PNM EXHIBIT RND-5

Consisting of 28 pages

PNM Exhibit RND-5
Consisting of 28 Pages

Statement of Basis - Narrative
NSR Permit

Company: Public Service Company of New Mexico (PNM)
Facility: PNM - San Juan Generating Station
Permit No(s).: 0063-M8 and P062R2M2
Tempo/IDEA ID No.: 1421 - PRN20120001
Permit Writer: Joseph Kimbrell

Fee Tracking (not required for Title V)

Tracking	**NSR tracking entries completed:** [X] Yes [] No
	NSR tracking page attached to front cover of permit folder: [X] Yes [] No
	Paid Invoice Attached: [X] Yes [] No
	Balance Due Invoice Attached: [] Yes [X] No
	Invoice Comments: Invoice paid on 6/17/2012

Permit Review	**Date to Enforcement:** 8/7/12	**Inspector Reviewing:** Robert Samaniego
	Date Enf. Review Completed: 8/24/12	**Date of Reply:** (if necessary)
	Date to Applicant: 8/7/12	**Date of Reply:** 8/29/12
	Date of Comments from EPA: N/A	**Date to EPA:** N/A
	Date to Supervisor: Final 8/30/2012	

1.0 Plant Process Description:

PNM SJGS is a coal-fired electric generating station located approximately 3 miles north-northeast of Waterflow, New Mexico. The facility consists of four coal-fired boilers (Units 1-4) which burn coal received by conveyors from the adjacent San Juan Mine to generate high-pressure steam that powers a steam turbine coupled with an electric generator. Electric power thus produced by the units is supplied to the electric power grid for sale. This is a pulverized coal fired power plant with 4 boilers. The boilers began operations in 1976, 1973, 1979, and 1982.

2.0 Description of this Modification:

This modification 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, some permit modifications are common to both scenarios. Combine AUX 1 and 2 into Unit E410 and delete Unit E411.For Scenario A: add Units E520, E521, and E522.

<u>Construction Options</u>

A. 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.

B. Permitting changes/updates to Scenario A (FIP) only:

(1) 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) 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. The SCR shall be designed to achieve a maximum 2 ppmvd ammonia slip.

(3) 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) New boiler stack emission limits for NOx emissions (0.05 lb/mmBtu 30-boiler operating day rolling average) and H_2SO4 (2.6 X 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) 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.

(6) EPA extended the time for compliance with the emission limits from 3 years to 5 years, the maximum period allowed by the Clean Air Act. Therefore, SCR shall be installed on each of the four units as expeditiously as practicable, but in no event later than 5 years from the effective date of our final rule. The Federal register date was August 22, 2011. Installation of all control equipment and compliance with new emission limits shall be not later than August 20, 2016.

C. Permitting changes/updates to Scenario B (SIP) only:

(1) 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) 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. The SNCR shall be designed to achieve a maximum 10 ppmvd ammonia slip.

(3) 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) 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.

(5) In accordance with 40 CFR 51.308(e)(1)(iv), the Department determined that SNCR shall be installed on each of the four units as expeditiously as practicable,

but in no event later than 5 years after approval by the EPA of the SIP. As of July 6, 2012, EPA has not approved the SIP.

D. 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.

3.0 Source Determination:

1. The emission sources evaluated include **San Juan Generating Station**.

2. Single Source Analysis:

A. SIC Code: Do the facilities belong to the same industrial grouping (i.e., same two-digit SIC code grouping, or support activity)? Yes

B. Common Ownership or Control: Are the facilities under common ownership or control? No

C. Contiguous or Adjacent: Are the facilities located on one or more contiguous or adjacent properties? Yes

3. Is the source, as described in the application, the entire source for 20.2.70, 20.2.72, or 20.2.74 NMAC applicability purposes? Yes

4.0 **PSD Applicability:**

This facility is an existing PSD Major Source. SJGS is a major source under both 20.2.70 NMAC (Title V) and under 20.2.74NMAC (PSD). SJGS has a Title V Operating Permit, but does not have a 20.2.74 NMAC (PSD) permit as the facility was constructed prior to applicability of 20.2.74NMAC and has not undergone a major modification as of the date of the last NSR permitting action, see history table.

A. The source, as determined in 3.0 above, is **an existing PSD Major Source.**
B. The project emissions for this modification are **not significant. Action is reducing NOx emissions; however, there will be an insignificant increase in H2SO4, CO2 and PM.**

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 "aggregated" calculation below confirms that the installation and operation of SCR systems at SJGS will not result in a significant emissions increase of H_2SO_4.

Baseline Actual Emissions *(average of 2008 and 2009 TRI reports submitted to NMED)*	**Potential Emissions** *(based on H_2SO_4 limit in the FIP at 100% capacity for 8,760 hrs/year)*	**Change in H_2SO_4 Emissions**	**H_2SO_4 PSD Significance Threshold**
22.7 tpy	21.6 tpy	**– 1.1 tpy**	7 tpy

This calculation is consistent with the federal and New Mexico PSD regulations. The definition of "baseline actual emissions" allows use of "any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project" (20.2.74.7G.(1) NMAC). Unlike the rules applicable to all other types of stationary sources, the emission calculation rules for "electric utility steam generating units" do not require a downward adjustment for new emission limitations (*compare* 20.2.74.7G.(1) NMAC *with* 20.2.74.7G.(2) NMAC). Because actual construction of the SCR is scheduled to begin this fall, the look-back period for this analysis stretches from November 2007 through October 2012. As such, the baseline calculation above is based on the average of the annual H_2SO_4 emission rates submitted to EPA in the 2008 and 2009 TRI reports. The "baseline actual emissions" are compared to the "projected actual emissions," which according to 20.2.74.7 (AR)(4) NMAC, may be calculated based on each unit's potential to emit. The "baseline actual emissions" are 1.1 tpy below the future projected "potential" emissions, assuming the FIP emission limit for H_2SO_4 of 0.00026 lb/mmBtu and operation at a 100% capacity factor using each unit's maximum hourly heat input rating (3,707 mmBtu/hr for Units 1 & 2 and 5,758 mmBtu/hr for Units 3 & 4). This calculation reflects both the decrease in H_2SO_4 emission rates achieved through elimination of the scrubber bypass and the installation of a fabric filter baghouse (both of which were required by the 2005 Consent Decree and installed over time between 2007 and 2009) and operation of the SCRs with a low-oxidation catalyst. Because this calculation results in a net decrease in H_2SO_4 emissions, the SCRs do not trigger PSD. The Units will also be equipped with a dry sorbent injection system (DSI) that will be used as necessary to comply with the FIP emission limit. In addition, since this analysis utilizes the "actual-to-potential" method of calculating future emissions, the SCRs do not trigger the PSD recordkeeping or reporting requirements of 20.2.74.300E NMAC.

