two facilities to locate near one another for convenience does not necessarily lead to "common control." As one example, EPA stated the following in a 1998 guidance document issued to the South Carolina Department of Health and Environmental Control:

> Bowater and GP appear to have a contract-for-service relationship since Bowater supplies one hundred percent of GP's raw materials for power, wastewater treatment, and wood chips. … However, in determining if there is a common control relationship between Bowater and GP, one needs to understand more clearly how these "companion" facilities interact with each other. Although Bowater provides integral services to GP, the GP facility does not appear to be dependent upon the Bowater facility for operation except by convenience, therefore the facilities do not appear to be under common control.[9]

---

5 *See* 40 C.F.R. Part 52 Subpart GG.

6 17 C.F.R. 210.1-02(g); *see* EPA Letter from Cheryl L. Newton, Chief, Permits and Grants Section, to Robert Hodanbosi, Ohio Environmental Protection Agency (July 15, 1997).

7 *See, e.g.*, EPA Letter from William A. Spratlin, Director, Air, RCRA, and Toxics Division to Peter R. Hamlin, Chief, Air Quality Bureau, Iowa Dept. of Natural Res. (Sept. 18, 1995).

8 *See* EPA Letter from Robert B. Miller, Chief, Permits and Grants Section to William Baumann, Chief, Combustion and Forest Products Section, Wis. Dept. of Natural Res. (Aug. 25, 1999) (citing EPA Memorandum, *Major Source Determinations for Military Installations under the Air Toxics, New Source Review, and Title V Operating Permit Programs of the Clean Air Act*, from John S. Seitz, Director, Office of Air Quality Planning and Standards (Aug. 2, 1996)).

9 EPA Letter from R. Douglas Neeley, Chief, Air and Radiation Technology Branch to James A. Joy, III, P.E., Chief, Bureau of Air Quality Control, S.C. Dept. of Health and Envtl. Control (Feb. 20, 1998).

In addition to the above factors, EPA has also considered the following list of questions in determining whether two facilities were under "common control of the same person(s)," which has been repeated in several EPA guidance documents:

1. Do facilities share common workforces, plant managers, security forces, corporate executive officers, or board of executives?

2. Do the facilities share equipment, other property, or pollution control equipment? What does the contract specify with regard to pollution control responsibilities of the contractee? Can the managing entity of one facility make decisions that affect pollution control at the other facility?

3. Do the facilities share common payroll activities, employee benefits, health plans, retirement funds, insurance coverage, or other administrative functions?

4. Do the facilities share intermediates, products, byproducts, or other manufacturing equipment? Can the new source purchase raw materials from and sell products or byproducts to other customers? What are the contractual arrangements for providing goods and services?

5. Who accepts the responsibility for compliance with air quality control requirements? What about for violations of the requirements?

6. What is the dependency of one facility on the other? If one shuts down, what are the limitations on the other to pursue outside business interests?

7. Does one operation support the operation of the other? What are the financial arrangements between the two entities?[10]

These questions demonstrate the wide variety of factors that have been considered in separate source determinations involving a question of "common control."

2. Same Major Industrial Group

As noted above, both the EPA and the New Mexico regulations indicate that facilities should only be aggregated if they belong to the "same major industrial group." To further define this factor, both the federal and New Mexico regulations specifically refer to the 1987 "standard industrial classification manual" (SIC) as a means for distinguishing between separate sources. According to the regulations, only facilities with the same two-digit SIC code should be aggregated together.

EPA's motivation in selecting SIC codes as a determining factor in the source aggregation analysis was made clear in its 1980 revisions to the Title V definition of "major source." As noted in the preamble those revisions, EPA intended to "maximize the predictability of aggregating activities and to minimize the difficulty of administering the definition," using a "widely-known" and "widely-used" classification system.[11] Fearing that a more "abstract factor" would have "embroiled the Agency in numerous, fine-grained analyses," EPA hoped the SIC code criterion would provide "objectivity and

[10] *See, e.g.*, EPA Letter from William A. Spratlin, Director, Air, RCRA, and Toxics Division to Peter R. Hamlin, Chief, Air Quality Bureau, Iowa Dept. of Natural Res. (Sept. 18, 1995).

[11] 45 Fed. Reg. 52676.

relative simplicity," while reducing both the "likelihood of artificially dividing a set of activities" and the "likelihood of disputes over whether a set of activities falls entirely into one category or another."

On the other hand, EPA's 1980 preamble also suggests that the SIC code criterion is not necessarily absolute because "support facilities," *i.e.*, ones that merely "convey, store, or otherwise assist in the production of the principal product," should be considered part of the same industrial group as the primary facility.[12] In later guidance documents, EPA has defined a "support facility" to be one that either provides a significant percentage of the inputs or accepts a significant portion of the outputs of a nearby facility.[13] However, the "support facility" concept is primarily relevant in considering the SIC code criterion, as made clear in EPA's 2001 guidance document for combined heat and power facilities (CHPs):

> The definition of "building, structure, facility, or installation" provides three tests: (1) is the CHP adjacent or contiguous to the host? (2) Is the CHP under common control with the host? – and (3) is the CHP **either (a) part of the same standard industrial classification (SIC) code as the host, or if not, (b) is the CHP a support facility** for the host? If the answer to all three tests were "yes", then we would consider the CHP a single source together with the host. If the answer to any of the three tests were "no", then we would consider the CHP to be a separate source from the host.[14]

As recently as last year, EPA confirmed that the support facility analysis "is distinct from the analysis of whether facilities are under common control."[15] This approach is also confirmed in other guidance documents that recommend against aggregating "support facilities" where they are not under "common control." For example, EPA determined in 1999 that an Oscar Mayer facility should remain separate from six co-located generators, in spite of any "support facility" relationship, because "nothing in its contract with the owner, MGE, indicated that Oscar Mayer will have any power to manage the generators' pollutant-emitting activities or to make any decisions relating to emission control or compliance with environmental regulations."[16]

Although some EPA guidance documents appear to apply the "support facility" concept more broadly, at least one court has rejected the use of a "support facility" entirely. In *Color Communications* the court held:

> In this case the plain language of the statute, as set forth above, clearly requires that if several stationary sources have the same two-digit SIC code, they must be considered to belong to a single major industrial grouping. Accordingly, an industrial grouping is defined by SIC codes. A plain

---

[12] 45 Fed. Reg. 52676.

[13] *See* EPA Letter from Robert B. Miller, Chief, Permits and Grants Section to William Baumann, Chief, Combustion and Forest Products Section, Wis. Dept. of Natural Res (Aug. 25, 1999) (suggesting that a 50% presumption should be used to identify "support facilities."

[14] EPA Memorandum, *Source Determinations for Combined Heat and Power Facilities under the Clean Air Act New Source Review and Title V Programs*, John S. Seitz, Director, Office of Air Quality Planning and Standards, (Oct. 15, 2001) (emphasis added). Although this guidance focuses primarily on CHP, the quote provided above remains a good example of EPA's site determination analysis generally.

[15] *In the Matter of Williams Four Corners, LLC, Sims Mesa CDP Compressor Station*, Permit No. P026R2, 2011 EPA CAA Title V LEXIS 10 (July, 29, 2011).

[16] EPA Letter from Robert B. Miller, Chief, Permits and Grants Section to William Baumann, Chief, Combustion and Forest Products Section, Wis. Dept. of Natural Res. (Aug. 25, 1999).

reading of this statute is that if several stationary sources do not have the same two-digit SIC code, they do not belong to the same industrial grouping. Where a statute is clear and unambiguous, as this one is, a court is not at liberty to depart from its plain language and meaning by reading into it limitations or conditions that the legislature did not express [internal citation omitted]. By relying on the support-facility concept, the Board improperly looked beyond the unambiguous language of the statute to determine whether the two plants belonged to a single industrial grouping. Accordingly, the Board erred in concluding the plants constituted a single "source" for CAAPP purposes.[17]

B. NMED Source Determination Guidance

NMED has issued its own guidance document, although that guidance relies heavily on EPA guidance.[18] Interestingly, the one court case cited in NMED's guidance is *Color Communications,* which, as noted above, rejected the use of the "support facility" concept because the regulations do not define or contain the term.[19] Despite the citation to *Color Communications*, NMED's guidance nevertheless quotes EPA guidance letters that recognize a "support facility" relationship may be relevant in making a source determination. Even so, the longest of NMED's quotes, appearing on both page 4 and page 6 of its guidance, is to the 1999 Oscar Mayer guidance cited above, which contains the following statement, confirming confirms that a "support facility" relationship does not necessarily result in "common control." (although the statement below is not included in the quote found in NMED's guidance):

[E]ven if the facts here establish a support relationship, we are concerned that the Oscar Mayer facility and the six generators at issue may not be under "common control" so as to make them one stationary source.

Even more importantly, none of the letters quoted in NMED's guidance would aggregate separately-owned facilities on the basis of a "support facility" relationship.

C. Description of the San Juan Generating Station and the San Juan Coal Mine

The Plant and the Mine are located on separately-owned properties near Farmington, New Mexico. Although the properties share a common boundary, the emission units located at each facility are distinct from one another and the Plant and the Mine are under completely separate ownership – the Public Service Company of New Mexico, a subsidiary of PNM Resources, Inc., owns[20] and operates the Plant, whereas the Mine is owned by the BHP Billiton's San Juan Coal Company. Neither owner retains any ownership interest in or management control over the other.

---

[17] *Color Communications, Inc. v. Ill. Pollution Control Bd.*, 680 N.E.2d 516 (Ill. App. Ct. 1997) *affirmed without published opinion in* 686 N.E.2d. 1159 (Ill. 1997).

[18] *See* "Single Source Determination Guidance" (available at http://www.nmenv.state.nm.us/aqb/permit/).

[19] *Color Communications, Inc. v. Ill. Pollution Control Bd.*, 680 N.E.2d 516 (Ill. App. Ct. 1997) *affirmed without published opinion in* 686 N.E.2d. 1159 (Ill. 1997).

[20] PNM holds an approximate 46% ownership interest in the plant. The remainder is co-owned by the County of Los Alamos, the City of Farmington, the City of Anaheim, California, M-S-R Public Power Agency, Utah Associated Municipal Power Systems, the Southern California Public Power Authority, Tri-State Generation and Transmission Association, Inc., and Tucson Electric Power.

The Mine produces coal for use at the Plant and does not provide coal to other customers. The Plant, on the other hand, has purchased coal from other mines in the past, including the La Plata mine located over 20 miles to the northeast. The Plant is also currently evaluating whether there are other sources of coal that can be used to fuel the Plant, including the Navajo Mine, from which the Four Corners Power Plant obtains its coal (located to the southwest of the Plant), and other mines to the north. The Plant also pays the Mine to dispose of some of the ash and gypsum it produces, and sells ash meeting certain characteristics to other industries.

