TECHNICAL SUPPORT DOCUMENT

AND STATEMENT OF BASIS

FOR MODIFICATION TO

TUCSON ELECTRIC POWER COMPANY
Springerville Generating Station

December 21, 2001

Permit No. 1001554

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TECHNICAL REVIEW AND EVALUATION OF
OF APPLICATION FOR AIR QUALITY TITLE V PERMIT NO. 1001554
(SIGNIFICANT REVISION TO PERMIT NO. 1000105)

Tucson Electric Power Company- Springerville Generation Station

I. INTRODUCTION

The proposed Class I / Title V permit No. 1001554 is for a proposed major modification to the Tucson Electric Power Company(TEP) - Springerville Generating Station (SGS), located in Apache County, approximately 10 miles north of Springerville, Arizona. The proposed permit is a significant revision to the Class I / Title V permit No. 1000105. TEP-SGS is a coal fired electric generating facility. It presently consists of two coal-fired units and associated support services. The proposed modification will add two new coal-fired units.

A. Company Information

Facility Name:	Tucson Electric Power Company Springerville Generation Station
Mailing Address:	220 West Sixth Street, P.O. Box 711 Tucson, AZ 85702-0711-01
Facility Location:	10 miles north of Springerville on Highway 666; 12 miles east on site access Road, Springerville, Apache County, AZ

B. Attainment Classification (Source: 40 CFR §81.303)

The air quality control region in which the subject facility is located either is unclassified or is classified as being in attainment of the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants: particulate matter less than 10 microns (PM-10), nitrogen dioxide (NO_2), sulfur oxides (SO_x), carbon monoxide (CO), lead (Pb) and ozone (O_3).

II. PROCESS DESCRIPTION

A. Existing Facility

TEP - SGS is a steam electric generating station operating under Standard Industrial Code (SIC) 4911. The facility is operated 24 hours a day and 365 days a year. The existing facility consists of two steam generating units, each fired primarily with coal; associated fuel and ash handling systems, and ancillary equipment.

Coal is delivered to the site by train. Coal is unloaded by means of rotary car dumper at a rate of approximately 3000 tons per hour. Coal is transferred for storage via the covered conveyor belts. Dust collection and suppression systems are utilized at coal transfer points.

The existing facility also has an auxiliary boiler, which is used for cold start-up for the two steam generating units, and two mechanical induced draft cooling towers, which are used to remove heat from the main condenser circulating water systems.

The existing ash disposal system handles fly ash from both of the existing steam generating units. Fly ash from the filter baghouses is transferred via a pneumatic system to the fly ash silos. Bottom ash is removed from the boilers and transferred by conveyor pipes to dewatering bins. Both fly ash and bottom ash are hauled to the ash burial area located on site.

Each of the two existing steam generating units is equipped with a filter baghouse for particulate collection. Spray Dry Absorbers(SDA) are used to control SO_2. Low NOx burners, overfire air ports and good operating practices control NOx emissions.

B. Proposed Major Modification

Tucson Electric Power proposes to install and operate a two unit pulverized coal-fired (PC) expansion to the existing facility near Springerville, AZ which will be capable of generating 400 net megawatts (MW) of power from each PC boiler-based generating plant.

The proposed major modification will not involve any modification to the existing Unit 1 or Unit 2, but measures may be implemented in order to reduce emissions from Unit 1 and Unit 2 in order to maintain the net emissions increase below the Prevention of Significant Deterioration (PSD) significant level.

Major equipment for each unit will consist of a pulverized coal boiler, an extraction-condensing turbine electrical power generator, air pollution control equipment, a water-cooled surface steam condenser, boiler feedwater systems including condensate and feedwater pumps, feedwater heaters and a deaerator. There will be a circulating water system to provide cooling water to the steam condenser, including circulating water pumps, a mechanically-induced draft cooling tower, a water supply pipeline, and a water

storage pond. The facility will include coal unloading and storage facilities, ash handling equipment, lime handling, water treatment facilities, as well as plant support equipment including HVAC, fire protection, plant air, potable water and sanitary sewer lines.

The main boiler heat input at full load is estimated at 4200 MMBTU/hr. Oil firing will be for startup and flame stabilization only. Coal and oil burner configurations and combustion control systems will be designed to provide high combustion efficiency and to control production of NO_X in the flue gas.

The boiler area will be a totally enclosed design. Burners will be located on the front and rear furnace walls or in the four (4) corners of the furnace walls. The coal silos will be located along the boiler front, with an enclosed coal tripper gallery. The principal components of each boiler will be a membrane wall furnace, superheater, reheater, economizer, convection pass, pulverizers, low NO_X burners, fans, and air heater, flues and ducts, piping and valves.

The nitrogen oxides removal will be with a Selective Catalytic Reduction (SCR) system. Ammonia will be injected into the flue gas upstream of a catalyst bed. The catalyst promotes a reduction reaction involving the nitrogen oxides and ammonia, resulting in water and elemental nitrogen in the flue gas exiting the catalyst bed.

The sulfur dioxide removal will be with a Flue Gas Desulfurization (FGD) cleanup system. The FGD cleanup system for the PC boiler will consist of spray dryer absorbers (SDAs) for desulfurization and acid gas control, and a baghouse for particulate matter (including trace metals) control.

Flue gas from the air heater will enter the SDAs, where it will be humidified and cooled by spraying with lime slurry. Simultaneously, the flue gas will provide drying energy to the atomized slurry. The cooled gas, along with the entrained reaction products and fly ash, will flow to the fabric filter where solids will be separated from the gas.

The system will use lime slurry (calcium hydroxide) as the absorbing medium. Pebble lime will be slaked in the lime preparation system, diluted and stored in the lime feed tanks. Lime slurry will be pumped from the feed tank to the agitating atomizer head tank, from which the slurry will be pumped to the absorbers.

Lime will be delivered to the site by rail with back-up delivery by truck and stored in a totally enclosed structure.

Flue gas from the FGD system will enter the baghouse through an inlet manifold, which will distribute the flue gas into the bag filter compartments. Flue gas will pass through the fabric filter of the bags. Collected particulate will be retained as filter cake on the surface of the bags. An automatic pulse-cleaning cycle releases the collected fly ash from the bags to the collection hoppers. A pneumatic transfer system will transport the

particulate ash from the hoppers to the ash storage silo, in preparation for final disposal. Fly ash will be wet conditioned for dust control for disposal.

The clean flue gas will go from the baghouse exit through the induced-draft fans and will be exhausted through an exhaust stack to the atmosphere. The stack will consist of a concrete wind shell and two flues, one per boiler. A continuous emission monitoring system will be provided to monitor emissions from each flue.

The proposed primary fuel will be a sub-bituminous coal. Coal will be delivered to the plant in open rail cars and unloaded into an unloading hopper inside a coal unloading building. The coal will be transported to storage area and then to the plant by means of a covered conveyor.

No. 2 oil will be used for light-off, start-up and flame stabilization. Fuel oil is stored in an existing above-ground tank located on the plant site.

III. EMISSIONS

The following tables summarize the emissions from the proposed new and modified equipment at the TEP-SGS facility.

IV. APPLICABLE REGULATIONS

A. Applicable Regulations Verification

The Permittee has identified all applicable regulations that apply to each unit identified in the permit application. Table IV.1 summarizes the findings of the Department with respect to the applicability or non-applicability of these regulations.

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
State of Arizona Requirements (Arizona Administrative Code [AAC], Title 18, Chapter 2)					
R18-2, Article 1	Definitions and general information regarding AAC Title 18, Chapter 2.				
R18-2, Article 2	Identification of ambient air quality standards for criteria pollutants, designation and classification of attainment areas and limits for Pollutants in classified attainment areas.				This requirement does not apply to permittees except to identify nearby areas for PSD evaluation.
R18-2-Article 3	Permits and Permit Revisions				
R18-2-301	Definitions for Article 3, Permits and Permit Revisions				This is not an applicable standard or limitation, however, these definitions do apply when evaluating other applicable requirements within Article 3
R18-2-302	Obtain a Class I Permit Revision from ADEQ prior to commencing construction of Units 3 and 4				
R18-2-303	Requirements for transitioning from Installation and Operating Permit Program to Unitary Permit Program				Since Units 3 and 4 do not have the old style installation permits, this does not apply.
R18-2-304	The permit revision application must meet the requirements specified in order to be considered complete.				
R18-2-305	A notice of confidentiality (requesting that portions of the permit application be kept confidential) must comply with requirements specified in R18-2-305(B).				
R18-2-306	Requirements for contents of permit				ADEQ is responsible for issuing a permit complying with R18-2-306(A),(B),(C),(D), and (E).