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.

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.

C. Netting **is not required (project is not significant).**
D. BACT is **not required for this modification (minor Mod).]**

5.0 **<u>History (In descending chronological order, showing NSR and TV):</u>** *The asterisk denotes the current active NSR and Title V permits that have not been superseded.

Permit Number	Issue Date	Action Type	Description of Action (Changes)
0063M8	08/31/12	Significant Revision	Application was submitted on April 6, 2012 to modify the facility for SCR or SNCR in accordance with EPA-FIP or NM SIP. Even though the FIP is being challenged in court, PNM must proceed with the application to allow time to get permit issued and 5-year for construction and still meet EPA's construction deadline in the FIP. If the EPA FIP is overturned by the court, the NM SIP with SNCR will be implemented.
0063M7	12/14/11	Significant Revision	The modification consisted of adding a permit limit for Total PM-2.5 (filterable plus condensable PM2.5), increasing the facility-wide annual diesel fuel usage, and revising the Duct leak PM-2.5 calculations based on available PM-2.5 size fraction information. No increase in emission limits are being added.
0063M6R2	5/16/11	Tech Rev	Reduces the sulfur dioxide (SO2) emission limits for the four main boilers to 0.015 lb/MMBtu and reduces the total SO_2 annual emissions. Convert NSR Permit to new Table format to match Title V permit was not accomplished over objection from PNM. **PSD Applicability**: This facility is an existing PSD Major Source. The project emissions for this modification are not significant. Netting is not required (project is not significant). BACT is not required for this modification (minor Mod).
P062R2M1	3/28/2011	Admin Rev	Corrected Typo error, added correct Reporting Schedule at Condition A109.A and B.
*P062R2 & P062AR2	1/24/2011	Renewal	Renewal of Operating and Acid Rain Permits and includes modification authorized by NSR 0063M4 thru 63M6R1. Removal of emergency generator from permit condition since there meet the definition of emergency generators and insignificant activities. Convert to new Table permit format.
*0063M6R1	9/12/2008	Tech Rev	SJGS is proposing to add fabric filters Units S518 and S519 (baghouses) to the existing Unit 1 and Unit 2 fly ash silos (one silo per unit). These fabric filters will replace control provided by the current ESPs and will be provide more efficient PM control than the current ESPs. **PSD Applicability**: This facility is an existing PSD Major Source. The project emissions for this modification are not significant. Netting is not required (project is not significant). BACT is not required for this modification (minor Mod).
*0063-M6	4/22/2008	Significant Revision	This modification consists of revising the permit to impose as enforceable permit conditions that limit the amount of particulate emitted into the air from the activities associated with delivery and injection of activated carbon into the combustion exhaust of each boiler. The activated carbon is used to control mercury emissions. There will be four silos (one for each boiler) constructed. Each silo will have a baghouse. The emissions established in 0063M4 are sufficient enough to include any extra emissions originating from the carbon injection. The particulate emissions limit from the boiler stack will remain unchanged. Emissions are generated from the delivery of the activated carbon, loading activated carbon, operations of the silo, cleaning of the baghouse, and those emissions that were not captured by the boiler's baghouse. The operations of the silo require a constant stream of air to flow through the activated carbon to keep it fluid.

Permit Number	Issue Date	Action Type	Description of Action (Changes)
0063M5R1	12/5/2007	Admin Rev	This revision consists of adding an emergency Cummins Diesel generator model DSHAF located at the SJGS data center as an exempt piece of equipment.
P062R1M1	6/11/2007	Significant Revision	Incorporate NSR Permit 0063M3 conditions into body of TV. This changed the Carbon Monoxide (CO) emission rates for Units 1-4. The permit template language was updated. This was discussed with Cathy Penland of EPA Region 6 on 2/12/07. At final review stage. Richard Goodyear directed the reference to the Compliance Schedule from NSR 0063M4 in Condition 7.4 be removed since the schedule was not as a results of this facility being out of compliance IAW our State Regulations.
0063M5	Withdrawn 10/20/06	Reg. Significant Revision	Temporary pumps in the river.
0063M4	Sept 18, 2006	Reg. Significant Revision	This modification consists of adding fabric filters to each boiler, replacing the existing boiler burners with low-NOx burners, and increasing the control efficiency of the wet limestone scrubber. NSR 0063M4 includes all requirements of the March 10, 2005 Consent Decree.
0063M3	Sept. 20, 2005	Reg. Significant Revision	This modification consists of raising the carbon monoxide (CO) emissions limits for Boiler Units 1-4 to reflect the results of recent stack testing. The initial compliance testing performed on Units 1-4 in accordance with Specific Conditions in NSR 0063M2, revealed the estimated CO emissions permitted could not be met. The 1997 NSR Permit 0063M2 was for the replacement of the Limestone scrubber control system for SO2. Since the facility was so old, CO testing had never been required and the permitted CO limits had been based on calculation. As part of the Permit 63M2 PNM was required to perform CO EPA Method Test for the first time. The limestone scrubbers have nothing to do with CO emissions. So the CO method test was used to verify existing CO emissions due to NO modification to the facility. The Permit 0063M3 increased the permitted emissions from ~2,000 to ~39,000 as a result of the CO Method test.
	Mar 10, 2005 (signed 3/9/05)	Date lodged in Court	The Department and PNM consent to entry of Consent Decree without further trial or appeal. Refer to complete Consent Decree for complete history of events.
P062R1	Feb. 4, 2005	Renewal	Incorporated NSR Permit 0063M2 and 0063M2R1. This permit for first time required CO compliance Testing. Units E301, E302, E303, and E304 (boilers) are subject to periodic compliance testing for PM, TSP, PM-10, PM-2, CO, and VOC using stack tests and Unit E803 is subject to periodic compliance testing for PM using stack tests. The tests for PM, TSP, PM-10, and PM-2 on Units E301, E302, E303, and E304 (boilers) shall be performed within 6 months of issuance of this permit and annually thereafter. The tests for CO and VOC on Units E301, E302, E303, and E304 (boilers) shall be performed within 6 months of issuance of this permit and quarterly thereafter. The tests on Unit E803 shall be performed at the discretion of the Department. CO test results from May 2005 test showed permit limits exceedance and application for NSR Application developed for NSR 63M3. Next quarterly test in July 2005 showed CO levels needed to be adjusted for summer high temperatures, resulting in the permit limits