Although a conveyor belt carries the coal from the Mine to the Plant's coal pile and is distributed via conveyors owned by the Mine on Plant property, the Plant and the Mine do not share any equipment, and no other equipment from either facility is maintained on the other's property. Access to each facility is separated via separate private roads. The facilities also do not share personnel – both facilities maintain their own separate work forces, separate managerial staff, and separate security forces. The facilities also maintain separate administrative functions, such as payroll, employee benefit plans, insurance policies, etc. For the entire history of the two facilities, the Plant and Mine have also maintained separate licenses and permits, including those related to environmental regulations, and specifically air quality regulations. As such, each facility has always been independently responsible for the separate environmental compliance obligations applicable to each facility.

Simply put, the Mine has no control over the Plant. The Mine cannot control the operating level of the four generating units or require the Plant to startup or shutdown a generating unit. The Mine has no influence over the Plant's maintenance practices, nor can it direct the activities undertaken at the Plant to ensure environmental regulatory compliance.

The Plant's only influence over the Mine arises via equal representation in a two-person "coordination committee" and a four-person "joint committee" for the purposes of coordinating the purchase and delivery of coal. However, the authority granted the Plant's members of those committees is restricted to the powers granted to those committees, which are limited to matters that do not reflect control over pollutant-emitting activities, such as the following:

- approval of price adjustments
- invoicing
- coal quality monitoring
- methods of coal delivery
- approval of changes to mining plans and methods previously established
- establishing general policies and procedures for determining the amount of coal to be purchased

The committees in which the Plant participates do not have control over the daily operations at the Mine or activities to maintain regulatory compliance. The Mine determines the rate at which coal is produced and the manner in which coal is produced. Often more coal is produced at the Mine than is needed at the Plant, in which case the coal is stockpiled on Mine property.

Because it has the potential to emit greater than 100 tons per year of a regulated pollutant, the Plant is already considered a "major stationary source" for permitting purposes. With the advent of EPA's new greenhouse gas permitting rules, the Mine has now become a "major stationary source" as well, albeit solely by virtue of its greenhouse gas emissions. As such, both the Plant and the Mine are already independently and separately subject to the major source Title V Operating Permit program. Therefore, aggregating the two sources will not change the regulatory status of either facility for permitting purposes, although it would allow the facilities to utilize "contemporaneous netting" under the PSD permitting program for any future projects that might otherwise trigger pre-construction permitting requirements.

D. Separate Source Determination

Separate permitting of the two facilities would not only be consistent with past NMED practice, but also with historical EPA practice and guidance, which indicates that mine-mouth power plants need not be aggregated with the mines that serve them.[21] The best example of EPA's application of its source determination policy to a mine-mouth power plant comes from EPA's 1990 Draft NSR Workshop Manual, which specifically confirms that a separately-owned power plant and a coal mine need not be aggregated:

> In this example the proposed project is a new coal-fired electric plant. The plant will have two 600-MW lignite-fired boilers. The proposed location is near a separately-owned surface lignite mine, which will supply the fuel requirements of the power plant, and will therefore, have to increase its mining capacity with new equipment. The lignite coal will be mined and then transported to the power plant to be crushed, screened, stored, pulverized and fed to the boilers. … The first step is to determine what constitutes the source (or sources). A source is defined as all pollutant-emitting activities associated with the same industrial grouping, located on contiguous or adjacent sites, and under common control or ownership. Industrial groupings are generally defined by two-digit SIC codes. The power plant is classified as SIC major group 49; the nearby mine is SIC major group 12. They are neither under the same SIC major group number nor have the same owners, so they constitute separate sources. [22]

Even though the Mine and the Plant are located on contiguous properties, the facilities are not "under common control of the same person(s)" and do not fall within the same industrial grouping or SIC code. Accordingly, they should not be aggregated for air quality permitting purposes.

1. The Plant and the Mine Are Not "Under Common Control of the Same Person(s)."

As indicated above, the Plant and the Mine are not under common ownership.[23] Therefore, the only way the two facilities could be deemed "under common control of the same person(s)" would be indirectly through the contractual relationship between PNM and BHP. However, nothing in the contracts between the Plant and the Mine authorize either owner to control the pollutant emitting activities of the other – as noted above, the Plant cannot control the mining, ash disposal, or reclamation activities at the Mine, and the Mine cannot control operations, maintenance, or capital expenditure decisions at the Plant. As such, the relationship between the Plant and the Mine is similar to the example from the portion of the 1990 Draft NSR Workshop Manual quoted above.

---

[21] *Compare* EPA Memorandum, *PSD Evaluation of Secondary Emissions for Houston Lighting and Power*, from Edward F. Tuerk, Acting Assistant Administrator, to Allyn M. Davis, Director, Air and Hazardous Materials Division (Mar. 17, 1981) (addressing whether separately permitting coal mine emissions should be considered as secondary emissions in permitting a mine-mouth power plant) *with* EPA Memorandum, PSD Applicability Determination, from Director, Division of Stationary Source Enforcement, to Allyn Davis, Director, Air and Hazardous Materials Division (Apr. 24, 1980) (determining that a mine-mouth power plant and a mine under common ownership should be aggregated prior to the adoption of the SIC code criterion into the federal Title V regulations). *Cf.* EPA Letter from Cheryl L. Newton, Acting Director, Air and Radiation Division, to Janet McCabe, Ind. Dept. of Envtl. Mgmt. (Mar. 6, 2003) (assuming that coal mine deemed to be a support facility of a power plant must be aggregated together without considering all three source determination criteria).

[22] EPA Draft NSR Workshop Manual, Gary McCutchen, p. A-28 (1990).

[23] Although PNM held an ownership interest in the Mine up until the late 1970's, that relationship was severed long ago. In any event, the fact that the facilities have been permitted separately since the 1970's suggests that the previous ownership relationship did not require aggregation of the sources.

The Plant and the Mine are also similar the 2002 EPA guidance document in which EPA recommended that the state of Virginia allow a landfill and a co-located power generator to remain separate sources, even though the power generator agreed to purchase all of the landfill's gas and pay for it even if the power generator did not use all the gas. In that 2002 determination, EPA reasoned that, despite the "contract-for-service" relationship between the two facilities, the power generator was still in control of the valve that allowed landfill gas to flow to its engines. As such, the power generating facility maintained sufficient control over its own emitting operations to remain a separate source for permitting purposes.[24] Thus, even if the contract between Plant and the Mine is deemed to establish a "contract-for-service" relationship, the separate operational control each facility has over its emitting activities confirms the need for separate air quality permits.

Another "common sense" reason to continue separate permitting of the Plant and the Mine is that a single, combined permit could complicate any future compliance activities or efforts to resolve future enforcement actions. For example, if PNM's Plant exceeded a stack test, BHP would have no right or authority to take any action to address those excess emissions at the Plant. Likewise, PNM would have no right or authority to address any excess emissions concerns that may arise at the Mine. It would make little practical sense to aggregate the sources, given the lack of control each has over the other's compliance obligations. In the past, EPA has considered such concerns in deciding to recommend separate permitting for separate sources, and NMED's own guidance recognizes the practical enforcement difficulties that would likely arise if the Plant and the Mine were aggregated together.[25]

2. The Two Facilities Do Not Belong to the Same Industrial Category.

Based on the language of the applicable federal and state regulations, and the reasoning of the *Color Communications* decision, the Plant and the Mine should not be aggregated because they do not belong to the same industrial group and have different two-digit SIC codes. Such a determination would be consistent with EPA's stated purpose for adopting the SIC code criteria in the 1980 definition of "major source" – *i.e.*, predictability and objectivity. EPA's 1980 Prevention of Significant Deterioration Workshop Manual confirms this approach. Not only was the 1980 manual written contemporaneously with EPA's source determination regulations, and is therefore the best indication of the intent underlying those regulations, it contains a specific example to address the mine-mouth power plant scenario, as quoted below:

> [T]he proposed project will be a new coal-fired electric plant. Construction is scheduled to begin in 1981. The plant will have two 600-MW lignite-fired boilers. Because a surface lignite mine in dedicated service to the power plant will be located on adjacent properties, the power plant is classified as a minemouth power-generating station. The power plant will have onsite coal and limestone storage and handling facilities. The mine and the power plant will be under common ownership. … When examining this proposed construction for PSD applicability, the source or sources must first be determined. The PSD guidelines define a source as all pollutant-emitting activities associated with the same industrial grouping, located on contiguous or adjacent sites, and under common control or ownership. Industrial groupings are generally defined by two-digit SIC

[24] EPA Letter from Judith M. Katz, Director, Air Protection Division, to Gary E. Graham, Va. Dept. of Envtl. Quality (May 1, 2002).

[25] "Single Source Determination Guidance" (available at http://www.nmenv.state.nm.us/aqb/permit/) (emphasizing with bold lettering the following question raised in an EPA guidance document: "**If the Department's decision is to issue one permit, how will the liability issue be handled …?**").

codes. In this case, the power plant, which is classified as SIC major group 49, and the adjacent mine, which is SIC major group 12, constitute separate sources.

Thus, based on the guidance above, prepared contemporaneously with the regulations that continue to apply, dedicated coal mines need not be aggregated with the power plants they serve. However, even if the Mine is deemed to have the same SIC code as a "support facility" for the Plant, the facilities remain under separate control, like the coal mine and the power plant considered in the example provided in the 1990 version of the NSR Workshop Manual. Since separate control can be an independent basis for allowing two facilities to be permitted separately, the Plant and the Mine should not be aggregated.[26]

E. Conclusion

As demonstrated above, the Plant and the Mine are separate sources because they are not under "common control of the same person(s)" and do not belong to the same industrial group. In addition, the fact that both sources are already "major stationary sources" confirms that aggregation of the facilities will not change the status of either facility under the Clean Air Act Title V permitting program. Aggregation is thus inappropriate because it would unnecessarily complicate compliance obligations and any future enforcement actions without providing any benefit to the environment.

[26] *See, e.g.*, Letter from Reginald D. Olsen, Utah Division of Air Quality, to Jim M. Wolfe, IMC Global, Inc. (Feb. 14, 2001) (indicating that a support facility and its host facility could be permitted separately despite prior EPA guidance indicating aggregation would be appropriate because the facilities were no longer co-owned).

Section 12

Section 12.A
PSD Applicability Determination for All Sources

(Submitting under 20.2.72, 20.2.74 NMAC)

A PSD applicability determination for all sources. For sources applying for a significant permit revision, apply the applicable requirements of 20.2.74.AG and 20.2.74.200 NMAC and to determine whether this facility is a major or minor PSD source, and whether this modification is a major or a minor PSD modification. It may be helpful to refer to the procedures for Determining the Net Emissions Change at a Source as specified by Table A-5 (Page A.45) of the EPA New Source Review Workshop Manual to determine if the revision is subject to PSD review.