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
R18-2-306.01	Voluntarily Accepted Limitations				Requesting plant-wide SO2 and NO_X emission caps only, pursuant to R18-2-306.02
R18-2-306.02	Emission Caps				SO2 and NO_X plant-wide, annual emission caps (see Section 8.0 of application)
R18-2-307	Provide the EPA and affected states with a copy of the permit revision application.				
R18-2-308	All applicable requirements shall be included in the issued permit revision.				This is an obligation of the issuer of the permit (ADEQ).
R18-2-309	Elements of the compliance plan required to be included in the issued permit revision.				Although this is an ADEQ obligation, a compliance plan detailing compliance strategies should be included in the permit revision application.
R18-2-310	During occurrences of emissions from the units in excess of an applicable emission limitation, the facility must comply with the reporting and recordkeeping requirements presented.				
R18-2-311	This regulation specifies the applicable procedures and testing methods that can be used to determine compliance with applicable requirements.				
R18-2-312	Within 60 days (but no later than 180 days) after Units 3 and 4 have achieved maximum production, performance tests must be conducted. Performance tests must comply with the requirements in R18-2-312.				
R18-2-313	Monitoring requirements for existing sources.				Units 3 and 4 are new sources.

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
R18-2-314	A Quality Assurance Plan consistent with R18-2-311(D)(3) is required for all permitted sources.				The existing quality assurance plan shall be revised to include monitoring and/or testing associated with Units 3 and 4.
R18-2-315	Post revised permit and mark Units 3 and 4 with a serial number or other equipment number also listed in the permit.				
R18-2-316	Notice by Building Permit Agencies				This requirement is not an obligation of permit applicant.
R18-2-317	Facility Changes Allowed Without Permit Revisions - Class I				Installation of Units 3 and 4 requires a significant permit revision.
R18-2-317.01	Facility Changes that Require a Permit Revision – Class II				Applies to Class II sources only. SGS is a Class I source.
R18-2-317.02	Procedures for Certain Changes that do not Require a Permit Revision – Class II				Applies to Class II sources only. SGS is a Class I source.
R18-318	List of items qualifying as administrative permit revisions				Installation of Units 3 and 4 requires a significant permit revision.
R18-318.01	Annual Summary Permit Amendments for Class II Permits				Applies to Class II sources only. SGS is a Class I source.

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
R18-319	Changes at Class I or Class II sources for which a minor permit revision may be used.				Installation of Units 3 and 4 requires a significant permit revision.
R18-2-320	Requirements for significant permit revisions.				Pursuant to R18-2-320(A), proposed Units 3 and 4 do not satisfy the minor revision requirements of R18-2-319(A) (3, 4, 5 and 7)
R18-2-321	Permit Reopenings; Revocation and Reissuance; Termination				This is not a reopening, etc.
R18-2-322	Permit Renewal and Expiration				This is not a renewal
R18-2-323	Transferring of permit to another person				Permit is not being transferred
R18-2-324	Permitting of Portable Sources				Units 3 and 4 are not portable sources
R18-2-325	Permit Shields – the permit will identify all applicable requirements				
R18-2-326	Appropriate fees associated with the significant permit revision as specified in this section must be submitted to ADEQ.				Pursuant to R18-2-326(I), application fee for Significant revisions is $10,000. Pursuant to 326(N) fee is increased to $15,000 for accelerated processing. Technical review of application reduced to 120 days.
R18-2-327	Emissions from the two new units must be included in the annual emission inventory.				
R18-2-328	Requirements for conditional orders issued by ADEQ.				Conditional Order not requested.

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
R18-2-329	Requirements for Permits Containing the Terms and Conditions of DCOs or Consent Decrees				No applicable DCOs or Consent Decrees
R18-2-330	Requirements for public participation on permits.				
R18-2-331	Description of material permit conditions				
R18-2-332	Requirements and limitations of stack height.				
R18-2-333	Incorporation by reference of federal Acid Rain requirements presented in 40 CFR 72, 74, 75, and 76				See the federal requirements section of this table for additional detail
R18, Article 4	Permit Requirements For New Major Sources And Major Modifications To Existing Major Sources (See details below)				
R18-2-401	Definitions For Article 4, Permit Requirements For New Major Sources And Major Modifications To Existing Major Sources				This is not a standard or limitation, however, these definitions do apply when evaluating other applicable requirements from Article 4.
R18-2-402	General permitting requirements for new major sources or a major modification of a source.				Units 3 and 4 will be major modificartions of an existing major source.
R18-2-403	Permits for Sources Located in Non-attainment Areas				The facility is located in an attainment area.
R18-2-404	Standards for emission offsets and Net Air Quality Benefit Standards				No emission offsets are being used in the permit revision.
R18-2-405	Special Rule for Major Sources of VOC or Oxides of Nitrogen in Ozone Non-attainment Areas Classified as Serious or Severe				The facility is located in an attainment area.

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
R18-2-406	Permitting requirements for major modifications to major sources located in attainment areas including requirements for the application of BACT, air impact analyses and monitoring, and modeling.				Applies to CO, PM10 and Pb only.
R18-2-407	Air quality impact analysis and monitoring associated with R18-2-406 must be in accordance with these requirements.				Monitoring requirements for CO, PM10 and Pb will apply.
R18-2-408	Allows use of innovative control technologies in place of BACT for a new major source or major modification.				No innovative technologies are being used
R18-2-409	Air quality modeling required in association with any major permit modification must be conducted in accordance with the guidelines of R18-2-406(A)(6((a).				
R18-2-410	Requires an analysis of the anticipated impacts of the proposed source on visibility in any Class I areas near the source. Additionally, the analysis must be conducted in accordance with the requirements of this section.				
R18-2-411	Special Rule for Non-operating Sources of Sulfur Dioxide in Sulfur Dioxide non-attainment Areas				The SGS facility is not located in an SO_2 non-attainment area.
R18-2, Article 5	Requirements for general permits issued by ADEQ				A general permit is not available for Units 3 and 4.
R18-2, Article 6	Emissions From Existing And New Nonpoint Sources (See details below)				

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
R18-2-601	Definition of a nonpoint source as R18-2, Article 6 applies				This is not an applicable standard or limitation, however, this definition must be used to determine which sources are subject to Article 6.
R18-2-602	Identifies operations that are unlawful open burning.				No open burning is planned in association with Units 3 and 4.
R18-2-604	Reasonable precautions must be taken to prevent excessive fugitive emissions of particulate matter in open areas. This includes earth moving activities during construction.				This applies during and after construction of Units 3 and 4.
R18-2-605	Reasonable precautions must be taken to prevent excessive fugitive emissions of particulate matter on roadways and streets.				This includes traffic on roadways and streets associated with the transfer of coal and ash for Units 3 and 4.
R18-2-606	Reasonable precautions must be taken to prevent excessive fugitive emissions of particulate matter from material handling activities.				Coal and ash handling activities associated with Units 3 and 4 must comply with this requirement.
R18-2-607	Reasonable precautions must be taken to prevent excessive fugitive emissions of particulate matter from storage piles or activities associated with storage piles.				Coal storage piles must comply with this requirement.
R18-2-608	Preventing excessive particulate emissions from Mineral Tailings				Applies to mineral tailings only (e.g., hard rock ore milling operations).
R18-2-609	Preventing excessive particulate emissions from agricultural practices.				Applies to agricultural practices only.