Permit Number	Issue Date	Action Type	Description of Action (Changes)
			established in NSR 63M3.
	May 26, 2004	Order entered	Found 42,008 opacity limit violations would be addressed in the remedy phase.
	May 16, 2002	Citizen Suit	Grand Canyon Trust and Sierra Club filed citizen suit against PNM alleging violations of CAA, violating the 20 % opacity emission limits for Units 1-4, and units 3 and 4 did not have a PSD permit. In the CD PNM was awarded summary judgment on the PSD issue "WHEREAS, on August 20, 2003, the Court granted PNM's motion for summary judgment on Plaintiffs' PSD claim
0063M2R1	Sept 17, 1999	Technical Revision	This revision allowed the use of a previously idle cooling tower at the facility (Emission Unit E411 in Title V Permit No. P062R1).
P062	June 28, 1998	New Title V	First Operating Permit
0063M2	Jan. 22, 1997	Reg. Significant Revision	New FGD reduced SO_2 emissions. This modification allowed for construction of limestone forced oxidation scrubbers to replace older Wellman-Lord FGD system scrubbers for SO_2 control. This NSR permit also brought the four generating units (1, 2, 3, 4) at the facility under a single NSR permit (they had previously been permitted separately). This permit supercedes all previous permits.
0063M1	Jan. 5, 1987	Modified and reissued	This permit is in response to Company Ltr dated 11/13/1986 requesting that the air quality permit for Unit 4 at the San Juan generating Station be modified and reissued to conform to the 1980 amendments to the Air Quality Control Regulation 602 regarding sulfur dioxide emission rates.
0062M1	Jan. 5, 1987	Modified and reissued	This permit is in response to Company Ltr dated 11/13/1986 requesting that the air quality permit for Unit 3 at the San Juan generating Station be modified and reissued to conform to the 1980 amendments to the Air Quality Control Regulation 602 regarding sulfur dioxide emission rates.
0013M1	Jan. 5, 1987	Modified and reissued	This permit is in response to Company Ltr dated 11/13/1986 requesting that the air quality permit for Unit 1 at the San Juan generating Station be modified and reissued to conform to the 1980 amendments to the Air Quality Control Regulation 602 regarding sulfur dioxide emission rates.
0063	Sept 15, 1975	Cert. Of Registrn.	To install Unit # 4
0062	1982	Cert. Of Registrn.	To install Unit # 3. These documents could not be located at this time, 2/1/2007.
0013	1975	Cert. Of Registrn.	To install Unit # 1. These documents could not be located at this time, 2/1/2007.
Cert. Of Registrn.	Oct. 5, 1973	Cert. Of Registrn.	To install Unit #2. These documents could not be located at this time, 2/1/2007.

6.0 **Public Response/Concerns:** As of August 30, 2012 this permit writer is not aware of any public comment or concern.

7.0 Compliance Testing:

Unit No.	Compliance Test	Test Dates
1	Tested in accordance with EPA test methods 5i for filterable PM and 202 for condensable PM2.5. Total PM2.5 is calculated as the	5/10/11

	sum of these two measurements.	
2	Tested in accordance with EPA test methods 5i for filterable PM and 202 for condensable PM2.5. Total PM2.5 is calculated as the sum of these two measurements.	4/13-14/11
3	Tested in accordance with EPA test methods 5i for filterable PM and 202 for condensable PM2.5. Total PM2.5 is calculated as the sum of these two measurements.	5/24/11
4	Tested in accordance with EPA test methods 5i for filterable PM and 202 for condensable PM2.5. Total PM2.5 is calculated as the sum of these two measurements.	5/25-26/11

8.0 Startup and Shutdown:

A. If applicable, did the applicant indicate that a startup, shutdown, and emergency operational plan was developed in accordance with 20.2.70.300.D(5)(g) NMAC? Yes

B. If applicable, did the applicant indicate that a malfunction, startup, or shutdown operational plan was developed in accordance with 20.2.72.203.A.5 NMAC? Yes

C. Did the applicant indicate that a startup, shutdown, and scheduled maintenance plan was developed and implemented in accordance with 20.2.7.14.A and B NMAC? Yes

D. Were emissions from startup, shutdown, and scheduled maintenance operations calculated and included in the emission tables? Yes

9.0 **Compliance and Enforcement Status [Title V only]: NR**

10.0 **Modeling:** For NSR 0063M8 a Modeling waiver was approved by Gi-Dong Kim on April 18, 2012 for Ammonia and H2SO4.

The proposed permitting action will significantly reduce NOx boiler stack emissions. There will also be relatively small decreases in SO2, NOx, PM and CO from elimination of the boiler duct leaks. There will be several changes to PM emission sources in addition to elimination of the duct leaks including updating truck traffic road dust estimates, addition of three baghouses on sorbent silos (Scenario A only), and significant reduction of cooling tower PM10 and PM2.5 emissions resulting from updated calculations that provide more realistic emission rates for the smaller size fractions. Overall there is a net reduction in facility PM emissions for all PM size categories. Based on previous modeling analysis, the changes to PM emissions will not increase ambient impacts.