A. This facility is:

- ☐ **a minor PSD source before and after this modification (if so, delete C and D below).**
- ☐ **a major PSD source before this modification. This modification will make this a PSD minor source.**
- X **an existing PSD Major Source that has never had a major modification requiring a BACT analysis.**
- ☐ **an existing PSD Major Source that has had a major modification requiring a BACT analysis**
- ☐ **a new PSD Major Source after this modification.**

B. **This facility is one of the listed 20.2.74.501 Table I – PSD Source Categories. The "project" emissions for this project are not significant. The only emissions that could increase as a result of this project are sulfuric acid mist (H_2SO_4) and particulate matter, and the calculations in ATTACHMENT ___ confirm that the increase will not exceed the significance levels for those pollutants of 7 tpy and 25 tpy, respectively. The "project" emissions are listed below; see ATTACHMENT ___ for more information. This project will not result in "de-bottlenecking", or other increases in emissions. The project emissions (before netting) for this project are as follows [see Table 2 in 20.2.74.502 NMAC for a complete list of significance levels]:**

See discussion below

C. **Netting is not required (project is not significant).**

D. **BACT** is **not required.**

E. If this is an existing PSD major source, or any facility with emissions greater than 250 TPY (or 100 TPY for 20.2.74.501 Table 1 – PSD Source Categories), determine whether any permit modifications are related, or could be considered a single project with this action, and provide an explanation for your determination whether a PSD modification is triggered.

No other permit modifications are related to this permit application.

Although the installation of the SCR and DSI systems at SJGS constitute "physical changes" and can affect the emission rates of certain pollutants, the emission calculations below confirm that the projects will not result in a significant emissions increase and thus do not trigger PSD pre-construction permitting requirements.

I. Sulfuric Acid

SCR systems can generate sulfuric acid because the same chemical reaction that converts nitrogen oxides (NO_x) into nitrogen and water also oxidizes sulfur dioxide (SO_2) into sulfur trioxide (SO_3), which naturally reacts with water vapor to form sulfuric acid (H_2SO_4). However, the calculations below confirm that the installation and operation of SCR systems at SJGS will not result in a significant emissions increase of sulfuric acid.

Unit	Emission Rate & Data Source	Baseline Heat Input and 24-Month Baseline Period[1]	Baseline Actual Emissions
Unit 1	0.0000463 lb/mmBtu EPA-assumed emission factor for sulfuric acid released from boiler combustion	26,821,092 mmBtu 12/14/2008 19:00 – 12/14/2010 18:00	0.62 tpy
Unit 2		23,467,448 mmBtu 6/11/2009 10:00 – 6/11/2011 9:00	0.54 tpy
Unit 3		38,033,388 mmBtu 3/26/2008 0:00 – 3/26/2010 23:00	0.88 tpy
Unit 4		41,890,730 mmBtu 1/29/2008 23:00 – 1/29/2010 22:00	0.97 tpy

Unit	Emission Rate & Data Source	Maximum Potential Heat Input[2]	Potential to Emit
Unit 1	0.00026 lb/mmBtu PTE based on FIP emission limit for sulfuric acid	32,473,320 mmBtu	4.22 tpy
Unit 2		32,473,320 mmBtu	4.22 tpy
Unit 3		50,440,080 mmBtu	6.56 tpy
Unit 4		50,440,080 mmBtu	6.56 tpy

Unit	Potential Emissions Increase
Unit 1	3.60 tpy
Unit 2	3.68 tpy
Unit 3	5.68 tpy
Unit 4	5.59 tpy

[1] Because the beginning of actual construction on the SCR projects is expected to occur in October 2012, the look-back period for baseline actual emissions is November 2007 through September 2012. The calculations above are based on continuous monitoring data (available through December 2011).

[2] Based on the maximum hourly heat input rating of 3,707 mmBtu/hr for Units 1 & 2 and 5,758 mmBtu/hr for Units 3 & 4, each multiplied by 8,760 hours per year.

The conservative "actual-to-potential" emissions calculations provided above confirm that, based on the emission factors assumed in EPA's Federal Implementation Plan for the SJGS, the installation of each SCR will not increase sulfuric acid emissions by more than the applicable PSD significance level of 7 tpy. As noted elsewhere in this permit application, PNM questions the emission factors assumed in EPA's FIP analysis and the ability of existing test methods to accurately measure sulfuric acid at the FIP emission limit. PNM also questions the need for a sulfuric acid limit at all, since emissions can be minimized via the design of the SCR (in much the same way as ammonia emissions). However, since the FIP will require SJGS to meet a sulfuric acid emission limit following the installation of the SCRs that results in a

PTE for each unit that is less than the 7 tpy sulfuric acid PSD significance level, a significant emissions increase cannot occur under the FIP, regardless of baseline actual emissions. As a result, the SCR projects do not trigger PSD permitting requirements for sulfuric acid.

Each unit is analyzed separately because the individual SCR projects at each unit need not be aggregated together under EPA's "aggregation policy" for PSD. That policy indicates that projects that are "substantially related," either "technically or economically," must be analyzed together as one project in determining PSD applicability for any projected emissions increases. EPA sought to "clarify" its existing aggregation policy in 2006 by proposing to codify regulatory language providing that "[p]rojects occurring at the same major stationary source that are dependent on each other to be *economically or technically* viable are considered a single project." 71 Fed. Reg. 54,235, 54,251 (Sept. 14, 2006). In 2009, however, EPA finalized the rule by abandoning the proposed regulatory language in favor of general statements indicating that separate projects should only be "aggregated" if they are "substantially related." In the preamble to that final rule, EPA defined "substantially related" as follows:

> To be "substantially related," there should be an apparent interconnection--either technically or economically--between the physical and/or operational changes, or a complementary relationship whereby a change at a plant may exist and operate independently, however its benefit is significantly reduced without the other activity.

74 Fed. Reg. 2376, 2378 (Jan. 15, 2009). Thus, although EPA later stayed the final 2009 rule, its "clarifications" in the preamble to the 2006 proposal and the preamble to its final 2009 rule confirm that EPA has consistently defined its PSD aggregation policy in the past through reference to the technical and economic relatedness of otherwise separate projects.

The SCR projects at each SJGS unit will not be "substantially related" because there will be no technical or economic interconnection between them, and the benefit provided by one SCR will not be affected by the presence or the absence of another SCR. Each SCR will be entirely capable of operating independently, and the operation of each SCR will be tied to the operation of only one of the generating units at the site, each of which will operate independently as well. The SCR projects at each unit are also economically independent. To the extent economics are relevant for pollution control projects necessary to comply with applicable regulations, the decision to install an SCR at each SJGS generating unit would be tied to the economic viability of each unit, which is analyzed independently by PNM. The fact that one generating unit remains economically viable in spite of the costs associated with installing an SCR does not necessarily mean that another unit at the site will remain economically viable, and the installation of one SCR will not make the decision to install an SCR at another generating unit more or less economically viable. Therefore, since the individual SCR projects at each unit are not substantially related on either a technical or economic basis, they need not be aggregated together under EPA's "aggregation policy."

II. Carbon Dioxide

A. Dry Sorbent Injection

The DSI systems planned for SJGS will be capable of utilizing either hydrated lime ($Ca(OH)_2$), Trona (sodium sesquicarbonate) or sodium bicarbonate ($NaHCO_3$ or SBC). Two of those sorbents, Trona and SBC, can result in the formation of additional carbon dioxide (CO_2) through the same chemical reaction necessary to reduce other regulated pollutants. However, the calculations below confirm that the use of either of these two sorbents at SJGS will not result in a significant emissions increase.

Unit	Maximum Emission Rate & Data Source[1]	Maximum Potential SBC Injection Rate[2]	Potential to Emit3
Unit 1	Mass Ratio of SBC to CO_2: 0.52	240.68 lb/hr	552.3 tpy
Unit 2		240.68 lb/hr	552.3 tpy
Unit 3		373.84 lb/hr	857.8 tpy
Unit 4		373.84 lb/hr	857.8 tpy

1 The calculations are based on SBC because it has the highest CO_2 generation rate (based on CO2/sorbent mass ratio) of the sorbents currently under consideration for use in the SJGS DSI systems.

2 The maximum injection rate is based on an injection location upstream of the air preheater with a conservative estimate of inlet SO_2 concentrations and a target outlet concentration of approximately 2 ppm.

3 The CO_2 emissions estimates above assume injection location upstream of the air preheater, and PNM has conservatively assumed that all of the sorbent will be completely calcined with no unreacted sorbent.

The conservative "actual-to-potential" emissions calculations provided above confirm that the installation of each DSI system will not increase CO_2 emissions by more than the applicable PSD greenhouse gas permitting threshold of 75,000 tpy of CO_2 equivalent (CO_2e). As a result, the projects do not trigger permitting requirements for greenhouse gases.

B. Selective Non-Catalytic Reduction (SNCR) System

If the judicial review of the EPA's regional haze FIP is overturned and/or EPA approves the New Mexico regional haze SIP in replacement of the FIP, PNM will install a Selective Non-Catalytic Reduction (SNCR) system on each unit in lieu of the SCR and DSI systems. Although SNCR systems involve the injection of urea instead of the sorbents listed above, urea also has the potential to produce additional CO_2 emissions through the chemical reactions between the urea and nitrogen oxide (NO). However, based on a conservative "actual-to-potential" emission calculation, assuming a maximum potential use of 77,581.9 lbs of urea per day, the total annual CO_2 emissions increase attributable to an SNCR would be 2,628 tpy PTE for Unit 1, 2,628 tpy PTE for Unit 2, 3,942 tpy PTE for Unit 3 and 3,942 tpy PTE for Unit 4. Because this CO_2 emissions increase would be well below the applicable PSD greenhouse gas permitting threshold of 75,000 tpy of CO_2 equivalent (CO_2e), the SNCR alternative included in this permit application would not trigger permitting requirements for greenhouse gases.

III. Particulate Matter

The injection of sorbents into the flue gas stream can have the potential to increase particulate matter (PM) emissions, since the sorbents themselves constitute PM if emitted from the stack. However, the existing SJGS baghouses are "constant output devices" – *i.e.*, capable of achieving a constant PM emission rate regardless of inlet PM concentrations, so long as the inlet concentrations are within the design capacity of the baghouses. The injection of sorbents via new DSI systems at SJGS are not expected to increase inlet concentrations beyond the design inlet capacity of the baghouses. Therefore, despite the minimal increase in inlet PM emissions that could result from the injection of sorbents, stack PM emissions are not expected to change as a result of the installation and operation of the DSI systems at SJGS. Operation of the DSI and SCR or SNCR will result in a small increase in PM emissions due to increased truck traffic from sorbent deliveries. However, the increased PM emissions from additional truck traffic are well below the PSD significance threshold. As a result, the projects do not trigger PSD permitting requirements for PM.