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
R18-2-610	Definitions applying to R18-2-611.				Not a standard or limitation. Applies to agricultural practices in Maricopa County only.
R18-2-611	Requirement for Agricultural PM10 permit.				Applies to agricultural practices in Maricopa County only (SGS is in Apache County).
R18-2-612	Opacity of an emission from any nonpoint source (coal handling, ash handling etc.) shall not be greater than 40%.				
R18-2, Article 7	Performance standards for existing stationary sources.				Units 3 and 4 are subject to the performance standards for new stationary sources identified in R18-2, Article 9; therefore are exempt from Article 7.
R18-2, Article 8	Emissions From Mobile Sources (New And Existing)				Units 3 and 4 are stationary sources.
R18-2, Article 9	Performance Standards for New Stationary Sources (specific requirements are discussed below)				
R18-2-901(1)	Incorporates by reference Subpart A of 40 CFR 60, General Provisions for NSPS				This requirement is a federal requirement incorporated by reference and is discussed in the federal requirement portion of this table.
R18-2-901(2)	Incorporates by reference Subpart D of 40 CFR 60, Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971.				This requirement does not apply as Subpart Da is applicable to Units 3 and 4 (installed after September 18, 1978)

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
R18-2-901(3)	Incorporates by reference Subpart Da of 40 CFR 60, Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978.				This requirement is a federal requirement incorporated by reference and is discussed in the federal requirement portion of this table.
R18-2, Article 10	Requirements for inspections and maintenance of motor vehicles.				
R18-2, Article 11	National Emission Standards for Hazardous Air Pollutants				
R18-2, Article 14	Conformity Determinations				
Federal Requirements					
40 CFR 60, Subpart A, General Provisions for Standards of Performance for New Sources					
40 CFR 60.1	Specifies applicability of 40 CFR 60 to specified sources.				This section does not have specific applicable requirements, but presents the applicability of the rule.
40 CFR 60.2	Definitions for 40 CFR 60 and associated Subparts.				This is not an applicable standard or limitation, however, these definitions do apply when evaluating other applicable requirements within 40 CFR 60 and its subparts.
40 CFR 60.3	Units and Abbreviations for 40 CFR 60 and associated Subparts				This section does not have specific applicable requirements, but presents the units and abbreviations used in 40 CFR Part 60 and its subparts.
40 CFR 60.4	Specifies addresses for communication regarding NSPS standards with regional administrators				This section does not have specific applicable requirements.

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
40 CFR 60.5	Administrator determination of construction or modification.				It has been determined that the installation of Units 3 and 4 constitutes a modification.
40 CFR 60.6	Requesting review of plans by the Administrator for technical assistance on NSPS				Review by the Administrator for technical assistance has not been requested.
40 CFR 60.7	Notification, reporting and recordkeeping requirements for the affected units and the continuous emissions monitoring systems (CEMS)				Applies to initial startup, initial performance tests, CEMS certification testing, etc.
40 CFR 60.8	Conduct performance tests when requested by agency (or as required by permit)				
40 CFR 60.9	Availability of information to the public regarding this source and permit				
40 CFR 60.10	State Authority				
40 CFR 60.11	Performance test methods, applicability of opacity standard, and operation of the facility, to the extent practicable, in a manner consistent with good air pollution control practice for minimizing emissions				
40 CFR 60.12	Sources should not be constructed in a manner that conceals emission so as not to be subject to 40 CFR 60.				Units 3 and 4 are subject to 40 CFR 60.

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
40 CFR 60.13	Continuous monitoring systems used for Units 3 and 4 are subject to the provisions stated in this section.				
40 CFR 60.14	Describes changes at a facility that qualify as a modification in accordance with 40 CFR 60.				It had been determined that the installation of Units 3 and 4 constitutes a modification.
40 CFR 60.14(e)(5)	Exemption (from definition of "Modification") for improved control systems				Pertains to physical changes planned for Units 1 and 2 to lower SO2 and NOx emissions.
40 CFR 60.15	Description of reconstruction at a facility.				Existing SGS is not being "reconstructed", as defined in the rule.
40 CFR 60.16	Priority List				No specific requirements are presented in this section.
40 CFR 60.17	Incorporations by reference				No specific requirements are presented in this section.
40 CFR 60.18	Requirements for specific types of control devices.				The control devices used for Units 3 and 4 are not covered by this section.
40 CFR 60.19	General notification and reporting requirements				
40 CFR 60, Subpart Da, Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978					

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
40 CFR 60.40a	Description of unit to which Subpart Da applies				Units 3 and 4 are subject to Subpart Da.
40 CFR 60.41a	Definitions for 40 CFR 60, Subpart Da				This is not an applicable standard or limitation, however, these definitions do apply when evaluating other applicable requirements from Subpart Da
40 CFR 60.42a	Standards for discharge of particulate for sources subject to 40 CFR 60, Subpart Da. Particulate matter may not exceed 0.03 lb/MMBtu heat input from all fuels and) 1 percent of the potential combustion concentration (99 percent reduction). Opacity may not exceed 20%, except for one six-minute period per hour of not more than 27% opacity.				
40 CFR 60.43a	Standards for discharge of sulfur dioxide for sources subject to 40 CFR 60, Subpart Da. Sulfur dioxide emissions may not exceed 1.2 lb/MMBtu heat input and 10 percent of the potential combustion concentration or 30 percent of the potential combustion concentration when emissions are less than 0.60 lb/million Btu heat input as specified in 40 CFR 60.43a (1).				

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
40 CFR 60.44a	Standards for discharge of nitrogen oxides for sources subject to 40 CFR 60, Subpart Da. NO_X emissions may not exceed 1.6 pounds per megawatt hour gross energy output, 30 day rolling average as specified in 40 CFR 40 CFR 60.44a(d)				
40 CFR 60.45a	Commercial Demonstration Permit				
40 CFR 60.46a	Requirements for maintaining compliance with emission limitations in 40 CFR 60 42a, 43a, and 44a.				
40 CFR 60.47a	Requirements for emission monitoring for sources subject to Subpart Da				
40 CFR 60.48a	The compliance determination procedures and methods must be used for sources subject to Subpart Da				
40 CFR 60.49a	Sources subject to Subpart Da must comply with the reporting requirements in this section				
40 CFR 60, Subpart Y, Standards of Performance for Coal Preparation Plants					
40 CFR 60.250	Identifies sources to which Subpart Y is applicable				

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
40 CFR 60.251	Definitions for 40 CFR 60, Subpart Y.				This is not an applicable standard or limitation, however, these definitions do apply when evaluating other applicable requirements from Subpart Y.
40 CFR 60.252	Standards for discharge of particulate matter from sources subject to Subpart Y. Opacity from coal handling operations must be less than or equal to 20%				
40 CFR 60.253	Monitoring requirements for thermal dryers				Thermal dryers are not used for Units 3 and 4.
40 CFR 60.254	Any monitoring and/or testing required by Subpart Y (e.g., opacity testing), must be conducted in accordance with this section.				
40 C.F.R. § 64	Compliance Assurance Monitoring				SGS is subject to federal acid rain program and is thus exempt from Part 64, pursuant to 40 CFR 64.2(b)(1)(iii). A CAM plan will be required for particulate.
40 C.F.R. § 68	Risk Management Program				
40 C.F.R. § 70	Operating Permit Program				The plant will become affected by this requirement one year after Units 3 and 4 are placed into commercial operation.

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
40 CFR 72 Permits Regulation					
40 CFR 72 Subpart A	General Provisions of the Acid Rain Program. 40 CFR 72.9 specifies the standard permitting, monitoring, sulfur dioxide, NO_X, excess emissions, recordkeeping and reporting, and liability requirements for affected sources.				The requirements of 40 CFR 72.9 applies to Units 3 and 4.
40 CFR 72 Subpart B	Designated Representative. Specifies the requirements for and responsibilities of the responsible official for the sources subject to Subpart A.				
40 CFR 72 Subpart C	Requirements for Acid Rain Permit Applications including the following requirements				An application for an Acid Rain permit must be filed for Units 3 and 4 in accordance with the requirements of this subpart.
40 CFR 72 Subpart D	Acid Rain Compliance Plan and Compliance Options				This subpart pertains primarily to Phase I sources. SGS Units 3 and 4 will be Phase II sources.
40 CFR 72 Subpart E	Acid Rain Permit Contents				This is technically an ADEQ obligation
40 CFR 72 Subpart F	Federal Acid Rain Permit Issuance Procedures				This is technically an ADEQ obligation
40 CFR 72 Subpart G	Acid Rain Phase II Implementation				

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
40 CFR 72 Subpart H	Requirements for permit revisions				A new application is submitted for Units 3 and 4, so no permit revision is being obtained.
40 CFR 72 Subpart I	Requirements for Compliance Certification of affected units and annual compliance report				The compliance certification and annual report for Units 3 and 4 must meet the requirements of this section.
40 CFR 73, Sulfur Dioxide Allowance System					
40 C.F.R. Part 73	Sulfur dioxide allowance system				The plant must have sufficient allowances available to account for each ton of annual SO_2 emissions.
40 CFR 75 Continuous Emission Monitoring					
40 CFR 75 Subpart A	General Provisions of the Continuous Emission Monitoring requirements of the Acid Rain Program. 40 CFR 75.3 specifies compliance dates.				Units 3 and 4 must comply with the compliance dates specified in 40 CFR 75.3
40 CFR 75 Subpart B	Provisions for monitoring under 40 CFR 75. Specifies general operating requirements, specific provisions for monitoring of SO2, NO_X, and CO2.				The CEMs associated with Units 3 and 4 must comply with this subpart.
40 CFR 75 Subpart C	Requirements for operation and maintenance of continuous emission monitors.				The CEMs associated with Units 3 and 4 must comply with this subpart.