11.0 **State Regulatory Analysis(NMAC/AQCR): No changes for this action.**

20 NMAC	Title	Applies (Y/N)	Comments
2.3	Ambient Air Quality Standards	Y	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. Defined as applicable at 20.2.70.7.E.1 NMAC
2.5	Source Surveillance	Y	Excess Emissions During Malfunction, Startup,

20 NMAC	Title	Applies (Y/N)	Comments
			Shutdown, or Scheduled Maintenance
2.7	Excess Emissions	Y	Applies to all facilities' sources
2.14	Particulate emissions from Coal Burning Equipment	Y	Particulate Emissions From Coal Burning Equipment
2.31	Coal Burning Equipment – Sulfur Dioxide	Y	Coal Burning Equipment - Sulfur Dioxide
2.32	Coal Burning Equipment – Nitrogen Dioxide	Y	Coal Burning Equipment – Nitrogen Dioxide
2.61	Smoke and Visible Emissions	Y	The coal burning equipment is exempt from 20.2.61 NMAC.
2.70	Operating Permits	Y	PTE **is** > 100 TPY, Source is major for NOx, CO, VOCs, SO2, Formaldehyde, and Total HAPs.
2.71	Operating Permit Fees	Y	PTE **is** > 100 TPY, Source is major for NOx, CO, VOCs, SO2, Formaldehyde, and Total HAPs.
2.72	Construction Permits	Y	Specify Section 200.A.2
2.73	NOI & Emissions Inventory Requirements	Y	Applicable to all facilities that require a permit.
2.74	Permits-Prevention of Significant Deterioration	Y	This facility is major for NOx, CO, TSP, PM_{10}, $PM_{2.5}$, VOC, and SO_2. Source **is** one of the 28 listed – PTE > 100 tpy This is a minor modification to a major PSD source.
2.75	Construction Permit Fees	Y	This facility is subject to 20.2.72 NMAC
2.77	New Source Performance	Y	Apples to any stationary source constructing or modifying and which is subject to the requirements of 40 CFR Part 60 subparts A, D, and OOO
2.78	Emissions Standards for HAPs,	Y	HAPS PTE > 10 for a single HAP and > 25 tpy for all combined HAPs. Therefore this facility emits hazardous air pollutants which are subject to the requirements of 40 CFR Part 61, as amended through September 1, 2001.
2.79	Permits: Nonattainment Areas	N	This facility is not located in a non-attainment area.
2.82	MACT Standards for Source Categories of HAPs.	N	
2.84	Acid Rain	Y	This facility is subject to the acid rain regulation.
2.85	Mercury Emission Standards And Compliance Schedules For Electric Generating Units	N	It is the opinion of this permit writer that this facility is subject to 20.2.85, but the future of this regulation in uncertain as of the date of this writing. 20.2.85 was not included in the permit for this reason. The TV permit writer will have a chance to revisit this at a later date.

12.0 Federal Regulatory Analysis:

Air Programs Subchapter C (40 CFR 50)	Title National Primary and Secondary Ambient Air Quality Standards	Applies (Y/N)	Comments
C	Federal Ambient Air Quality Standards	Y	Defined as applicable at 20.2.70.7.E.11, Any national ambient air quality standard

NSPS Subpart (40 CFR 60)	Title	Applies (Y/N)	Comments
A	General Provisions	Y	Applies if any other subpart applies
D	Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971	Y	
OOO	Standards of Performance for Nonmetallic Mineral Processing Plants	Y	

NESHAP Subpart (40 CFR 61)	Title	Applies (Y/N)	Comments
A	General Provisions	N	

NESHAP Subpart (40 CFR 63)	Title	Applies (Y/N)	Comments
A	General Provisions	N	Applies if any other subpart applies

NESHAP Subpart (40 CFR 76)	Title	Applies (Y/N)	Comments
Title IV – Acid Rain 40 CFR 76	Acid Rains Nitrogen Oxides Emission Reduction Program	Y	

13.0 **Exempt and/or Insignificant Equipment that do not require monitoring:**

No changes due to this permit action.
The Data Center Emergency generator is exempt since it provides power during periods of loss of commercial power.

14.0 **New/Modified/Unique Conditions** (Format: Condition#: Explanation):

15.0 Cross Reference Table between NSR Permit 0063M7 and TV Permit P062R2 is not required since both permits are now in the same format.

16.0 **Permit specialist's notes to other NSR or Title V permitting staff concerning changes and updates to permit conditions.**

A. NSR Permit 0063M8, discussion on Ammonia Slip and Ammonia emission limits for both scenarios.

The FIP initially proposed ammonia emission limits but after comments, EPA settled on no emission limit for ammonia and requiring the SCR be designed for a maximum 2 ppm ammonia slip. **NMED in this permit** will require submission of the maximum slip from PNM's design specifications and at least an initial compliance test to demonstrate that the designed system can operate at less than 2 ppm slip while complying with the NOx limits when the SCR catalyst is new. The SIP option was silent on this discussion, therefore, if the SIP option is chosen; NMED will follow the same logic as the FIP. If the measured slip from the initial compliance test (when catalyst is new) is more than 80% of the design limit, then more frequent monitoring (annual testing) will be imposed.

No additional testing or monitoring is required to ensure NMED TAP trigger for ammonia is not exceeded since the stack height adjustments to the values are well below the adjusted triggers. For SJGS the ammonia slip based on a 2 ppmv ammonia slip rate for Scenario A (SCR) and at 10 ppmv for Scenario B (SNCR). For SCR the facility ammonia slip is approximately 24.2 lbs/hr and for SNCR about 120 lbs/hr. The details of these calculations are given in Section 6 of the application. Both of these values are significantly below the NMED TAP trigger value - which for SJGS stack height is about 640 lbs/hr (1.2 lbs/hr times 533). For SCR this is a factor of 26.4 lower than the TAP trigger and for SNCR 5.3 times lower than the TAP trigger. It would take an ammonia slip rate of about 53 ppm before the TAP trigger was reached - a value that indicates ammonia use at more than 5 times(for SNCR) to 26 times (for SCR) the maximum requirement.

B. NSR Permit 0063M8, discussion on Sulfuric Acid Mist (H2SO4) limits and monitoring for scenario A (SCR) only.

The FIP includes a requirement that boiler stack sulfuric acid emissions be limited to no more than 0.00026 lbs/mmBtu.

These limits are half of the detection limit of the test method required for demonstrating compliance with the FIP (EPA Method 8A procedures). 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 the values range from 0.959 to 1.5 pph.

This emission limit is applied to each individual unit. This requirement becomes effective 5 years after the effective date of the rule or September 20, 2016.