Section 13

Discussion Demonstrating Compliance With Each Applicable State & Federal Regulation

Provide a discussion demonstrating compliance with applicable state & federal regulation. If there is a state or federal regulation (other than those listed here) for your facility's source category that does not apply to your facility, but seems on the surface that it should apply, add the regulation to the appropriate table below and provide the analysis. Examples of regulatory requirements that may or may not apply to your facility include 40 CFR 60 Subpart OOO (crushers), 40 CFR 63 Subpart HHH (HAPs), or 20.2.74 NMAC (PSD major sources). We don't want a discussion of every non-applicable regulation, but if there is questionable applicability, explain why it does not apply. All input cells should be filled in, even if the response is 'No' or 'N/A'.

In the "Justification" column, identify the criteria that are critical to the applicability determination, numbering each. For each unit listed in the "Applies to Unit No(s)" column, after each listed unit, include the number(s) of the criteria that made the regulation applicable. For example, TK-1 & TK-2 would be listed as: TK-1 (1, 3, 4), TK-2 (1, 2, 4). Doing so will provide the applicability criteria for each unit, while also minimizing the length of these tables.

As this table will become part of the SOB, please do not change the any formatting in the table, especially the width of the table.

If this application includes any proposed exemptions from otherwise applicable requirements, provide a narrative explanation of these proposed exemptions. These exemptions are from specific applicable requirements, which are spelled out in the requirements themselves, not exemptions from 20.2.70 NMAC or 20.2.72 NMAC.

Table for Applicable STATE REGULATIONS:

STATE REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION: Identify the applicability criteria, numbering each (i.e. 1. Post 7/23/84, 2. 75 m^3, 3. VOL)
20.2.3 NMAC	Ambient Air Quality Standards NMAAQS	X		X		20.2.3 NMAC is a SIP approved regulation that limits the maximum allowable concentration of Total Suspended Particulates, Sulfur Compounds, Carbon Monoxide and Nitrogen Dioxide.
20.2.7 NMAC	Excess Emissions	X		X		All Title V major sources are subject to Air Quality Control Regulations, as defined in 20.2.7 NMAC, and are thus subject to the requirements of this regulation. Also listed as applicable in NSR Permit NM063M6R1.
20.2.14 NMAC	Particulate Emissions from Coal Burning Equipment		E301, E302, E303, E304	X		Limits PM emissions from main boiler stacks. 0.05 lb TSP/mmBtu (3-hr avg) OR 0.02 lb PM2/mmBtu(E301,E303,E304), 0.04 lb PM2/mmBtu (E302).
20.2.31 NMAC	Coal Burning Equipment - Sulfur Dioxide		E301, E302, E303, E304	X		Limits SO2 emissions from main boiler stacks. 13,000 lbs/hr (combined, 3-hr avg); 0.55 lb mmBtu (30-day avg); 1.2 lbs/mmBtu (3-hr avg. E301, E303, E304); 28% (30-day avg, E302).
20.2.32 NMAC	Coal Burning Equipment: NO_2		E301, E302, E303, E304	X		Limits Nox emissions from main boiler stacks. 0.45 lb/mmBtu (3-hr avg E301, E303, E304); 0.7 lb/mmBtu (3-hr avg, E302).
20.2.61 NMAC	Smoke and Visible Emissions		Emergency Generators E602, E603, E604,	X		The SJGS are exempt/insignificant sources, but still must meet opacity limits per 20.2.61 NMAC.

STATE REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION: Identify the applicability criteria, numbering each (i.e. 1. Post 7/23/84, 2. 75 m^3, 3. VOL)
			E605, E606			
20.2.70 NMAC	Operating Permits	X		X		Source is major for NOx, CO, VOCs, SO_2, and Total HAPs.
20.2.71 NMAC	Operating Permit Fees	X		X		Yes, this facility is subject to 20.2.70 NMAC and is in turn subject to 20.2.71 NMAC.
20.2.72 NMAC	Construction Permits	X		X		This facility is subject to 20.2.72 NMAC.
20.2.73 NMAC	NOI & Emissions Inventory Requirements	X		X		All Title V major sources meet the applicability requirements of 20.2.73.300 NMAC.
20.2.75 NMAC	Construction Permit Fees	X		X		This facility is subject to 20.2.72 NMAC and is in turn subject to 20.2.75 NMAC.
20.2.77 NMAC	New Source Performance		NSPS Subpart D for E301, E303, E304; NSPS OOO for certain limestone handling sources	X		This is a stationary source which is subject to the requirements of 40 CFR Part 60, as amended through September 1, 2002.
20.2.84 NMAC	Acid Rain Permits		E301, E302, E303, E304	X		Requires SJGS to have an acid rain permit for the coal boiler units.
20.2.85 NMAC	Mercury Emissions Standards and Compliance Schedules for Electrical Generating Units		E301, E302, E303, E304			Requires SJGS coal boiler units to comply with mercury emission provisions.
20.2.75 NMAC	Construction Permit Fees					This facility is subject to 20.2.72 NMAC and is in turn subject to 20.2.75 NMAC. N/A if subject to 20.2.71 NMAC.
20.2.77 NMAC	New Source Performance					This is a stationary source which is subject to the requirements of 40 CFR Part 60, as amended through January 31, 2009.

STATE REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION: Identify the applicability criteria, numbering each (i.e. 1. Post 7/23/84, 2. 75 m^3, 3. VOL)
20.2.78 NMAC	Emission Standards for HAPS					This facility emits hazardous air pollutants which are subject to the requirements of 40 CFR Part 61, as amended through January 31, 2009.
20.2.79 NMAC	Permits – Nonattainment Areas					This facility is applicable according to 2.79.109 NMAC: **(1)** The major stationary source or major modification will be located within a nonattainment area so designated pursuant to Section 107 of the Federal Act and will emit a regulated pollutant for which it is major and which the area is designated nonattainment for; or **(2)** The major stationary source or major modification will be located within an area designated attainment or unclassifiable pursuant to Section 107 of the Federal Act and will emit a regulated pollutant for which it is major and the ambient impact of such pollutant would exceed any of the significance levels in 20.2.79.119.A NMAC at any location that does not meet any national ambient air quality standard for the same pollutant. (See 20.2.79.109.D NMAC)
20.2.80 NMAC	Stack Heights					Usually not applicable for TV If applies: Cited as applicable in NSR Permit XXX.
20.2.82 NMAC	MACT Standards for source categories of HAPS					This regulation applies to all sources emitting hazardous air pollutants, which are subject to the requirements of 40 CFR Part 63, as amended through January 31, 2009.

Table for Applicable FEDERAL REGULATIONS :

FEDERAL REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION:
40 CFR 50	NAAQS	X		X		Defined as applicable at 20.2.70.7.E.11, Any national ambient air quality standard
NSPS 40 CFR 60, Subpart A	General Provisions		NSPS Subpart D for E301, E303, E304; NSPS OOO for certain limestone handling sources	X		Applies if any other NSPS subpart applies.
NSPS 40 CFR60Subpart D	**Electric Utility Steam Generating Units**		E301, E303, E304	X		Establishes NOx , SO2, PM (Method 5) and opacity limits of boiler units 1,3 and 4. NOx limit is 0.7 lb/mmBtu (3-hr avg); SO2 limit is 1.2 lb/mmBtu (3-hr avg) and TSP 0.1 lb/mmBtu (3-hr avg).
40 CFR 60, Subpart OOO	**Non-metallic Minerals**		E803, E804, S805	X		NSPS standards for non-metallic minerals applies to certain portions of the limestone handling system.
NESHAPS 40 CFR 64	**Compliance Assurance Monitoring**		E301, E302, E303, E304	X		CAM applies to boiler units because they are each major emission sources (>100 tpy) and employ control equipment to insure compliance with emission limits.
NESHAPS 40 CFR 68	**Chemical Accident Prevention**	X		X	NESHAPS 40 CFR 68	SJGS is potentially subject to chemical accident prevention assessment and planning.
Title IV – Acid Rain 40 CFR 72, Subparts B,D and I	**Acid Rain**		E301, E302, E303, E304	X	Title IV – Acid Rain 40 CFR 72, Subparts B,D and I	SJGS coal boiler units are subject acid rain permitting provisions and have an acid rain permit.
Title IV – Acid Rain 40 CFR 73	**Sulfur Dioxide** Allowance Emissions		E301, E302, E303, E304	X	Title IV – Acid Rain 40	SJGS coal boiler units must hold sufficient annual SO2 allowances.

FEDERAL REGU-LATIONS CITATION	Title	Applies to **Entire Facility**	Applies to **Unit No(s).**	**Federally Enforce-able**	**Does Not Apply**	**JUSTIFICATION:**
					CFR 73	
Title IV – Acid Rain 40 CFR 76	**Acid Rain** Nitrogen Oxides **Emission Reduction Program**		E301, E302, E303, E304	X	Title IV – Acid Rain 40 CFR 76	SJGS has filed a NOx averaging plan with EPA and submits required reports.
40CFR77 Excess Emissions	Excess emissions reporting		E301, E302, E303, E304	X	40CFR 77 Excess Emissions	
Title VI – 40 CFR 82	Protection of **Stratospheric Ozone**	X		X	Title VI – 40 CFR 82	SJGS is subject to this part for servicing motor vehicles.

Section 14

Operational Plan to Mitigate Emissions

(submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

☐ **Title V Sources** (20.2.70 NMAC)**:** By checking this box and certifying this application the permittee certifies that it has developed an **Operational Plan to Mitigate Emissions During Startups, Shutdowns, and Emergencies** defining the measures to be taken to mitigate source emissions during startups, shutdowns, and emergencies as required by 20.2.70.300.D.5(f) and (g) NMAC. This plan shall be kept on site to be made available to the Department upon request. This plan should not be submitted with this application.

X **NSR** (20.2.72 NMAC)**, PSD** (20.2.74 NMAC) **& Nonattainment** (20.2.79 NMAC) **Sources:** By checking this box and certifying this application the permittee certifies that it has developed an **Operational Plan to Mitigate Source Emissions During Malfunction, Startup, or Shutdown** defining the measures to be taken to mitigate source emissions during malfunction, startup, or shutdown as required by 20.2.72.203.A.5 NMAC. This plan shall be kept on site to be made available to the Department upon request. This plan should not be submitted with this application.