Table IV.1 - Regulatory Applicability					
Applicable Requirement	**Summary of Requirement**	**Applicable to TEP - SGS Modification?**			**Comments**
		Yes	**No**	**N/A**	
40 CFR 75 Subpart D	Specifies procedures for periods where CEM data is missing.				In the event of missing data for Units 3 and 4, the procedures in this subpart must be followed.
40 CFR 75 Subpart E	Requirements for alternative monitoring systems.				Alternative monitoring systems are not being used for Units 3 and 4.
40 CFR 75 Subpart F	Specifies requirements for recordkeeping associated with CEMs				All recordkeeping from the CEMs associated with Units 3 and 4 must meet the requirements specified in this subpart.
40 CFR 75 Subpart G	Specifies requirements for reporting associated with CEMs				All reporting from the CEMs associated with Units 3 and 4 must meet the requirements specified in this subpart.
40 CFR 75 Subpart H	NO_X Mass Emissions Provisions				Mass Emissions Reduction requirements currently not applicable, thus monitoring provisions not applicable
40 C.F.R. Part 76	This part of the Acid Rain Regulations specifies requirements for NO_X Reduction.				Units 3 and 4 must comply with 40 CFR 76
40 C.F.R. Part 77	This part of the Acid Rain Regulations specifies the requirements for addressing excess emissions of SO_2 (exceeding allowances)				These requirements would only become applicable in the event of an exceedance of available allowances.

B. PSD Netting Analysis

1. Introduction

The Prevention of Significant Deterioration (PSD) regulations under Title I of the Federal Clean Air Act and R18-2-406.A are applicable to construction of a major modification. At an existing major stationary source such as the TEP - SGS facility, a major modification is a physical change or change in the method of operation that results in a net emissions increase that is significant.

The proposed Units 3 and 4 will have the potential to emit in excess of the PSD "significant" levels for eight pollutants: PM, PM-10, SO_2, NO_X, CO, VOC, fluorides, and sulfuric acid mist. (See Section III herein for a detailed discussion of emission calculations and potential to emit for the proposed expansion project.) As noted in Section IV.A herein, the PSD regulations are applicable for PM, PM-10, CO, VOC, and fluorides. For SO_2, NO_X, and sulfuric acid mist, the Permittee has proposed to accept voluntary emission limitations that will maintain the net emissions increase below the corresponding significant levels.

The proposed voluntary emission limitations are "emission caps" over Units 1, 2, 3, and 4. The emission caps for SO_2, NO_X, and sulfuric acid mist are set at levels equal to the actual emissions of those pollutants from Units 1 and 2 during calendar years 1999 and 2000. The emission caps will limit the potential to emit, and thus the actual emissions, of the four boilers to levels that are no greater than past actual emissions. In order to comply with the proposed emission caps, the Permittee will be required to reduce emissions from the existing Units 1 and 2 for SO_2, NO_X, and sulfuric acid mist in amounts that correspond to the actual emissions from Units 3 and 4.

2. PSD Regulatory Discussion

The term "net emissions increase" is defined at A.A.C. R18-2-101.72 as:

"a. The amount by which the sum of subsections (i) and (ii) exceeds zero:
   i. Any increase in actual emissions from a particular physical change or change in the method of operation at a stationary source; and
   ii. Any other increases and decreases in actual emissions at the source that are contemporaneous with the particular change and are otherwise creditable.

"b. An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between:
   i. The date 5 years before construction on the particular change commences; and
   ii. The date that the increase from the particular change occurs.

"c. An increase or decrease in actual emissions is creditable only if the Director has not relied on it in issuing a permit, which is in effect when the increase in actual

emissions from the particular change occurs. In addition, in nonattainment areas, a decrease in actual emissions shall be considered in determining net emissions increase due to modifications only if the state has not relied on it in demonstrating attainment or reasonable further progress.

"d. An increase or decrease in actual emissions of sulfur dioxide, nitrogen oxides, or PM-10 which occurs before the applicable baseline date, as described in R18-2-218, is creditable only if it is required to be considered in calculating the amount of maximum allowable increases remaining available.

"e. An increase in actual emissions is creditable only to the extent that the new level of actual emissions exceeds the old level.

"f. A decrease in actual emissions is creditable only to the extent that:

i. The old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of actual emissions;

ii. It is federally enforceable at and after the time that actual construction on the particular change begins;

iii. It has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change; and

iv. The emissions unit was actually operated and emitted the specific pollutant."

The U.S. EPA's definitive guidance for determining the "net emissions increase"is set forth in Chapter B of the October 1990 New Source Review Workshop Manual.[1] The Department used the above definition, in conjunction with the guidance set forth in the NSR Workshop Manual, in determining the net emissions increases of SO_2, NO_X, and sulfuric acid mist from the proposed expansion of the TEP - SGS facility. This determination is discussed in the following paragraphs:

Project Increase

The first step in the net emissions increase determination, under paragraph 72.a.i, is to quantify the emissions increase that would result from the particular physical change itself, without considering any other changes. In this instance, the particular physical change is the installation of the new boilers, which is greater than significant for eight PSD-regulated pollutants as noted above. Thus, under paragraph 72.a.ii, other contemporaneous and creditable emissions increases and decreases must be quantified.

Contemporaneous Period

The second step, under paragraph 72.b, is to determine the beginning and ending dates of the contemporaneous period. The contemporaneous period begins five years before the date construction is expected to commence. It is estimated that construction will begin 1 December 2001. Five years before this date is 1 December 1996. The contemporaneous

[1] *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting*, draft, October 1990 (final document never published). U.S. EPA, Office of Air Quality Planning and Standards.

period ends when the emissions increase from the modification occurs. This would be the date on which the Units 3 or 4 boilers would begin commercial operation, which is scheduled for 1 June 2004 for the first unit and June 2005 for the second unit. The contemporaneous period, therefore, is from 1 December 1996 to 1 June 2005.

Creditable Changes

The third step, under paragraphs 72.c through 72.f, is to determine which of the emission changes are creditable. There have been no creditable emissions increases or decreases at the TEP - SGS facility between December 1996 and the present. So, the only emission changes that must be addressed are the emission decreases that would occur at Unit 1 and Unit 2 under the voluntarily accepted emission caps proposed by the Permittee. Each of these changes meets the criteria set forth in paragraphs 72.c, d, and f:

- None of the decreases has been relied upon in issuing a permit.
- Each of the decreases will occur after the baseline date.
- The old level of actual emissions will exceed the new level of actual emissions by an amount equal to the maximum actual emissions from Unit 3 and Unit 4. This is ensured by setting the emission caps for SO_2, NO_X, and sulfuric acid mist at levels equal to the actual emissions of those pollutants from Units 1 and 2 during calendar years 1999 and 2000. The amount of each emission cap is discussed below.
- The enforceability of each of the decreases is ensured by including the emission caps in the proposed permit and by the inclusion of monitoring and reporting requirements that make the emission caps enforceable as a practical matter.
- The qualitative equivalence of the emissions decreases from Unit 1 and Unit 2 and the emissions increases from Unit 3 and Unit 4 has been demonstrated in dispersion modeling performed by the Department. (See Section VII herein for a discussion of the dispersion modeling analysis.) In addition, the Permittee is voluntarily accepting an SO_2 emission cap of 8,448 pounds per hour, on a three-hour average basis, total for Units 1-4, to ensure compliance with the corresponding SO_2 National Ambient Air Quality Standard.