In the FIP, considering SCR for controlling NOx, EPA specifically considered the issues of sulfuric acid formation. EPA believed that the emission limits for NOx can be achieved through the use of lower reactivity catalyst, thus mitigating the formation of sulfuric acid across the catalyst bed. EPA set an emission limit for emissions of sulfuric acid that restricts the increase of sulfuric acid. According to the two most recent Toxic Release Inventory (TRI) reports submitted by SJGS, the total sulfuric acid emissions are very low (17.77 TPY for 2009, and 27.5 TPY for 2008). Based on their calculations, EPA believed the current emissions of sulfuric acid to be significantly lower than these reported values due to the low sulfur content of the coal and the removal of sulfuric acid in the installed control equipment, including wet scrubbers and fabric filters. EPA projected, with the implementation of SCR using a low reactivity catalyst that total emissions of sulfuric acid will remain below 22 tons/year.23 In this particular case, sorbent injection technology is unlikely to be cost-effective on a cost per ton basis of sulfuric acid mist removed.

C. Permit NSR 0063M8 was updated with changes from AQBs template changes as of 6/16/2012 and includes General Condition updates to B108.D.3 and B109.B.

D. 8/30/2012, the NSR draft 0063M8 was updated based on comments from PNM date 8/29/2012 as stated here.

General Comments

- Significant Digits: In several cases emission limits in the draft permit are expressed with more significant digits than specified in NMED rule 20.2.1.116 NMAC. In many cases these are legacy values from prior permits specified prior to the rule, but there are new emission limits (such as ammonia, sulfuric acid, updated HAP totals, etc.) that are new and are specified to as many as 5 significant digits. To avoid confusion and to maintain consistency with the NMED rule PNM requests these values be changed per the rule (i.e. at least 2 but no more than 3 significant figures).

NMED Comment: We will attempt to apply the rule as we recognize them since you didn't point out any specifically. Were we show totals that are not specific emission limits, NMED normally shows totals to the tenth of a decimal, for example 248.0 or 105.9. Unless a Table states that it contains emission limits, then this doesn't apply. This rule applies to the emission limits and calculation you perform in completing Table 2-D and 2-E of the application and the specific emission limits that NMED establishes in Tables 106.

- Reference to M-8 as Requirement Source: In several places, Permit 0063-M8 is cited as the source of a requirement. This reference seems self-referential or circular and PNM recommends in these cases that the underlying applicable requirement be referenced. These cases are included in the specific comments below.

NMED Comment: The locations were NMED states the source of the requirement is for clarity and is used in the Title V permit to show the permit that established the federal enforceable requirements. This was inserted into the so requirements specific to the Consent decree would not be accidently altered or remove. If there is another underlying applicable requirement that you referenced than we will add it.

- Effective Dates: Note that the permit indicates that the federal register date for the FIP was August 22, 2011, however, the effective date is September 21, 2011, thus the SCR will need to be installed on each of the four units as expeditiously as practicable, but in no event later than 5 years from the effective date of our final rule. The permit should state (see A112B(6)) that compliance with the new emission limit shall not be later than September 20, 2016. In the following comments PNM will use a compliance date of September 21, 2012 date where it appears.

NMED Comment: The FIP requires all construction and all units to comply with the new emission limits by the deadline date of September 20, 2016. I don't understand your compliance date of 9/21/2012. I assume you meant 9/20/2016. NMED has selected a SIP compliance date to be the same as the FIP for this permit action.

The new emission limits and associated monitoring, recordkeeping and reporting do not become effective until the specific dates required for Scenario A (9/20/16) or Scenario B (TBD). Until then, the current permit limits should remain effective. In one case (duct leaks), the M-7 maximum emission rates have been deleted (as these emission sources will be eliminated under either Scenario), but duct leak management program remains in the permit. To help clarify when particular emission standards become effective while others will no longer be required, PNM suggests the following Table be included in the permit:

NMED Comment: This table has been added. Tables in Section A102 are not facility-wide emission limits. Once an option/scenario is picked and installed, then in the next permitting action, the non-selected option will be removed from the permit.

Condition Number	Pollutant	Limit	Condition implementation date begins or requirement end date
Table 106.A	NOx	Current-0.30 lb/MMBtu	Scenario A/B - Ends no later than 9/20/16
Table 106.A	NOx	Scenario A – 0.05 lb/MMBtu	Begins no later than 9/20/16
Table 106.A	NOx	Scenario B – 0.23 lb/MMBtu	Begins no later than 9/20/16
Table 106.A	H2SO4	0.00026 lb/MMBtu10	Begins no later than 9/20/16
Table 106.A	Ammonia Slip	Ammonia Slip wet – Each Scenario A – 2 ppm Scenario B – 10 ppm	Scenario A/B - Begins no later than 9/20/16
Table 106.A	Ammonia Slip	Ammonia Slip (pph) - Each Scenario A – 4.78 units 1-2, 7.31 units 3-4 Scenario B – 23.91 units 1-2; 36.03 units 3-4	Scenario A/B - Begins no later than 9/20/16
Table 106.A	Ammonia Slip	Ammonia Slip - Combined Scenario A – 105.9 tpy Scenario B – 525.0 tpy	Scenario A/B - Begins no later than 9/20/16
Table 106.C	See Table 106.C	See Table 106.C	Scenario A/B - Ends no later than 9/20/16
Table 106.J	See Table 106.J	See Table 106.J	Scenario A/B - Begins no later than

			9/20/16

A footnote should be added to permit Condition A 402C that states that once the balanced draft conversion is complete Condition A 402C will no longer be required. A footnote should also be added to Condition A402 L and Condition A402 M that the conditions do not become effective unless SCR is installed with an effective date of September 20, 2016.

NMED Comment: For Condition A402.C: Adding a footnote is not appropriate here. Within the requirement section of Condition A402.C already states "When each boiler is taken out of service for the purpose of installing the new SCR/SNCR control technologies (balanced draft conversion), this requirement is no longer valid. If the SCR/SNCR technologies are not installed then this requirement remains valid."

For Condition A402.L: The requirement section of the condition was revised but I didn't add the reference to effective date since that would be repetitive. "Only for scenario A as required by the FIP and to demonstrate compliance with the emission limits identified in Table 106.A, the following monitoring is required on a per unit basis."

For Condition A402.M: Ammonia Slip is required by both scenarios, so your suggestion was not used. The requirement section of the condition was revised some, "For both scenario A or B as required by the FIP or SIP and to demonstrate compliance with the emission limits identified in Table 106.A, the following monitoring is required on a per unit basis."