☐ **Title V** (20.2.70 NMAC)**, NSR** (20.2.72 NMAC)**, PSD** (20.2.74 NMAC) **& Nonattainment** (20.2.79 NMAC) **Sources:** By checking this box and certifying this application the permittee certifies that it has established and implemented a Plan to Minimize Emissions During Routine or Predictable Startup, Shutdown, and Scheduled Maintenance through work practice standards and good air pollution control practices as required by 20.2.7.14.A and B NMAC. This plan shall be kept on site or at the nearest field office to be made available to the Department upon request. This plan should not be submitted with this application.

Section 15

Alternative Operating Scenarios

(submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

Alternative Operating Scenarios: Provide all information required by the department to define alternative operating scenarios. This includes process, material and product changes; facility emissions information; air pollution control equipment requirements; any applicable requirements; monitoring, recordkeeping, and reporting requirements; and compliance certification requirements. Please ensure applicable Tables in this application are clearly marked to show alternative operating scenario.

Two different methods for NOx control are presented in this application. They are identified as Scenario A (SCR) which would be install ed meet the requirements of the FIP and Scenario B (SNCR)which would be installed to meet the requirements of the SIP. Information on both Scenarios has been included in the permit application. Where there are differences between each scenario, the specific information is identify as applying to either Scenario A or Scenario B.

Section 16

Air Dispersion Modeling

NSR (20.2.72 NMAC) and PSD (20.2.74 NMAC) Modeling: Provide an air quality **dispersion modeling** demonstration (if applicable) as outlined in the Air Quality Bureau's Dispersion Modeling Guidelines. If air dispersion modeling has been waived for this permit application, attach the AQB Modeling Section modeling waiver documentation.

SSM Modeling: Applicants must conduct dispersion modeling for the total short term emissions using realistic worst case scenarios following guidance from the Air Quality Bureau's dispersion modeling section. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.nmenv.state.nm.us/aqb/permit/app_form.html) for more detailed instructions on SSM emissions modeling requirements.

Title V (20.2.70 NMAC) Modeling: Title V applications must specify the NSR Permit number for which air quality dispersion modeling was last submitted. Additionally, Title V facilities reporting new SSM emissions require modeling or a modeling waiver to demonstrate compliance with standards.

There are no increases in overall facility emissions and no significant changes to the distribution or dispersion parameters. Therefore modeling is not being submitted. A modeling waiver request has been submitted to the AQB modeling section.

Section 17

Compliance Test History

(submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

To show compliance with existing NSR permits conditions, you must submit a compliance test history. The table below provides an example.

To save paper and to standardize the application format, delete this sentence and the samples in the Compliance Test History Table, and begin your submittal for this attachment on this page.

Compliance Test History Table

Unit No.	Test Description	Test Date
1	EPA Method 5i for Particulate Matter , Method 10 for CO	10/12-13/2011
2	EPA Method 5i for Particulate Matter , Method 10 for CO	11/08/2011
3	EPA Method 5i for Particulate Matter , Method 10 for CO	11/09/2011
4	EPA Method 5i for Particulate Matter , Method 10 for CO	10/14/2011

Section 18

Addendum for Streamline Applications

Do not print this section unless this is a streamline application.

Streamline Applications do not require a complete application. Submit Sections 1-A, 1-B, 1-D, 1-F, 1-G, 2-A, 2-C thru L, Sections 3 thru 8, Section 13, Section 18, Section 22, and Section 23 (Certification). Other sections may be required at the discretion of the Department. 20.2.72.202 NMAC Exemptions do not apply to Streamline sources. 20.2.72.219 NMAC revisions and modifications do not apply to Streamline sources, thus 20.2.72.219 type actions require a complete new application submittal. Please do not print sections of a streamline application that are not required.

18-A: Streamline Category	
1	**Indicate under which part of 20.2.72.301.D this facility is applying. Refer to the forth column of Table 18-D below, to assist in this determination:** ☐ 20.2.72.301.D(1) NMAC ☐ 20.2.72.301.D(2) NMAC ☐ 20.2.72.301.D(3) NMAC

18-B: Streamline Applicability Criteria		Answer (yes/no)
1	Does the source category for this facility meet one of those listed in the following table? (20.2.72.301.A NMAC) **20.2.72.501 Table 2 – Permit Streamlining Source Class Categories** 1. Reciprocating internal combustion engines including portable or temporary engines 2. Turbines	☐ Yes ☐ No
2	If this facility is a compressor station, does it meet the definition of a "Compressor station" below? (20.2.72.301.D NMAC) **"Compressor station"** means a facility whose primary function is the extraction of crude oil, natural gas, or water from the earth with compressors, or movement of any fluid, including crude oil or natural gas, or products refined from these substances through pipelines or the injection of natural gas or CO2 back into the earth using compressors. A compressor station may include engines to generate power in conjunction with the other functions of extraction, injection or transmission and may contain emergency flares. A compressor station may have auxiliary equipment which emits <u>small quantities</u> of regulated air contaminants, including but not limited to, separators, de-hydration units, heaters, treaters and storage tanks, provided the equipment is located within the same property boundaries as the compressor engine (underline added). (20.2.72.301.A NMAC)	☐ Yes ☐ No
3	Will the source operate in compliance with all applicable state and federal regulations, including federal new source performance standards incorporated by 20.2.77 NMAC and permit conditions? (20.2.72.305.B NMAC)	☐Yes ☐No
4	Will the fuel combusted at this facility be produced natural gas, sweet natural gas, liquid petroleum gas, or fuel gas containing 0.1 grain of total sulfur or less per dry standard cubic foot; or refinery grade diesel or No. 2 fuel oil that is not a blend containing waste oils or solvents and contains less than 0.3% by weight sulfur? (20.2.72.306 NMAC)	☐Yes ☐No

5	Will all spark ignited gas-fired or any compression ignited dual fuel-fired engine which operates with a non-selective catalytic converter be equipped and operated with an automatic air-fuel ratio (AFR) controller which maintains AFR in the range required to minimize NOx emissions, as recommended by the manufacturer? (20.2.72.306 NMAC)	☐Yes ☐No
6	Has payment of all fees that are specified in 20.2.75 NMAC (Construction Permit Fees), as payable at the time the application is submitted, been included with the application package? (20.2.72.302.15 NMAC)	☐Yes ☐No
7	Is the answer to each of the above questions, #1 through #6, '**Yes**'? If the answer to **this** question is "**No**", this facility does **not** qualify for a streamline permit.	☐Yes ☐No
8	Will the facility, either before or after construction or modification, have a total potential to emit of any regulated air contaminant[2] greater than 200 tons per year (tpy) of any one regulated air pollutant (CO, NOx, SO2, or VOC)? (20.2.72.301.B.2 NMAC); **"Potential to emit"** or **"potential emissions"** means the maximum capacity of a stationary source to emit a regulated air contaminant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a regulated air contaminant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitations or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.	☐ Yes ☐ No
9	Is the facility a "major stationary source" as defined in 20 NMAC 2.74? (20.2.72.301.B.1 NMAC)	☐ Yes ☐ No
10	Is this source subject 20.2.78 NMAC, other than 40CFR61 Subpart M National Emission Standard for Asbestos? (20.2.72.301.B.3 NMAC)	☐ Yes ☐ No
11	Is this a source of potential air toxic emissions (20 NMAC 2.72. 400-499)? (20.2.72.301.B.3 NMAC)	☐ Yes ☐ No
12	Will the reciprocating internal combustion (IC) engines and/or turbines be located at a petroleum refinery, chemical manufacturing plant, bulk gasoline terminal, natural gas processing plant, or at any facility containing sources in addition to IC engines and/or turbines for which an air quality permit is required through state or federal air quality regulations in the absence of the (IC) engines and/or turbines? (20.2.72.301.B.4 NMAC)	☐ Yes ☐ No
13	Will the proposed facility be located within any of the 20.2.72.301.B.5 exclusion areas specified in the Air Dispersion Modeling Guidelines[1], Table: Areas Where Streamline Permits Are Prohibited ? (20.2.72.301.B.5 NMAC) http://www.nmenv.state.nm.us/aqb/modeling	☐ Yes ☐ No
14	Will the proposed facility's impact area intersect any of the areas specified in the Air Dispersion Modeling Guidelines[1], Table: Areas Where Streamline Permits Are Prohibited ? (20.2.72.301.B.5 NMAC) http://www.nmenv.state.nm.us/aqb/modeling	☐Yes ☐No ☐N/A
15	Is the answer to each of the above questions, #8 through #14, '**No**'? If the answer to **this** question is "**No**", this facility does **not** qualify for a streamline permit.	☐Yes ☐No

[1] The Air Dispersion Modeling Guidelines contain a section on streamline permitting. The table mentioned above can be found within those guidelines at http://www.nmenv.state.nm.us/aqb/modeling

[2] The potential to emit for nitrogen dioxide shall be based on total oxides of nitrogen

18-C: Streamline Location Restrictions		Answer (yes/no)	Identify: Name and Distance (km)
1	Will the distance from the nearest property boundary to the nearest school, residence, office building or occupied structure, excluding the immediate facility complex be greater than one (1.0) km? (20.2.72.301.B.6.a NMAC)	☐Yes ☐No	
2	Will the distance from the nearest property boundary to the nearest state park, Class II wilderness or wildlife refuge, historic park, state recreation area be greater than three (3.0) km? (20.2.72.301.B.6.b NMAC) The Air Dispersion Modeling Guidelines[1], Table: List Of State Parks, Class II Wilderness Areas, Class II National Wildlife Refuge, National Historic Parks, State Recreation Areas, and Class I Areas contains a list of most of these areas in New Mexico, but may not include new areas designated since the modeling guidelines were published.	☐Yes ☐No	
3	Will the distance from the nearest property boundary to the nearest community with a population of more than 20,000 people be greater than three (3.0) km? (20.2.72.301.B.6 NMAC).b	☐Yes ☐No	
4	Will the distance from the nearest property boundary to the nearest community with a population of more than 40,000 people be greater than 10 km? (20.2.72.301.B.6.c NMAC)	☐Yes ☐No	
5	Will the distance from the nearest property boundary to the nearest Class I area be greater than 30 km? (20.2.72.301.B.6.d NMAC) The Air Dispersion Modeling Guidelines[1], Table: List Of State Parks, Class II Wilderness Areas, Class II National Wildlife Refuge, National Historic Parks, State Recreation Areas, and Class I Areas contains a list of most of these areas in New Mexico, but may not include new areas designated since the modeling guidelines were published.	☐Yes ☐No	
6	Will the distance from the nearest property boundary to Bernalillo County be greater than 15 km? (20.2.72.301.B.7 NMAC)	☐Yes ☐No	-NA-
7	Is the answer to all of the above question yes or N/A? If the answer to **this** question is "**No**", this facility does not qualify for a streamline permit.	☐Yes ☐No	-NA-

[1] The Air Dispersion Modeling Guidelines contain a section on streamline permitting. The table mentioned above can be found within those guidelines at http://www.nmenv.state.nm.us/aqb/modeling.