Net Emissions Increase

The fourth and final step, under paragraphs 72.a.i through 72.a.ii, is to determine the net emissions increase by summing all creditable and contemporaneous emissions increases and decreases. Setting the emissions caps at levels equal to the past actual emissions from Unit 1 and Unit 2 will ensure that the decreases are at least equal to the increases, thus the net emissions increase cannot exceed zero and PSD applicability is not triggered for SO_2, NO_X, and sulfuric acid mist.

3. Determination of SO_2 Emission Cap

TEP - SGS is planning to implement a program of reducing the emissions of SO_2 from Units 1 and 2 at the same time that the construction of the first of the new Units 3 or 4 is

underway. The SO_2 reductions from Units 1 and 2 will be accomplished before the first of the new units 3 or 4 achieve commercial operation in June 2004. Since construction will commence in 2001, the two previous years are 1999 and 2000. For these two years, the total past actual emissions from Units 1 and 2 are 18,717 tons per year, based on CEMS data. (The actual SO_2 emission rate for Unit 1 in 1999 was 9,576.1 tons per year and in 2000 it was 9,035.5 tons per year. The actual SO_2 emission rate in 1999 for Unit 2 was 8,811.1 tons per year and in 2000 it was 10,012.9 tons per year. The average SO_2 emission rate for both units for both years is 18,717 tons per year.) This level of emissions will also be established as the SO_2 emission cap defined as the future potential to emit for Units 1, 2, 3, and 4 combined. The SO_2 emissions from all four units will be managed so that the total yearly emissions on a plant wide basis will not exceed the established level of 18,717 tons/yr.

TEP - SGS will need to make changes at Unit 1 and 2 in order to achieve the necessary decrease in SO_2 emissions. These changes will be made under the Pollution Control Project exclusion at A.A.C. R18-2-101.63.c.viii. Work associated with the changes will be completed prior to commercial operation of the first new unit scheduled for 2004. The emission reductions on Units 1 and 2 may be accomplished by adding and/or upgrading equipment on the existing spray dryers. A new Spray Dryer Absorber (SDA) module may need to be added on each unit. In addition, various pumps and system components may need to be enlarged to handle the increased flow of lime needed to remove the additional SO_2. Other available options for reducing the SO_2 emissions from Units 1 and 2 include the use of lower-sulfur coal or curtailing operations.

4. Determination of NO_X Emission Cap

TEP - SGS is planning to implement a program of reducing the emissions of NO_X from Units 1 and 2 at the same time that the construction of the first of the new Units 3 or 4 is underway. The NO_X reductions from Units 1 and 2 will be accomplished before the first of the new units 3 or 4 achieve commercial operation in June 2004. Since construction will commence in 2001, the two previous years are 1999 and 2000. For these two years, the total past actual emissions from Units 1 and 2 are 11,659 tons per year, based on CEMS data. (The actual NO_X emission rate for Unit 1 in 1999 was 5,767.3 tons per year and in 2000 it was 5,546.2 tons per year. The actual NO_X emission rate in 1999 for Unit 2 was 5,850.6 tons per year and in 2000 it was 6,154.0 tons per year. The average NO_X emission rate for both units for both years is 11,659 tons per year.) This level of emissions will also be established as the NO_X emission cap defined as the future potential to emit for Units 1,2,3, and 4 combined. The NO_X emissions from all four units will be managed so that the total yearly emissions on a plant wide basis will not exceed the established level of 11,659 tons/yr.

TEP - SGS will need to make changes at Unit 1 and 2 in order to achieve the necessary decrease in NO_X emissions. These changes will be made under the Pollution Control Project exclusion at A.A.C. R18-2-101.63.c.viii. Steps necessary to achieve the entire

emission reduction will be completed prior to commercial operation of Units 3 or 4 scheduled for June 2004. The burners installed in Units 1 and 2 may also be replaced with newer design low-NO_X burners. The boilers may also need to be altered to make changes to accommodate these new low-NO_X burners. Implementation of these changes would require an extended outage lasting six to eight weeks on each unit. Other available options for reducing the NO_X emissions from Units 1 and 2 include the use of lower-emitting coal (i.e., coal with a lower heating value and higher moisture content) or curtailing operations.

5. Determination of Sulfuric Acid Mist Emission Cap

TEP - SGS is planning to implement a program of reducing the emissions of sulfuric acid mist from Units 1 and 2 at the same time that the construction of the first of the new Units 3 or 4 is underway. The sulfuric acid mist reductions from Units 1 and 2 will be accomplished before either Unit 3 or Unit 4 achieves commercial operation. Since construction will commence in 2001, the two previous years are 1999 and 2000. For these two years, the total past actual emissions from Units 1 and 2 are 211.0 tons per year, based on SO_2 CEMS data and U.S. EPA published emission factors characterizing the ratio of SO_2 to sulfuric acid mist in coal-fired boiler exhaust. (Past actual sulfuric acid mist emissions are assumed to be equal to 1.127 percent of SO_2 emissions.) This level of emissions will also be established as the sulfuric acid mist emission cap defined as the future potential to emit for Units 1, 2, 3, and 4 combined. The sulfuric acid mist emissions from all four units will be managed so that the total yearly emissions on a plant wide basis will not exceed the established level of 211.0 tons/yr.

TEP - SGS will need to make changes at Units 1 and 2 in order to achieve the necessary decrease in sulfuric acid mist emissions. These changes will be made under the Pollution Control Project exclusion at A.A.C. R18-2-101.63.c.viii. Work associated with the changes will be completed prior to commercial operation of the first new unit scheduled for 2004. The emission reductions on Units 1 and 2 may be accomplished by adding and/or upgrading equipment on the existing spray dryers. A new Spray Dryer Absorber (SDA) module may need to be added on each unit. In addition, various pumps and system components may need to be enlarged to handle the increased flow of lime needed to control the additional sulfuric acid mist. Other available options for reducing the sulfuric acid mist emissions from Units 1 and 2 include the use of lower-sulfur coal or curtailing operations.

V. EMISSION LIMITS, TESTING, MONITORING, RECORDKEEPING, AND REPORTING

A. Units 3 and 4

Opacity: Each of the units is subject to an opacity standard of 15 percent, based on a six-minute rolling average, representing BACT. (See Section VI of this document for a discussion of the BACT analysis.) Other, less stringent opacity standards (such as that under 40 CFR part 60, subpart Da, §60.42a(b)) have been streamlined out of the permit.

The Permittee is required to operate a continuous monitoring system for opacity at all times when the units are in operation. The continuous opacity monitoring system is required to meet the performance specifications in 40 CFR part 60, appendix B. In addition, initial and annual performance tests using EPA Method 9 are required.

PM: For the purposes of establishing and demonstrating compliance with the boiler emission limits, PM is defined to include only filterable particulate matter as measured by EPA Reference Method 5. See Section VI.A.1 herein for further discussion of the differences between PM and PM-10.

Each of the units is subject to a filterable PM standard of 0.015 lb/MMBtu heat input, based on a three-hour averaging period, representing BACT. (See Section VI of this document for a discussion of the BACT analysis.) Other, less stringent PM standards (such as that under 40 CFR part 60, subpart Da, §60.42a(a)) have been streamlined out of the permit.

The requirements of the CAM rule, codified at 40 CFR part 64, are applicable to the PM emission standard for Unit 3 and Unit 4. This rule implements §§114(a)(1) and (a)(3) of the Clean Air Act, as amended, and applies wherever the following three criteria are met:

> The emission unit is subject to an emission limitation or standard[2] for a particular pollutant;
>
> The emission unit uses a control device to achieve compliance with the emission limitation or standard; and
>
> The emission unit has potential, pre-control device emissions greater than the applicable major source threshold.

[2] There are several emission standards that are specified in the CAM rule as being exempt from CAM requirements.

The CAM rule allows for two general approaches: continuous monitoring to determine compliance directly, such as using a continuous emission monitoring system (CEMS), or monitoring of control device operation within specified ranges of performance to provide reasonable assurance of compliance.

The applicant submitted a CAM plan that relies upon the use of a bag leak detector as the primary indicator of compliance. The permit includes provisions requiring adherence to this CAM plan. In addition, initial and annual performance tests using EPA Method 5 are required.