Specific Comments

Page 4, Table 102.A

The total tpy for TSP, PM10 and PM2.5 do not match the permit application. Current values from Tables 2E_A or 2E-B are 1691 tpy TSP (filterable only), 1385 tpy PM10 (filterable only), 2810 PM2.5 (filterable plus condensable). The value given in this table for TSP appears to include condensables, which may be appropriate for fees (per Table 106J), but is not otherwise a regulatory limit. Several of the other values in this table are close to, but do not match exactly, the values given in Tables 2E_A and 2E_B.

Also note that CO should be 39,420 tpy and VOC should be 248 tpy (if rounding to 3 significant digits)

The Table should be revised as follows:

Table 102.A: **Total Potential Criteria Pollutant Emissions from Entire Facility**

Pollutant	**Emissions (tons per year)**
Nitrogen Oxides (NOx) (Pre-construction)	24,703
Nitrogen Oxides (NOx) (Scenario A, SCR)	4,118
Nitrogen Oxides (NOx) (Scenario B, SNCR)	18,941
Carbon Monoxide (CO)	39,420

Pollutant	Emissions (tons per year)
Volatile Organic Compounds (VOC)	248
Sulfur Dioxide (SO_2)	12,352
Total Suspended Particulates (TSP) Filterable	1,691
Particulate Matter less than 10 microns (PM_{10}) Filterable	1,385
Particulate Matter less than 2.5 microns ($PM_{2.5}$) Total	2,810

NMED Comment: Table 102.A values are not emission limits but are total potential emissions. If you are emitting condensables into the atmosphere then they should be included here. TSP wording and values not changed. The NOx for Scenario B, Table 2-E-B is 18, 941 not the 8,941 that you showed.

Page 4, Table 102.B

The Scenario A pound per hour ammonia emission rate is 24.18 (24.2 to 3 significant digits) but pph values are not needed in this table. As noted elsewhere in these comments, in PNM's opinion the permit should be written to be consistent with the FIP which requires that the SCR be designed to achieve a 2ppm ammonia slip rather than specify an ammonia emission limit.

The Scenario B pound per hour ammonia emission rate is 119.8 (120 to 3 significant digits) but pph values are not needed in this table. See above comment. The Table should be revised as follows:

NMED Comment: I have no idea where you get the numbers above. They aren't in any draft of my permit. As stated earlier, 3 significant figures apply to establishing emission limits and not to totals that are not emission limits. In these cases we use values to a tenth of a ton, like 105.9 or 248.0.

Table 102.B: **Total Potential HAPS that exceed 1.0 ton per year**

Pollutant	Emissions (tons per year)
Ammonia (Scenario A, SCR) (NM-TAP)*	106
Ammonia (Scenario B, SNCR) (NM-TAP)*	525
Hydrochloric acid (HCl)	21.3
Hydrofluoric Acid; (Hydrogen fluoride)	44.7
Sulfuric Acid (H2SO4) (Scenario A, SCR Only) (HAP&TAP)	21.6
Total HAPs (Scenario A, SCR Only)	88.2
Total HAPs (Scenario B, SNCR)	66.8
Total HAPs** (Pre-construction)	74.6

*Ammonia emission limits are for inventory purposes only. NMED: this statement of a limit is not appropriate here and is already stated in Condition A106, Emission Limits.

Page 6, Table 103.A

The FIP and SIP applicable requirements are marked as applicable to the entire facility. The specific requirements only affect emissions from the boiler units. They do not establish facility-wide emission limits or conditions. PNM suggests it is more appropriate to mark these as applicable to Units Numbers E310, E302, E303 and E304 rather than to the entire facility. Please revise the Table as follows:

Applicable Requirements	Federally Enforceable	Unit No.
SJGS Federal Implementation Plan (FIP) published in 40 CFR 52.1628 (August 22, 2011)	X	E301, E302, E303, E304
Regional Haze State Implementation Plan (SIP) under 40 CFR 51.309 (June 15, 2012)	X	E301, E302, E303, E304

NMED Comment: This was made as requested.

Page 8, Table 103.C

The last two entries in this table (FIP and SIP requirements) include HCl in the "Description of Requirement". Neither the FIP nor SIP reference HCl and nothing in the proposed modifications under the FIP or SIP are directed at affecting HCl emissions. HCl should be deleted. The FIP does address sulfuric acid, which could be added to the FIP description of requirements. Total HAP for the FIP is affected only in that total HAP includes sulfuric acid. Total HAP should be deleted from the SIP requirement because the SIP adds no new requirements on HAP. Ammonia is a TAP, not a HAP, so even if ammonia limits are adopted for Scenario B, it does not affect total HAP. Also, in the FIP entry, HSO_4 should be H_2SO_4. Please revise the Table as follows:

NMED Comment: This was made as requested.

Emission Unit Nos.	Applicable Requirement	Description of Requirement
E301, E302, E303, E304	FIP (Scenario A)	NOx, Ammonia, H_2SO_4 and HAP Limits
E301, E302, E303, E304	SIP (Scenario B)	NOx, and Ammonia

Page 11, Table 104

Emission units E901 through E904 have both material throughput and baghouse flow rates specified under capacity, whereas, emissions calculations are dependent only on the baghouse flow rate (based on grain loading). Therefore PNM recommends capacity be based on this single value. Please revise the Table as follows:

Unit No. 1	Description	Manufacture	Manufacture Date	Model No.	Serial No.	Capacity	Control Equipment
S901/E901	Activated Carbon Silo	--	Nov 2008	--	--	578 scfm	Dedicated Baghouse (E901)
S902/E902	Activated Carbon Silo	--	Mar 2009	--	--	578 scfm	Dedicated Baghouse (E902)
S903/E903	Activated Carbon Silo	--	Mar 2008	--	--	578 scfm	Dedicated Baghouse (E903)
S904/E904	Activated Carbon Silo	--	Nov 2007	--	--	578 scfm	Dedicated Baghouse (E904)

NMED Comment: This was made as requested.