18-D: Source Category Determination			
1	Is the total potential to emit of each regulated contaminant from all sources at the facility less than 40 tpy?	☐ Yes ☐ No	• If the answers to this question is "Yes", the facility qualifies for a 20.2.72.301.D.1 NMAC streamline permit. • Public notice is not required, 20.2.72.303.A NMAC. • Modeling is **not** required, 20.2.72.301.D NMAC. • If "Yes", leave the remainder of this table blank.
2	Is the total potential to emit of each regulated contaminant from all emission sources at the facility less than 100 tons per year (tpy) **AND** the impact on ambient air from all sources at the facility less than the ambient significance levels in 20.2.72.500 NMAC?	☐ Yes ☐ No	• If the answer to this question is "Yes", the facility qualifies for a 20.2.72.301.D.2 NMAC streamline permit. • Public notice is not required, 20.2.72.303.A NMAC. • **Modeling is required** in accordance with 20.2.72.301.D.2 NMAC • If "Yes", leave the remainder of this table blank.

3.a	Is the total potential to emit of each regulated contaminant from all emission sources at the facility less than 200 tons per year (tpy) **AND** the maximum modeled ambient impact from the total potential emissions at the facility less than 50 percent of each applicable PSD increment, state and federal ambient air quality standards?	☐ Yes ☐ No	• If the answers to these questions (3.a, 3.b, 3.c, and 3.d) are all "Yes", the facility qualifies for a 20.2.72.301.D.3 NMAC streamline permit. • Public notice is required in accordance with NMAC 20.2.72.303 NMAC. • **Modeling is required** in accordance with 20.2.72.301.D.3 NMAC • If the answers to questions 1, 2, and any of questions in question 3 (3.a, 3.b, 3.c, or 3.d) are "No", this facility does not qualify for a streamline permit.
3.b	Are there no adjacent sources emitting the same regulated air contaminant(s) as the source within 2.5 km of the modeled nitrogen dioxide (NO2) impact area?	☐ Yes ☐ No	
3.c	Is the "sum of the potential emissions for oxides of nitrogen from all adjacent sources" (SUM) within 15 km of the NO2 impact area (SUM15) less than 740 tpy?	☐ Yes ☐ No	
3.d	Is the "sum of the potential emissions for oxides of nitrogen from all adjacent sources" (SUM) within 25 km of the NO2 impact area (SUM25) less than 1540 tpy?	☐ Yes ☐ No	

Note: All modeling demonstrations have the option of demonstrating compliance with 20.2.72.301.D.3 NMAC. All public notices are required to comply with the public notice requirements of a NMAC20.2.72.301.D.3 facility.

18-E: Submittals

1	If a facility is required to submit a modeling analysis to demonstrate compliance with NMAC 20.2.72.300-399, use the Department's most current version of the Departments Air Dispersion Modeling Guidelines, and include a copy of the modeling in the application. A copy of the most current version of the guidelines can be obtained at the following web address: http://www.nmenv.state.nm.us/aqb/modeling.
2	**Public Notice:** Per 20.2.72.303.A NMAC, public notice is only required for sources subject to NMAC 20.2.72.301.D.3. Public notice submittals shall consist of the following: 1. Proof of Public Notice 2. Include a copy of the certified letter receipts (Field office & Federal Land Managers) (20.2.72.206.A.7, 302.A & 302.12) 3. A copy of the letters sent to the appropriate federal land manager if the source will locate within 50 km of a boundary of a Class I area (302.A.2) 4. A statement stating a complete copy of the application and public notice has been provided to the Departments field or district office nearest the source (302.A.1) 5. The location where the public notice has been posted on the site (303.B.2) 6. A copy of the classified or legal ad and its affidavit of publication (303.B.1)

Section 19

Requirements for Title V Program

Do not print this section unless this is a Title V application.

Who Must Use this Attachment:

* Any major source as defined in 20.2.70 NMAC.
* Any source, including an area source, subject to a standard or other requirement promulgated under Section 111 - Standards of Performance for New Stationary Sources, or Section 112 Hazardous Air Pollutants, of the 1990 federal Clean Air Act ("federal Act"). Non-major sources subject to Sections 111 or 112 of the federal Act are exempt from the obligation to obtain an 20.2.70 NMAC operating permit until such time that the EPA Administrator completes rulemakings that require such sources to obtain operating permits. In addition, sources that would be required to obtain an operating permit solely because they are subject to regulations or requirements under Section 112(r) of the federal Act are exempt from the requirement to obtain an Operating Permit.
* Any Acid Rain source as defined under title IV of the federal Act. The Acid Rain program has additional forms. See http://www.nmenv.state.nm.us/aqb/index.html. Sources that are subject to both the Title V and Acid Rain regulations are encouraged to submit both applications simultaneously.
* Any source in a source category designated by the EPA Administrator ("Administrator"), in whole or in part, by regulation, after notice and comment.

To save paper and to standardize the application format, delete this sentence, and begin your submittal for this item here.

19.1 - 40 CFR 64, Compliance Assurance Monitoring (CAM) (20.2.70.300.D.10.e NMAC)

Any source subject to 40CFR, Part 64 (Compliance Assurance Monitoring) must submit all the information required by section 64.7 with the operating permit application. The applicant must prepare a separate section of the application package for this purpose; if the information is already listed elsewhere in the application package, make reference to that location. Facilities not subject to Part 64 are invited to submit periodic monitoring protocols with the application to help the AQB to comply with 20.2.70 NMAC. Sources subject to 40 CFR Part 64, must submit a statement indicating your source's compliance status with any enhanced monitoring and compliance certification requirements of the federal Act.

To save paper and to standardize the application format, delete this sentence, and begin your submittal for this item here.

19.2 - Compliance Status (20.2.70.300.D.10.a & 10.b NMAC)

Describe the facility's compliance status with each applicable requirement at the time this permit application is submitted. This statement should include descriptions of or references to all methods used for determining compliance. This statement should include descriptions of monitoring, recordkeeping and reporting requirements and test methods used to determine compliance with all applicable requirements. Refer to Section 2, Tables 2-N and 2-O of the Application Form as necessary. (20.2.70.300.D.11 NMAC) For facilities with existing Title V permits, refer to most recent Compliance Certification for existing requirements. Address new requirements such as CAM, here, including steps being taken to achieve compliance.

To save paper and to standardize the application format, delete this sentence, and begin your submittal for this item here.

19.3 - Continued Compliance (20.2.70.300.D.10.c NMAC)

Provide a statement that your facility will continue to be in compliance with requirements for which it is in compliance at the time of permit application. This statement must also include a commitment to comply with other applicable requirements as they come into effect during the permit term. This compliance must occur in a timely manner or be consistent with such schedule expressly required by the applicable requirement.

To save paper and to standardize the application format, delete this sentence, and begin your submittal for this item here.

19.4 - Schedule for Submission of Compliance (20.2.70.300.D.10.d NMAC)

You must provide a proposed schedule for submission to the department of compliance certifications during the permit term. This certification must be submitted annually unless the applicable requirement or the department specifies a more frequent period. A sample form for these certifications will be attached to the permit.

To save paper and to standardize the application format, delete this sentence, and begin your submittal for this item here.

19.5 - Stratospheric Ozone and Climate Protection

In addition to completing the four (4) questions below, you must submit a statement indicating your source's compliance status with requirements of Title VI, Section 608 (National Recycling and Emissions Reduction Program) and Section 609 (Servicing of Motor Vehicle Air Conditioners).

---

1. Does your facility have any air conditioners or refrigeration equipment that uses CFCs, HCFCs or other ozone-depleting substances? ☐ **Yes** ☐ **No**

2. Does any air conditioner(s) or any piece(s) of refrigeration equipment contain a refrigeration charge greater than 50 lbs? ☐ **Yes** ☐ **No**
   (If the answer is yes, describe the type of equipment and how many units are at the facility.)

3. Do your facility personnel maintain, service, repair, or dispose of any motor vehicle air conditioners (MVACs) or appliances ("appliance" and "MVAC" as defined at 82. 152)? ☐ **Yes** ☐ **No**

4. Cite and describe which Title VI requirements are applicable to your facility (i.e. 40 CFR Part 82, Subpart A through G.)

To save paper and to standardize the application format, delete this sentence, and begin your submittal for this item here.

19.6 - Compliance Plan and Schedule

Applications for sources, which are not in compliance with all applicable requirements at the time the permit application is submitted to the department, must include a proposed compliance plan as part of the permit application package. This plan shall include the information requested below:

A. **Description of Compliance Status:** (20.2.70.300.D.11.a NMAC)
A narrative description of your facility's compliance status with respect to all applicable requirements (as defined in 20.2.70 NMAC) at the time this permit application is submitted to the department.

B. **Compliance plan:** (20.2.70.300.D.11.B NMAC)

A narrative description of the means by which your facility will achieve compliance with applicable requirements with which it is not in compliance at the time you submit your permit application package.

C. **Compliance schedule:** (20.2.70.300D.11.c NMAC)
A schedule of remedial measures that you plan to take, including an enforceable sequence of actions with milestones, which will lead to compliance with all applicable requirements for your source. This schedule of compliance must be at least as stringent as that contained in any consent decree or administrative order to which your source is subject. The obligations of any consent decree or administrative order are not in any way diminished by the schedule of compliance.

D. **Schedule of Certified Progress Reports:** (20.2.70.300.D.11.d NMAC)
A proposed schedule for submission to the department of certified progress reports must also be included in the compliance schedule. The proposed schedule must call for these reports to be submitted at least every six (6) months.

E. Acid Rain Sources: (20.2.70.300.D.11.e NMAC)
If your source is an acid rain source as defined by EPA, the following applies to you. For the portion of your acid rain source subject to the acid rain provisions of title IV of the federal Act, the compliance plan must also include any additional requirements under the acid rain provisions of title IV of the federal Act. Some requirements of title IV regarding the schedule and methods the source will use to achieve compliance with the acid rain emissions limitations may supersede the requirements of title V and 20.2.70 NMAC. You will need to consult with the Air Quality Bureau permitting staff concerning how to properly meet this requirement.

NOTE: The Acid Rain program has additional forms. See http://www.nmenv.state.nm.us/aqb/index.html. Sources that are subject to both the Title V and Acid Rain regulations are **encouraged** to submit both applications **simultaneously**.

To save paper and to standardize the application format, delete this sentence, and begin your submittal for this item here.