PM-10: For the purposes of establishing and demonstrating compliance with the boiler emission limits, PM-10 is defined to include both fine filterable particulate matter and condensible particulate matter as measured by EPA Reference Methods 201A and 202, respectively. See Section VI.A.1 herein for further discussion of the differences between PM and PM-10.

Each of the units is subject to a PM-10 standard of 0.055 lb/MMBtu heat input, based on a three-hour averaging period, representing BACT. (See Section VI of this document for a discussion of the BACT analysis.)

CAM requirements under 40 CFR part 64 are applicable. The applicant submitted a CAM plan that relies upon the use of a bag leak detector as the primary indicator of compliance. The permit includes provisions requiring adherence to this CAM plan. In addition, initial and annual performance tests using EPA Method 5 or 201 or 201A for the filterable fraction plus EPA Method 202 for the condensible fraction are required.

SO_2: Each of the units is subject to several different SO_2 emission standards with different averaging periods and forms of expression. First, each unit is subject to the SO_2 standard under 40 CFR part 60, subpart Da, §60.43a(a), which requires that either a specified emission rate or a specified control efficiency be achieved. Second, each unit is subject to the Acid Rain Program provisions at 40 CFR part 72, which requires that the Permittee hold allowances for all SO_2 emissions. Third, the total SO_2 emissions from Unit 1 through Unit 4 are subject to a short-term emission cap of 8,448 lb/hr (based on a three-hour rolling average). This short-term emission cap is sufficient to ensure compliance with the SO_2 National Ambient Air Quality Standards and PSD Increment, as discussed in Section VII herein. Fourth, the total SO_2 emissions from Unit 1 through Unit 4 are subject to an emission cap of 18,717 tons/yr, calculated on a rolling 12-month sum basis. This emission cap is sufficient to ensure that the project does not result in a significant net emissions increase, as

explained in Section IV.B herein. Fifth, the total SO_2 emissions from Unit 1 through Unit 4 are subject to an emission cap of 13,300 tons/yr, calculated on a rolling 12-month sum basis, effective on January 1, 2011. This is a voluntarily accepted emission limitation and is not required by any applicable regulation.

The Permittee is required to operate continuous emissions monitoring systems (CEMS) for recording SO_2 emissions from each unit. These CEMS are required to meet the requirements of 40 CFR part 60, appendices B and F, and 40 CFR part 75, appendices A and B. These CEMS will be used to demonstrate compliance with all SO_2 emission standards. The CEMS also are used for the required initial performance tests.

CAM requirements under 40 CFR part 64 are not applicable to the SO_2 emission standards for Unit 3 and Unit 4 because each of these emission standards is exempted under 40 CFR 64.b(1). The NSPS standards are exempt under §64.b(1)(vi) because the regulation includes a continuous compliance determination method. The voluntarily accepted emission caps are exempt under §64.b(1)(v) because they meet the requirements under 40 CFR 70.4(b)(12). The applicable Acid Rain Program emission standards are specifically exempted under §64.b(1)(iii).

It should be noted that compliance with the annual emission cap is required by the permit. One of the measures available to the Permittee for complying with the emission cap is to halt or reduce operation. A.A.C. R18-2-306 provides that needing to halt or reduce operation in order to comply with a permit condition does not constitute a defense in an enforcement action. In addition, A.R.S. §49-462 provides that the Director may file an action for injunctive relief, which may include shutdown of the source, if a violation of a permit term occurs.

NO_X: Each of the units is subject to the NSPS NO_X standard under 40 CFR part 60, subpart Da, §60.44a(d)(1), and the Acid Rain Program NO_X standard under 40 CFR part 76. In addition, the total NO_X emissions from Unit 1 through Unit 4 are subject to an emission cap of 11,659 tons/yr, calculated on a rolling 12-month sum basis. This emission cap is sufficient to ensure that the project does not result in a significant net emissions increase, as explained in Section IV.B herein.

The Permittee is required to operate continuous emissions monitoring systems (CEMS) for recording NO_X emissions from each unit. These CEMS are required to meet the requirements of 40 CFR part 75, appendices A and B. These CEMS will be used to demonstrate

compliance with all NO_X emission standards. The CEMS also are used for the required initial performance tests.

CAM requirements under 40 CFR part 64 are not applicable to the NO_X emission standards for Unit 3 and Unit 4 because each of these emission standards is exempted under 40 CFR 64.b(1). The NSPS standards are exempt under §64.b(1)(vi) because the regulation includes a continuous compliance determination method. The voluntarily accepted emission cap is exempt under §64.b(1)(v) because it meets the requirements under 40 CFR 70.4(b)(12). The applicable Acid Rain Program emission standard is specifically exempted under §64.b(1)(iii).

It should be noted that compliance with the annual emission cap is required by the permit. One of the measures available to the Permittee for complying with the emission cap is to halt or reduce operation. A.A.C. R18-2-306 provides that needing to halt or reduce operation in order to comply with a permit condition does not constitute a defense in an enforcement action. In addition, A.R.S. §49-462 provides that the Director may file an action for injunctive relief, which may include shutdown of the source, if a violation of a permit term occurs.

CO: Each of the units is subject to a CO standard of 0.15 lb/MMBtu heat input, based on a 30-day rolling average, representing BACT. (See Section VI of this document for a discussion of the BACT analysis.) The Permittee is required to operate continuous emissions monitoring systems (CEMS) for recording CO emissions from each unit. These CEMS are required to meet the requirements of 40 CFR part 60, appendices B and F. The CEMS also are used for the required initial performance tests.

CAM requirements under 40 CFR part 64 are not applicable to the CO emission standard for Unit 3 and Unit 4 because no control device is used to achieve compliance.

VOC: Each of the units is subject to a VOC standard of 0.06 lb per ton of coal combusted, based on a three-hour averaging period, representing BACT. (See Section VI of this document for a discussion of the BACT analysis.) The Permittee is required to perform initial and annual performance tests using EPA Method 18 or 25.

CAM requirements under 40 CFR part 64 are not applicable to the CO emission standard for Unit 3 and Unit 4 because no control device is used to achieve compliance.

HF: Each of the units is subject to a hydrogen fluoride standard of 0.00044

lb/MMBtu heat input, based on a three-hour rolling average. This standard represents BACT for fluorides and case-by-case MACT for hydrogen fluoride. (See Section VI of this document for a discussion of the BACT and MACT analyses.)

CAM requirements under 40 CFR part 64 are applicable to the HF emission standard for Unit 3 and Unit 4 . (See the PM discussion above for a summary of these requirements.) The applicant submitted a CAM plan that relies upon the use of the monitored SO_2 emission rate as the primary indicator of compliance with the HF emission standard. The permit includes provisions requiring adherence to this CAM plan, including an initial verification test to establish the relationship between SO_2 and HF emission rates. (A strong linear relationship is expected to exist because both SO_2 and HF are acid gases that will be controlled by absorption in the spray dry absorbers and capture in the fabric filter baghouse.) In addition, initial performance tests using EPA Method 26A are required. Once the ratio of SO_2 to HF emission rates is established for each of the four boilers, the monitored SO_2 emission rates will be used to calculate the HF emissions on a three-hour rolling average basis.

Lead: Each of the units is subject to a lead standard of 0.000016 lb/MMBtu heat input, based on a three-hour averaging period. This emission limitation is necessary and sufficient to ensure that the proposed modification (including both Unit 3 and Unit 4) will not result in a significant net emissions increase and, thus, will not be subject to PSD review for lead emissions. The Permittee is required to perform initial and annual performance tests using EPA Method 12 or 29. The permit includes provisions for cancelling subsequent performance tests in the event that the initial performance test shows emissions less than 50 percent of the standard.

CAM requirements under 40 CFR part 64 are not applicable to the lead emission standard for Unit 3 and Unit 4 because the potential pre-control device emissions are less than 100 tons per year.

H_2SO_4: The total emissions of sulfuric acid mist from Unit 1 through Unit 4 are subject to an emission cap of 211.0 tons/yr, calculated on a rolling 12-month sum basis. This emission cap is sufficient to ensure that the project does not result in a significant net emissions increase, as explained in Section IV.B herein.