Page 12 – Table 106.A

The entry that gives the NOx emission limits for Scenario A and Scenario B (as well as the current limit) reference footnote 5 for all cases. However, the 30-day averaging methodology for Scenario A is explicit in the FIP at 40CFR52.1628 d(2) and is not completely consistent with the footnote 5 methodology. PNM recommends a separate footnote for Scenario A NOx emission limits as follows, which is taken from the FIP:

> The NOx limit for each unit in the plant, expressed as nitrogen dioxide (NO_2), shall be 0.05 pounds per million British thermal units (lb/MMBtu) as averaged over a rolling 30 calendar day period. For each unit, NOx emissions for each calendar day shall be determined by summing the hourly emissions measured in pounds of NOx. For each unit, heat input for each calendar day shall be determined by adding together all hourly heat inputs, in millions of BTU. Each day the thirty-day rolling average for a unit shall be determined by adding together the pounds of NOx from that day and the preceding 29 days and dividing the total pounds of NOx by the sum of the heat input during the same 30-day period. The result shall be the 30 day–rolling average in terms of lb/MMBtu emissions of NOx. If a valid NOx pounds per hour or heat input is not available for any hour for a unit, that heat input and NOx pounds per hour shall not be used in the calculation of the 30-day rolling average for NOx. This method of calculating NOx emissions becomes effective on September 20, 2016 if SCR is installed.

The NOx SIP entry indicates the averaging period is a "30 day rolling average" for the FIP. PNM believes that "30 boiler operating day rolling average" is the appropriate description for the SIP averaging methodology.

Note that the entry for the 0.15 lb/MMBtu SO_2 limit references "PNM self imposed, NSR63M6R2" as the applicable requirement and footnote 9 in Table 106A. When the FIP becomes effective in 2016, the FIP will also provide an applicable requirement and the compliance method as given in the FIP will be applicable. Therefore, PNM recommends a similar footnote for SO2 as follows:

> The SO_2 emission rate limit for each unit in the plant shall be 0.15 pounds per million British thermal units (lbs/MMBtu), as averaged over a rolling 30 boiler operating- day period. For each unit on each boiler-operating-day, the hourly SO_2 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 SO_2 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 method of calculating NOx emissions becomes effective on September 20, 2016 if SCR is installed.

Unless SCRs are installed and before the September 20, 2016 effective date, footnotes 5, 6 and 9 remain in effect.

NMED Comment: Changes were made to Note 9 and a new 12 added. You didn't explain why Note 6 would become invalid and I didn't change or add in last comment.

Page 14-15, Table 106.A

PNM recommends the following changes to the entries for H_2SO_4 and ammonia. These changes are consistent with the FIP requirements that the H_2SO_4 limit must be on an "hourly basis" and that a Method 8A test must be conducted "annually. and that the FIP only requires a 2 ppm design and no other emission limit or compliance demonstration is required. If these changes are accepted, footnotes 10 and 11 should be deleted. Please revise the Table as follows:

Unit No.(s)	Pollutant	Maximum Allowable Emission Rate	Averaging Period	Applicable Requirement	Compliance Method
E301 E302 E303 E304	H_2SO_4	0.00026 lb/mmBtu	hourly basis	40 C.F.R. § 52.1628	Annual Method 8A
E301 E302 E303 E304	Ammonia Slip	2 ppm	design basis	40 C.F.R. § 52.1628	SCR design
E301 E302 E303 E304	Ammonia Slip	10 ppm	design basis	40 C.F.R. § 51.309(g)	SNCR design

NMED Comment: Changes were made and shown above and Notes 10 and 11 deleted to speed the issuance of NSR Permit 0063M8.

Page 17, deleted Table 106.C

Duct leak emissions will continue to occur until the balanced draft portion of the modification is completed. The dates for completion of the balanced draft should be the same as that for the other required modifications under Scenario A and B. Thus, it is requested that Table 106C be retained in the permit.

NMED Comment: Table 106.C was added back in the permit with a footnote.

Page 20, Table A106.J

The source of the PM sum value, 3,381 tpy, is unclear. It appears to be the sum of both Scenario A and Scenario B totals. The total PM from the boilers only (at 0.034 lb/mmBtu which is 0.015 filterable plus 0.019 condensable) for Units 1-4 respectively, 552 + 549.2 + 857.5 + 841.2 = 2,799.9 tpy. The non-boiler PM (TSP) is 455 tpy (calculated from Tables 2E, by eliminating the boiler PM) for a total of 3,255 tpy. Please revise the Table as follows:

NMED Comment: Table 106.J was revised as requested.

Unit	[1]NOx	[2]CO	[3]VOC	[4]SO_2	[5]PM
E301	4,871	13,140	48.7	2,435	552
Scenario A	812				244
Scenario B	3,734				244
E302	4,844	8,760	48.5	2,423	549
Scenario A	808				242
Scenario B	3,715				242
E303	7,564	8,760	75.8	3,783	858
Scenario A	1,261				378
Scenario B	5,801				378
E304	7,424	8,760	74.5	3,711	841
Scenario A	1,237				371
Scenario B	5,691				371
Misc					[6]581.1
Scenario A					455
Scenario B					455
Totals*	24,703	39,420	247.5	12,352	3,255
Scenario A	4,118	No Change	No Change	No Change	3,255
Scenario B	18,941	No Change	No Change	No Change	3,255
Used for fees (based on 63M7)	6,000	6,000	247.5	6,000	3,255

Page 21-24, A112 Construction Options

PNM believes that much of the narrative in Section A112 is not appropriate language for permit terms and conditions as the narrative is descriptive rather than specific requirements. This detailed description of equipment and processes would be more appropriate to the Statement of Basis document. PNM suggests these narratives be replaced with a simple list of the equipment that is authorized for construction by this permit as follows:

> This permit authorizes installation of the following:
>
> A. Permitting changes/updates related to Scenario A (FIP) only
>
> 1. An SCR system on each boiler unit
> 2. An anhydrous ammonia injection system used for supplying ammonia to the SCR system consisting of ammonia delivery, storage and injection equipment.
> 3. A dry sorbent injection system (DSI) consisting of DSI delivery, storage and injection equipment.
> 4. Modification of the fly ash handling system through addition of ash hoppers at the economizer outlets on each boiler unit and bypass of the existing ESP structure.
> 5. Modification of the fan system to achieve "balanced" draft configuration allowing for the elimination of emission points E510, E502, E503 and E504.
>
> B. Permitting changes/updates related to Scenario B (SIP) only
>
> 1. A system for delivery, storage and injection of 50 percent urea solution into the flue gas of each boiler for NOx control by SNCR.
> 2. Modification of the fan system to achieve "balanced" draft configuration allowing for the elimination of emission points E510, E502, E503 and E504.