19.7 - 112(r) Risk Management Plan (RMP)

Any major sources subject to section 112(r) of the Clean Air Act must list all substances that cause the source to be subject to section 112(r) in the application. The permittee must state when the RMP was submitted to and approved by EPA.

To save paper and to standardize the application format, delete this sentence, and begin your submittal for this item here.

19.8 - Distance to Other States, Bernalillo, Indian Tribes and Pueblos

Will the property on which the facility is proposed to be constructed or operated be closer than 80 km (50 miles) from other states, local pollution control programs, and Indian tribes and pueblos (20.2.70.402.A.2 and 20.2.70.7.B NMAC)?

(If the answer is yes, state which apply and provide the distances.)

To save paper and to standardize the application format, delete this sentence, and begin your submittal for this item here.

19.9 - Responsible Official

Provide the Responsible Official as defined in 20.2.70.7.AD NMAC:

Section 20

Other Relevant Information

Other relevant information. Use this attachment to clarify any part in the application that you think needs explaining. Reference the section, table, column, and/or field. Include any additional text, tables, calculations or clarifying information.

Additionally, the applicant may propose specific permit language for AQB consideration. In the case of a revision to an existing permit, the applicant should provide the old language and the new language in track changes format to highlight the proposed changes. If proposing language for a new facility or language for a new unit, submit the proposed operating condition(s), along with the associated monitoring, recordkeeping, and reporting conditions. In either case, please limit the proposed language to the affected portion of the permit.

The Emission Limits for NO_x and Sulfuric Acid are Unachievable

The NO_x and Sulfuric Acid emission limitations proposed in this permit application comply with EPA's *Federal Implementation Plan [FIP] for Interstate Transport of Pollution Affecting Visibility and Best Available Retrofit Technology Determination*, 76 Fed. Reg. 52388 (Aug. 22, 2011), promulgated at 40 C.F.R. § 52.1628. However, for the reasons summarized below, the NO_x and Sulfuric Acid emission limitations required by the FIP are unachievable. As such, even with good air pollution control practices and state-of-the-art pollution control equipment, PNM expects exceedances of these limits to be unavoidable in the future.

Nitrogen Oxides

The FIP contains the following NO_x emission limitation for each unit:

> 0.05 [lbs/MMBtu], as averaged over a rolling 30 boiler-operating-day period. The hourly NO_x and O_2 data used to determine the NO_x emission rates shall be in compliance with the requirements in part 75 of this chapter. For each unit on each boiler-operating-day, the hourly NO_x emissions measured in lbs/MMBtu, shall be averaged over the hours the unit was in operation to obtain a daily boiler-operating-day average. Each day, the 30-day-rolling average NO_x emission rate for each unit (in lbs/MMBtu) shall be determined by averaging the daily boiler-operating-day average emission rate from that day and those from the preceding 29 days.

This NO_x emission limit is unachievable because even a perfectly-functioning SCR could not ensure continuous compliance with the limit. Following EPA's adoption of the FIP NO_x emission limit, PNM conducted an achievability analysis of historical data using conservative assumptions to determine how many exceedances of the limit would have occurred even if an SCR had already been in place and functioning in an ideal manner. Specifically, PNM collected all of the NO_x data reported to EPA under the Acid Rain Program since the installation of the NO_x combustion controls in 2009 and assumed that the SCR would function perfectly by continuously achieving the vendor guarantee of 0.03 lb/mmBtu for all inlet concentrations of below 0.30 lb/mmBtu and 90% removal at all inlet concentrations above 0.30 lb/mmBtu. This assumption is overly conservative (*i.e.*, tending to result in lower estimated NO_x emission rates solely for the purpose of the achievability analysis) because vendor guarantees do not provide any assurance of long-term performance, given that vendor guarantees end once a single short-term test is completed. The assumed guarantee of 0.03 lb/mmBtu is also the lowest commercially available SCR NO_x guarantee available in the United States.

In addition, since the NO_x limit applies even during startup, the analysis also took into account startups using a software model to determine unit startup characteristics. The assumptions used to determine startup emissions were also conservative due to the application of the Part 75 "diluent cap," which tends to reduce NO_x emission rate values, particularly at low-load operation during startup. Although resulting in conservatively low NO_x emission rate values, the use of the diluent cap was considered appropriate since, as noted above, compliance with the FIP NO_x emission limit must be in accordance with Part 75.

The results of the achievability analysis described above indicate that, *even with four perfectly-functioning SCRs, SJGS would have violated the FIP NO_x limit 138 times in the past*, specifically during the period of January 1, 2009 through June 30, 2011. Because the analysis above assumes a perfectly-functioning SCR, and PNM has no reason to expect future inlet concentrations to differ from the historical data utilized in the analysis, the FIP NO_x emission limit is clearly unachievable.

The adoption of the unachievable limit was the result of three flaws made by EPA during the development of the FIP. First, the analysis underlying the NO_x limit failed to take into account the natural variability inherent in the emission characteristics of the units. Second, the analysis underlying the limit failed to take into account the number, duration, and emission characteristics of startup periods at SJGS. Higher NO_x emissions during startup are unavoidable because the SCR does not become fully effective until inlet gases reach 580 degrees F, expected to be approximately 40% load, and EPA's analysis failed to take into account realistic assumptions regarding the frequency and duration of startups. Third, the averaging method required by the FIP weights more heavily those hourly emission rates that are recorded on days of partial operation because each daily average counts equally in the average, regardless of the number of operating hours in the day. Since days of partial operation generally include a startup event (and thus higher emission rates), weighting startup hours more heavily for those days results in average emissions that are biased high.

Additional analyses conducted by PNM indicate that the ability of SJGS to demonstrate compliance with a 0.05 lb/mmBtu NO_x emission limit could be improved through the use of a more appropriate averaging method (such as the method EPA recently adopted in its revision of the New Source Performance Standard applicability to electric utilities) or through facility-wide averaging (such as the averaging option EPA included in its recently adopted Mercury and Air Toxics Standards for electric utilities). However, the current FIP NO_x emission limit proposed by this permit application will remain unachievable until either (i) the limit is increased, (ii) startup emissions are excluded from the emission limit and addressed via work practice standards, and/or (iii) significant changes are made to the averaging method required for demonstrating compliance.

Sulfuric Acid

The FIP contains the following Sulfuric Acid emission limitation for each unit:

> 2.6×10^{-4} lb/MMBtu on an hourly basis. … Emissions of H_2SO_4 shall be measured within 180 days of start up of the NO_x control device and annually thereafter using EPA Test Method 8A (CTM-013).

This sulfuric acid emission limit is unachievable because it is significantly below the detection limit of the test required for demonstrating compliance and thus fails to properly account for measurement imprecision.

The "minimum detection limit" (MDL) of "EPA Test Method 8A (CTM-013)" is 0.50 mg/m^3, which translates to roughly 6.0×10^{-4} lb/mmBtu. The FIP sulfuric acid emission limit of 2.6×10^{-4} lb/mmBtu is therefore less than half of the MDL of the test method required by the FIP. Moreover, the MDL of a given test method is still far below the level at which meaningful measurements can be made. That level, often referred to as the "limit of quantification," is generally five to ten times higher than the MDL, depending on the quality of the test. EPA has recognized and applied the "limit of quantification" concept many times, most recently in the context of its Mercury and Air Toxics Standard, in which it stated the following: "[M]easurements made at or below MDL generally indicate the presence, but not the exact quantity, of a substance." 76 Fed. Reg. 24976, 25023, 25044 (May 3, 2011).

Since the FIP sulfuric acid emission limit is less than half the MDL of the required test method, it is unachievable. To reach the point at which emissions can be accurately measured, PNM estimates that the sulfuric acid mist emission limit would need to be at least five to ten times the MDL of Test Method 8A (CTM-013), or approximately 0.003 – 0.006 lb/mmBtu. Any lower limit would be below the limit of quantification, and thus fail to account for the imprecision inherent in the test method.

Several flaws in EPA's analysis led to the adoption of this unachievable sulfuric acid emission limit. The most significant error arose from EPA's reliance on the EPRI sulfuric acid emissions model. Because the EPRI model was designed for the purpose of developing emissions inventories, and not for the purpose of establishing an enforceable emission limit, it lacks sufficient accuracy and fails to address typical unit operating variability and measurement uncertainty. EPRI acknowledges that the accuracy of its model is limited due to a variety of factors and estimates that the combined uncertainties result in a relative accuracy of ± 50 percent. However, EPA failed to address this uncertainty in its analysis. In addition, EPA failed to properly apply the model to SJGS by assuming the incorrect type of coal. Although some characteristics of the San Juan coal utilized at SJGS resemble subbituminous coals, it is the alkalinity of the coal that matters most for purposes of the applying the EPRI model. In that respect, the San Juan coal is much more similar to western bituminous coals than the coal assumed by EPA in applying the EPRI model to SJGS.

Because EPA inappropriately applied an insufficiently accurate model to develop the sulfuric acid emission limit for SJGS, and because that limit is below the limit of quantification of the test method required for demonstrating compliance with the FIP, PNM considers the FIP sulfuric acid emission limit to be unachievable.

Section 21

Addendum for Landfill Applications

Do not print this section unless this is a landfill application.

Landfill Applications are not required to complete Sections 1-C and 1-E. All other Sections are required.

21-A: Landfill Information

1	How long will the landfill be operated?		
2	Maximum operational hours per year:		
3	Landfill Operating hours (open to the public) M-F:	Sat.	Sun.
4	Landfill Design Capacity (Tons):	Megagrams:	Cubic meters:
5	Landfill NMOC Emission Rate	☐ Less than 50mg/year	☐ Greater than 50mg/year
6	Annual Waste Acceptance Rate:		
7	Is Petroleum Contaminated Soil Accepted?	If so, what is the annual acceptance rate?	
8	NM Solid Waste Permit No.:	SW Permit Date:	
9	Describe NM Solid Waste Permit, Status, and Type of waste deposited at landfill		
10	Describe briefly any process(es) or any other operations conducted at the landfill		

21-B: NMOC Emissions

1	NMOC Emissions based on LandGEM:
2	Tier 1:
3	Tier 2:
4	Tier 3:

EMISSIONS (refer to 40 CFR 60.754 for test methods and procedures or AP-42 Sect.2.4)
Include the latest LandGEM calculations and/or testing results.
Facilities that have a Landfill GCCS complete the following section.