The applicant submitted a monitoring plan that relies upon the use of the monitored SO_2 emission rate as the primary indicator of compliance with the sulfuric acid mist emission cap. The permit includes provisions

requiring adherence to this monitoring plan, including an initial verification test to establish the relationship between SO_2 and sulfuric acid mist emission rates. (A strong linear relationship is expected to exist because both SO_2 and SO_3, from which sulfuric acid mist is formed, are acid gases that will be controlled by absorption in the spray dry absorbers and capture in the fabric filter baghouse.) In addition, initial performance tests using EPA Method 8 are required. Once the ratio of SO_2 to sulfuric acid mist emission rates is established for each of the four boilers, the monitored SO_2 emission rates will be used to calculate the sulfuric acid mist emissions on a 12-month rolling-sum basis.

CAM requirements under 40 CFR part 64 are not applicable to the sulfuric acid mist emission cap. This emission cap is exempted under 40 CFR 64.b(1)(v) because it meets the requirements under 40 CFR 70.4(b)(12).

It should be noted that compliance with the annual emission cap is required by the permit. One of the measures available to the Permittee for complying with the emission cap is to halt or reduce operation. A.A.C. R18-2-306 provides that needing to halt or reduce operation in order to comply with a permit condition does not constitute a defense in an enforcement action. In addition, A.R.S. §49-462 provides that the Director may file an action for injunctive relief, which may include shutdown of the source, if a violation of a permit term occurs.

Mercury: Each of the units is subject to a mercury standard of 0.0000069 lb/MMBtu heat input, based on a three-hour averaging period, representing case-by-case MACT. (See Section VI of this document for a discussion of the MACT analysis.) The Permittee is required to perform initial and annual performance tests using EPA Method 29.

CAM requirements under 40 CFR part 64 are not applicable to the mercury emission standard for Unit 3 and Unit 4 because the potential pre-control device emissions are less than 100 tons per year.

Fuel Use: The Permittee is restricted to using coal and No. 2 distillate fuel oil as fuels in each of the steam generating units. Heat input to each unit is limited to 4,200 MMBtu/hr, based on a 30-day rolling average. These restrictions are needed to ensure the enforceability of the representations made in the permit application, because these representations form the basis of all regulatory and technical analyses performed by the Department. The Permittee is required under Acid Rain Program regulations to determine and record the heat input to each unit on an hourly basis.

Other: Each of the units is subject to other monitoring requirements that are needed, in conjunction with the monitoring described above, in order to demonstrate compliance with all applicable emission standards using all applicable averaging periods and forms of expression. For instance, the Permittee is required to operate wattmeters to record continuously the electrical output of each unit. This parameter is needed in order to demonstrate compliance with the NO_X standard under 40 CFR part 60, subpart Da, which is expressed in units of pounds per megawatt-hour.

B. Units 1 and 2

SO_2: An alternate operating scenario has been established for Units 1 and 2. This alternate operating scenario takes effect if Unit 3 or Unit 4 commences operation. Under this alternate operating scenario, all existing emission limitations continue to apply, and the following new requirements become effective: First, Units 1 and 2 are subject to voluntarily accepted SO_2 emission limitations equivalent to those under NSPS Subpart Da. (The permit includes language like that in NSPS Subpart Da, which allows emissions of up to 1.2 lb per MMBtu heat input if 90 percent control is being achieved. Compliance with the existing limit of 0.69 lb per MMBtu heat input is still required.) Second, the total SO_2 emissions from Unit 1 through Unit 4 are subject to emission caps of 8,448 lb/hr and 18,717 tons/yr. Third, the long-term SO_2 emissions cap decreases to 13,300 tons/yr, effective on January 1, 2011. The monitoring requirements for these emission caps are described above.

NO_X: An alternate operating scenario has been established for Units 1 and 2. This alternate operating scenario takes effect if Unit 3 or Unit 4 commences operation. Under this alternate operating scenario, all existing emission limitations continue to apply, and one new requirement becomes effective: total NO_X emissions from Unit 1 through Unit 4 are subject to an emission cap of 11,659 tons/yr. The monitoring requirements for this emission cap are described above.

H_2SO_4: An alternate operating scenario has been established for Units 1 and 2. Under this alternate operating scenario, which takes effect if Unit 3 or Unit 4 commences operation, the total emissions of sulfuric acid mist from Unit 1 through Unit 4 are subject to an emission cap of 211.0 tons/yr. The monitoring requirements for this emission cap are described above.

C. Cooling Towers 3 and 4

PM: Each of these units is subject to a limitation on maximum circulating water flow rate equal to 200,00 gallons per minute in each cooling tower.

Compliance with this limit is demonstrated by maintaining records of design maximum pumping capacity. Each cooling tower also is required to be equipped with high-efficiency drift eliminators designed for a maximum total liquid drift not to exceed 0.0005 percent of circulating water flow rate. Compliance with this requirement is demonstrated by maintaining records of the vendor-guaranteed maximum total liquid drift. Finally, each cooling tower is subject to a PM emission standard of 24.64 lbs/hr. The Permittee is required to perform monthly measurements of the total dissolved solids content of the circulating water. Compliance with the PM emission standard is required to be demonstrated by performing monthly calculation of PM emissions from each cooling tower using design maximum pumping capacity, vendor-guaranteed maximum total liquid drift, and the actual measured total dissolved solids content of the circulating water. Records of all measurements and calculations are required to be maintained.

Each of these units also is subject to particulate matter emission standard in A.A.C. R18-2-730A.1. Compliance with this standard is demonstrated through compliance with the above provisions, as testing of PM emission rate from the cooling tower is not feasible.

D. Cooling Towers 1 and 2

PM: The existing cooling towers are not being modified, and no revisions to the existing permit terms for these units are proposed. However, an alternate operating scenario has been established for Cooling Towers 1 and 2. Under this alternate operating scenario, which takes effect if Unit 3 or Unit 4 commences operation, these cooling towers are subject to voluntarily accepted equipment standards and emission limitations designed to ensure facility-wide compliance with limitations on PSD increment consumption. (See Section VII herein for a discussion of ambient air quality impact analysis.) First, the circulating water flow rate is limited to 176,00 gallons per minute in each cooling tower. Compliance with this limit is demonstrated by maintaining records of design maximum pumping capacity. Second, each cooling tower is required to be equipped with high-efficiency drift eliminators designed for a maximum total liquid drift not to exceed 0.005 percent of circulating water flow rate. Compliance with this requirement is demonstrated by maintaining records of the vendor-guaranteed maximum total liquid drift. Finally, each cooling tower is subject to a PM emission standard of 216.8 lbs/hr. The Permittee is required to perform monthly measurements of the total dissolved solids content of the circulating water. Compliance with the PM emission standard is required to be demonstrated by performing monthly calculation of PM emissions from each cooling tower using design

maximum pumping capacity, vendor-guaranteed maximum total liquid drift, and the actual measured total dissolved solids content of the circulating water. Records of all measurements and calculations are required to be maintained..

Each of these units also is subject to particulate matter emission standard in A.A.C. R18-2-730A.1. Compliance with this standard is demonstrated through compliance with the above provisions, as testing of PM emission rate from the cooling tower is not feasible.

E. Coal Preparation Plant

Opacity: The existing coal preparation plant, which excludes the coal storage piles, already is subject to the 20 percent opacity standard under 40 CFR 60, Subpart Y. In addition, the existing coal storage piles are subject to an opacity standard of 40 percent. The existing Title V permit requires that the Permittee conduct a weekly survey of the visible emissions from the coal preparation plant and the coal storage piles; create a record of the date on which the survey was taken, the name of the observer, and the results of the survey; and conduct Method 9 opacity observations if opacity approaching the standard is observed.

The proposed permit revisions will add to the existing requirements. Once the alternate operating scenario is activated (by startup of Unit 3 or Unit 4 or by commencing physical changes to the coal preparation plant), a 10 percent opacity limit takes effect for the coal preparation plant fabric filter baghouses. The existing monitoring, testing, recordkeeping, and reporting provisions will continue, but the threshold for conducting a Method 9 opacity observation at a fabric filter baghouse is lowered to 10 percent from 20 percent.