NMED Comment: Your suggested revisions were made and information added to Statement of Basis.

Page 24, A114

Remove the instructions in brackets; insert the language " in accordance with the implementation scheduled in the FIP or SIP" at the end of paragraph A in place of "insert the .... of this permit." Please revise the condition as follows:

A. Certain terms and conditions of this permit reduce the potential emission rate of regulated equipment to values below those allowed prior to the date of issuance of this permit. The compliance date for construction or operation of the emission units and pollution control equipment required to achieve this reduction in potential emission rate is in accordance with the implementation scheduled in the FIP (September 20, 2016) or SIP (September 20, 2016).

NMED Comment: Your suggested revision was made. NMED as established the SIP deadline the same as FIP.

Page 32, A402.L

PNM appreciates NMED efforts in developing a reasonable method of compliance for the FIP Sulfuric Acid emission limit of 0.00026 lb/mmBtu, however, PNM is concerned that the FIP requires an annual Method 8A compliance test and that EPA may reject the SCR/SNCR permit unless it requires the annual H2SO4 stack test. PNM, therefore, suggests the following alternative monitoring requirement that recognizes the H2SO4 limit is far below the Method 8A limit of detection:

> **Monitoring:**
>
> The current Method 8A test, as specified in the FIP, does not have the sensitivity to measure accurately to 0.00026 lb/mmBtu levels. As a result, each unit shall be considered in compliance with the sulfuric acid emission limit if the results of the Method 8A test are at or below the level representing three times the representative detection limit (RDL) of Method 8A, which is 0.0018 lb/mmBtu (equal to three times the RDL of 0.0006 lb/mmBtu). This method of demonstrating compliance is consistent with EPA's approach in addressing measurement imprecision and variability for electric generating units, like those at SJGS, and for other industries as well. 77 Fed. Reg. 9304, 9390 (Feb. 16, 2012) (describing a 3xRDL approach). Once every three years from the issuance of this permit, PNM shall conduct a survey of test methods approved by EPA to determine if new test methods are available that can accurately measure 0.00026 lb/mmBtu with a measurement imprecision of less than 20%. Once a new, more accurate test method becomes available, PNM shall perform the test once every calendar year on each unit to demonstrate compliance with the emission limit of 0.00026 lb/mmBtu.

Note, CTM-013 (i.e., Method 8A) indicates that "the minimum detectable limit (MDL) of the method is 0.50 milligrams/cubic meter," which translates to 0.0006 lb/mmBtu for SJGS.

NMED Comment: Your suggested revision was made to the monitoring and we made sight revision to recordkeeping and reporting.

Page 33 – A402.M

The requirements for ammonia slip monitoring, reporting and recordkeeping exceed those required in the FIP. The FIP preamble states:

After careful consideration of the comments we received concerning our proposal to require the SJGS to meet an hourly average emission limit of 2.0 parts ppmvd for ammonia, we have determined that neither an ammonia limit, nor ammonia monitoring is appropriate. Instead, we will approach the issue of the impact of ammonia slip on visibility impairment though proper *upfront design, rather than after-the-fact regulation. We are requiring that the NOx control device (presumably, but not required to be SCR) must be designed to achieve a NOx emission limit of 0.05 lbs/MMBtu on a rolling 30 BOD basis with an ammonia slip of 2.0 ppm. We believe this strikes the proper balance between the additional cost of ammonia monitoring and reporting and the need to have a reasonable expectation of the amount of ammonia emitted by the SJGS.*

In keeping with the FIP approach to ammonia slip, PNM requests that compliance with ammonia slip (for either Scenario A or Scenario B) be based on the design of the ammonia injection system (as evidenced by vendor design specifications, engineering drawings and/or equipment operation manuals) and a requirement that for Scenario A the ammonia injection system catalyst replacement schedule be performed per equipment vendor specifications. PNM would also agree to an initial ammonia emissions stack test to confirm each Unit is achieving less than or equal to 2 ppm ammonia slip. PNM recommends the following wording for the "Requirement" Section:

> **Requirement:**
>
> To demonstrate compliance with the emission limits identified in Table 106.A, PNM must confirm as part of its initial compliance demonstration following the construction of the additional control equipment authorized by this permit that the controls are designed to meet the applicable ammonia slip limits (2 ppm for SCR under Scenario A, and 10 ppm for SNCR under Scenario B). Since no further emission limits apply, no additional monitoring is required.

NMED Comment: Your suggested revision was made.

Page 33-34, A403.B

PNM requests a waiver from the requirement to perform quarterly opacity observations for the emergency generators. These engines operate less than 500 hours per year and only during emergencies. PNM has conducted quarterly observations on these engines since the first quarter 2011 and all observations indicate opacity is consistently below (usually far below) 20 percent.

NMED Comment: Condition A403.B was deleted because the units are emergency generators exempt in accordance with 20.2.72.202.B(3) NMAC and the opacity requirement is not necessary for these engines at this time. PNM requested these units be listed in the permit versus just being identified as exempt and not being listed in the permit.

Page 34, Table 405.A

Note that E410 and E411 have been combined into E410. PNM prefers that the TDS be expressed in terms of mg/l as these are the measurement units used in normal laboratory water testing procedures. If the Department requires the TDS be expressed in terms of lbs/gallon the appropriate values are:

6,000 mg/l * 1 gram/1,000 mg * 1 lb/453.59 grams * 1 liter/0.264179 gallons = 0.0501 lbs/gallon for E406, E407 and E409, and;

3,900 mg/l * 1 gram/1,000 mg * 1 lb/453.59 grams * 1 liter/0.264179 gallons = 0.0325 lbs/gallon for units E408 and E410.

Please update the Table as follows:

Emission Unit No.	Circulating Water Rate (gpm)	TDS Content (milligrams/liter)	Drift Rate (percent)
E406	170,000	6,000	0.002
E407	165,000	6,000	0.002
E408	220,000	3,900	0.00015
E409	227,500	6,000	0.002
E410	35,000	3,900	0.002

NMED Comment: Your suggested revision was made except for the assume typo 0.00015 vs 0.0015 currently in permit.

Page 40, B105.A

PNM requests the words "or as directed by the Department" be added to the end of this condition. This additional wording is already included in the SJGS Title V permit.

NMED Comment: Your suggested revision was made.