21-C: Landfill Gas Collection and Control System (GCCS) Design Plan		Yes	No
1	Was the GCCS design certified by a P.E?		
2	Was the Design System Plan submitted within 12 months of the first report of the site exceeding 50Mg/yr?		
3	Is the GCCS planned to be operational within 30 months of the first report of the site exceeding 50 Mg/yr?		
4	Does the GCCS comply with the 2 year/5 year rule?		
5	Is the design life of the GCCS more than 15 years?		
6	Have measures been taken in the GCCS Plan to control lateral gas migration?		
7	If the GCCS design is for a passive system (non enhanced), are the necessary liners in place?		
8	Is adequate density of collectors planned?		
9	Is the Landfill gas conveyance system sized properly?		
10	Is the landfill gas planned to be routed to a control device? (Utility flare, enclosed flare or other)		
11	If the control device is a flare, does it include continuous temperature monitoring and a flow measurement device?		
12	Is the flare sized properly?		
13	Does the GCCS include fittings to allow connection of additional collectors if necessary in the future?		
14	Does the wellhead for all collectors include at least one sample port and one thermometer port?		
15	Operational Issues: 1. Will the GCCS be operated at a vacume at every well? 2. Will the GCCS be operated at the appropriate gas temps? 3. Will the GCCS be operated with minimal amounts of air? 4. Will monitoring be done monthly to conform with these operational issues? 5. Will surface emissions monitoring be completed? 6. Will the blower automatically be shut down if the control device is inoperable?		
16	Was the design diagram for the GCCS, including the flare, blower, and well location attached to the permit application?		

Section 22

Green House Gas Applicability

(submitting under 20.2.70, 20.2.72, 20.2.73, 20.2.74 NMAC)

Title V (20.2.70 NMAC), NSR (20.2.72 NMAC), NOI (20.2.73 NMAC) and PSD (20.2.74 NMAC) applicants must determine if they are subject to Title V permitting and/or PSD permitting for green house gas (GHG) emissions. GHG emissions are the sum of the aggregate group of six green house gases that include carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). There are two thresholds that must be computed to determine applicability. The first threshold is the sum of GHG mass emissions in TPY. GHG mass emissions are the sum of the total annual tons of green house gases without adjusting with the GWPs. The second threshold is the sum of CO_2 equivalent (CO_2e) emissions in TPY GHG. CO_2e emissions are the sum of the mass emissions of each individual GHG multiplied by its global warming potential (GWP) found in Table A-1 in 40 CFR 98 Mandatory Greenhouse Gas Reporting.

Green House Gas TV and PSD Applicability Determination:

☐ **Notice of Intent Sources** (20.2.73 NMAC): By checking this box and certifying this application the applicant certifies that the facility, based upon the quantity of stack emissions, including start up, shut down, and maintenance emissions, is not subject to 20.2.70 NMAC or 20.2.74 NMAC for Green House Gas (GHG) Emissions. The Department may request the emissions calculations and other documents supporting this determination.

Minor NSR (20.2.72 NMAC), PSD Major (20.2.74 NMAC), and Title V (20.2.70 NMAC) sources must complete the steps outlined below to determine GHG TV and/or PSD applicability.

1. Calculate existing mass GHG and CO_2e emissions from your source. For PSD purposes, if this is a modification to an existing source, you must also calculate the increase in mass GHG and CO_2e emissions due to the modification. Start up, shut down, and maintenance emissions must be included.
2. See Tables 1 and 2 below and compare your mass GHG and CO_2e emissions to the appropriate category for your source.
3. If your source meets all of the criteria within a category, then you must obtain a PSD permit and/or a Title V permit for green house gas emissions.
4. If this is a GHG Major source with an existing BACT or if this is a permit application for a PSD or Title V permit with GHG above the thresholds in Tables 1 or 2, include the emissions calculations and supporting documents in the appropriate sections of this application unless instructed otherwise in Tables 1 or 2. Report GHG mass and CO_2e emissions in Table 2-P of this application unless instructed otherwise in Tables 1 or 2. Emissions are reported in **short** tons per year and represent each emission unit's Potential to Emit (PTE).

NSR (20.2.72 NMAC), PSD Major (20.2.74 NMAC), and Title V (20.2.70 NMAC): Based upon the GHG applicability criteria in this section the applicant certifies that the source is (check all that apply):

☐ Title V Minor and PSD Minor for GHG Emissions [The Department may request the emissions calculations and other documents supporting this determination.]

☐ Title V Major for GHG Emissions

☐ PSD Major for GHG Emissions

Table 1 - Title V Applicability Criteria		
On or after July 1, 2011, newly constructed source, or existing source that does not have a Title V permit	**On or after July 1, 2011, modification or Renewal to Existing Title V Source**	**Requirement**
Source emits or has potential to emit (PTE) ≥ 100,000 TPY CO_2e **and**	Source emits or has PTE of ≥100,000 TPY CO_2e **and** 100 TPY GHG mass basis	**For new sources:** For a source that meets the criteria on July 1, 2011, submit a Title V permit application no

Table 1 - Title V Applicability Criteria		
100 TPY GHG mass basis		later than June 30, 2012. For a source that meets the criteria after July 1, 2011, submit a Title V application within 12 months of becoming subject to the GHG operating permit program (12 months from commencement of operation of the new unit or modification that caused the source to be subject to Title V). **For existing sources:** Include GHG with the next Title V application for a renewal or modification. **For both new and existing sources:** Include in the TV application, GHG emissions calculations and supporting documents, report CO_2e and GHG emissions in Table 2-P, and address any applicable CAA requirements (e.g. PSD BACT, NSPS). If there are no applicable requirements and if GHG emissions have been reported to the Department under 20.2.73 NMAC, the requirements of the previous sentence do not apply, but changes in GHG emissions resulting in GHG emission limits must be calculated and reported in Table 2-P for Title V permit modifications. Typically GHG emission limits would be established only when there is an applicable requirement, such as a PSD GHG BACT or limits taken to be GHG synthetic minor.

Table 2 - PSD Applicability Criteria			
On or After July 1, 2011, New Source	**On or After July 1, 2011, Major Modification to Existing PSD Major Source**	**On or After July 1, 2011, Modification to Existing PSD Minor Source**	**Requirement**
Source is subject to PSD for another pollutant **and** GHG PTE is ≥ than 75,000 tpy CO_2e **or** GHG PTE is ≥ 100,000 TPY CO_2e **and** ≥ 100/250 TPY mass basis	Source is subject to PSD for another regulated pollutant **and** net GHG emissions increase is ≥ 75,000 tpy CO_2e and greater than zero TPY mass basis **or** existing source has GHG PTE ≥ 100,000 TPY CO_2e **and** ≥ 100/250 TPY mass basis **and** net emissions GHG increase is ≥ 75,000 TPY	Actual or potential emissions of GHGs from the modification is ≥ 100,000 TPY CO_2e **and** ≥ 100/250 TPY mass basis. Minor PSD sources cannot net out of PSD review.	The source is subject to PSD permitting for GHG emissions and other regulated pollutants that are significant. In the application include GHG emissions calculations and supporting documents, report CO_2e and GHG emissions in Table 2-P, complete a GHG BACT determination, and include the TPY CO_2e and GHG mass emissions in the public notice. **Note:** If a minor source permit is issued after January 2, 2011, but before July 1, 2011, and construction has not commenced by July 1, 2011, the permit must be cancelled,

Table 2 - PSD Applicability Criteria			
	CO_2e and greater than zero TPY mass basis		reopened, or an additional PSD permitting action taken, if the approved change/construction would trigger GHG PSD after July 1, 2011.

Additional Information:

Sources for Calculating GHG Emissions:

- Manufacturer's Data
- AP-42 Compilation of Air Pollutant Emission Factors at http://www.epa.gov/ttn/chief/ap42/index.html
- EPA's Internet emission factor database WebFIRE at http://cfpub.epa.gov/webfire/
- Subparts C through UU of 40 CFR 98 Mandatory Green House Gas Reporting except that tons should be reported in short tons rather than in metric tons for the purpose of PSD and TV applicability.
- API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry. August 2009 or most recent version.
- Sources listed on EPA's NSR Resources for Estimating GHG Emissions at http://www.epa.gov/nsr/ghgresources.html:
  - ENERGY STAR Industrial Sector Energy Guides and Plant Energy Performance Indicators (benchmarks) http://www.energystar.gov;
  - US EPA National Greenhouse Gas Inventory, http://epa.gov/climatechange/emissions/usinventoryreport.html;
  - EPA's Climate Leaders, http://www.epa.gov/climateleaders/index.html
  - EPA Voluntary Partnerships of GHG Reductions that include the landfill methane outreach program, the CHP partnership program, the Green Power Partnership, the Coalbed Methane Outreach program, the Natural Gas STAR program, and the Voluntary Aluminum Industrial Partnership.
  - SF Emission Reduction Partnership for the Magensium Industry http://www.epa.gov/highgwp/magnesium-sf6/index.html
  - PFC Reduction/Climate Partnership for the Semiconductor Industry http://www.epa.gov/highgwp/semiconductor-pfc/index.html

Global Warming Potentials (GWP):
Applicants must use the Global Warming Potentials codified in Table A-1 of the most recent version of 40 CFR 98 Mandatory Greenhouse Gas Reporting. Please note that sources not subject to 40 CFR 98 and/or 20.2.300 NMAC may still be subject to the GHG PSD and/or TV permitting. The GWP for a particular GHG is the ratio of heat trapped by one unit mass of the GHG to that of one unit mass of CO_2 over a specified time period.

"Greenhouse gas" for the purpose of this part is defined as the aggregate group of the following six gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. **(20.2.70.7.O NMAC, 20.2.74.7.Y NMAC).** You may also find GHGs defined in 40 CFR 86.1818-12(a).

Short Tons:
Short tons for GHGs and other regulated pollutants are the standard unit of measure for PSD and title V permitting programs. 40 CFR 98 Mandatory Greenhouse Reporting requires metric tons.
1 metric ton = 1.10231 short tons (per Table A-2 to Subpart A of Part 98 – Units of Measure Conversions)

EPA's GHG Tailoring Rule:
To review EPA's final GHG Tailoring rule and pre-amble, See "Final GHG Tailoring Rule dated May 13, 2010 located on EPA's NSR Regulations Webpage or Federal Register June 3, 2010 Volume 75, No. 106
http://www.epa.gov/nsr/actions.html

EPA Permitting Guidance:
EPA's Permitting Guidance for GHG and other GHG information can be found on EPA's NSR Clear Air Act Permitting for Greenhouse Gases webpage.
http://www.epa.gov/nsr/ghgpermitting.html

Section 23: Certification

Company Name: _____

I, _____, hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this ____ day of _____, _____, upon my oath or affirmation, before a notary of the State of

_____.

_____ _____
*Signature Date

_____ _____
Printed Name Title

Scribed and sworn before me on this ____ day of _____, _____.

My authorization as a notary of the State of _____ expires on the

_____ day of _____, _____.

_____ _____
Notary's Signature Date

_____
Notary's Printed Name

*For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AD NMAC.