PM: The existing coal preparation plant is not subject to any PM emission standards. The proposed permit revisions will add a PM emission standard under an alternative operating scenario. Once the alternate operating scenario is activated (by startup of Unit 3 or Unit 4 or by commencing physical changes to the coal preparation plant), all coal preparation plant fabric filter baghouses must meet a minimum design specification. This specification requires a maximum outlet particulate matter concentration of 0.01 grains per dry standard cubic foot of exhaust. The Permittee is required to hold these specifications on file. Records of fabric filter baghouse maintenance are required.

F. Lime and Fly Ash Handling

Existing Equipment: The existing lime and fly ash handling facilities are not being modified. No changes to the existing permit terms for these facilities are being proposed. Entirely new lime and fly ash handling facilities are being constructed for the two new boilers.

Opacity: The proposed new lime and fly ash handling operations are subject to the 40 percent opacity standard in A.A.C. R18-2-702.B.1. In addition, the lime and fly ash handling system fabric filter baghouses are subject to a 10 percent opacity standard representing BACT. The proposed permit requires that the Permittee conduct a weekly survey of the visible emissions from the lime and fly ash handling operations; create a record of the date on which the survey was taken, the name of the observer, and the results of the survey; and conduct Method 9 opacity observations if opacity approaching the applicable standard is observed.

PM: The lime and fly ash handling operations are subject to the particulate matter standard in A.A.C. R18-2-730.A.1.a and b. Compliance with this standard will be demonstrated through the visible emissions surveys described above. In addition, the fabric filter baghouses are required to be designed for maximum outlet particulate matter concentration of 0.01 grains per dry standard cubic foot of exhaust. The Permittee is required to hold these specifications on file. Records of fabric filter baghouse maintenance are required.

G. Non-Point Sources

PM: Non-point sources at the SGS include open areas, roadways, and streets, including the ash haul road. Under the existing Title V permit, these sources are subject to general opacity and work practice requirements. The proposed permit revisions will add, under an alternative operating scenario, a pollution control equipment standard for the ash haul road. Once the alternate operating scenario is activated (by startup of Unit 3 or Unit 4 or by commencing physical changes to the coal preparation plant), vehicular and non-vehicular traffic on the ash haul road are prohibited unless the ash haul road is equipped with an effective oil-and-chip surface, including an appropriate load-bearing base as required to control dust emissions, and unless the road has been watered within the most recent 24 hours.

VI. CONTROL TECHNOLOGY ANALYSES

A. BEST AVAILABLE CONTROL TECHNOLOGY

As noted in Section IV.A herein, PSD regulations under Title I of the Federal Clean Air Act and R18-2-406.A are applicable to the proposed expansion of the TEP - SGS facility. The PSD regulations are applicable on a pollutant-specific basis. The proposed expansion of the TEP - SGS facility is subject to the PSD provisions for five pollutants: PM, PM_{10}, CO, VOC, and fluorides. (See Section IV.B herein for a discussion of the PSD non-applicability determination for other PSD-regulated pollutants, including SO_2, NO_X, lead, and sulfuric acid mist.)

One of the substantive requirements under the PSD regulations is that the Best Available Control Technology, or "BACT," must be applied to each new or modified emission unit at which an emission increase of a PSD-subject pollutant will occur as a result of the project. For the purposes of the proposed expansion of the TEP - SGS facility, BACT is required for the two new boilers for each of the five PSD-regulated pollutants listed above. In addition, BACT is required for PM and PM_{10} for the new lime and fly ash handling operations and for the modified coal preparation plant and non-point sources. (These sources are not expected to emit any of the other pollutants for which PSD applicability is triggered.)

The term "best available control technology" is defined at A.A.C. R18-2-101.19 as follows:

> "an emission limitation, including a visible emissions standard, based on the maximum degree of reduction for each air pollutant listed in R18-2-101(97)(a) which would be emitted from any proposed major source or major modification, taking into account energy, environmental, and economic impact and other costs, determined by the Director in accordance with R18-2-406(A)(4) to be achievable for such source or modification."

The U.S. EPA's definitive guidance for performing a top-down BACT analysis is set forth in Chapter B of the October 1990 New Source Review Workshop Manual.[3] This guidance dictates that BACT analyses and determinations be performed on a source-by-source and pollutant-by-pollutant basis using the following five key steps:

<u>Identify all control technologies.</u> For BACT purposes, "available" control options are those technologies or techniques with a practical potential for application to the subject emission units and pollutants. These may include fuel cleaning or treatment,

[3] *New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting*, draft, October 1990 (final document never published). U.S. EPA, Office of Air Quality Planning and Standards.

inherently lower-polluting processes, and end-of-pipe control devices. All identified options are listed in this step; those that are identified as being technically infeasible or as having unacceptable energy, economic or environmental impacts are eliminated in subsequent steps.

Eliminate technically infeasible options. In this step, the technical feasibility of each identified control option is evaluated with respect to source-specific factors. Demonstrations of technical infeasibility must show, based on physical, chemical and engineering principles, that technical difficulties would preclude the control option from being employed successfully on the subject emissions unit.

Rank remaining control technologies by control effectiveness. All remaining control alternatives not eliminated in step 2 are ranked and listed in order of overall control effectiveness for the pollutant under review. For each option, estimated control efficiency and overall emissions reduction must be documented.

Evaluate most effective controls and document results. Beneficial and adverse energy, environmental and economic impacts of each remaining control option are listed and considered. If the best option (i.e., the option with the highest control effectiveness as ranked in step 3) is rejected as BACT due to unacceptable energy, environmental or economic impacts, the rationale must be documented for the public record and the next-best control option subjected to the same evaluation.

Select BACT. Finally, the most effective control technology not eliminated in the previous step is proposed as BACT.

The NSR Workshop Manual also notes that, to complete the BACT process, an enforceable emission limit representing BACT must be included in the PSD permit. This emission limit must be met on a continual basis at all levels of operation, must demonstrate protection of short term ambient standards, and must be enforceable as a practical matter. In order for the emission limit to be enforceable as a practical matter, the permit must specify a reasonable compliance averaging time, consistent with established reference methods, and must include compliance verification procedures (i.e., monitoring requirements) designed to show compliance or non-compliance on a time period consistent with the applicable emission limit.

Materials considered by the applicant and by the Department in identifying and evaluating available control options include the following:

Entries in the RACT/BACT/ LAER Clearinghouse maintained by the U.S. EPA. This database is the most comprehensive and up-to-date listing of control technology determinations available.
Information provided by pollution control equipment vendors.
Information provided by industry representatives and by other State permitting

authorities. This information is particularly valuable in clarifying or updating control technology information that has not yet been entered into the RACT/BACT/ LAER Clearinghouse.

The BACT evaluations and proposed BACT determinations for each of the new and modified emission units at the TEP - SGS facility are discussed in the following paragraphs:

1. Units 3 and 4 - PM and PM-10 Emissions

The composition and amount of particulate matter emitted from coal-fired boilers are a function of firing configuration, boiler operation, coal properties and emission controls. Particulate matter will be emitted from the boilers as a result of entrainment of incombustible inert matter (ash) and condensible substances. Trace heavy metals contained in coal are also emitted, such as lead, beryllium and arsenic, which form a fraction of the coal ash.

For this analysis, it is important to note that PM is defined as filterable particulate matter as measured by EPA Reference Method 5. This test method measures all particulate matter that is collected on a glass fiber filter at a temperature of approximately 120 ºC; substances that are in the vapor phase at this temperature, although they may contribute to ambient particulate matter concentrations, are not measured.

For this analysis, PM-10 is defined to include both fine filterable particulate matter and condensible particulate matter as measured by EPA Reference Methods 201A and 202, respectively. Method 201A measures all particulate matter having an aerodynamic diameter equal to or less than nominally 10 micrometers (10^{-6} meters) that is collected on a glass fiber filter at the stack temperature. Method 201A will generally yield a slightly smaller result than Method 5 because particles having an aerodynamic diameter nominally 10 micrometers or greater are excluded. Method 202 measures all particulate matter that condenses at a temperature of approximately 20 ºC after passing through a fabric filter such as that used in Method 201A. The total PM-10, which is the combined result of performing Method 201A and Method 202 simultaneously, may be substantially different than the PM as measured by Method 5.

<u>Step 1 - Identify All Control Technologies</u>

Three control technologies for the boilers have been identified for PM/PM-10 control for the PC boilers:

- Electrostatic precipitators (ESPs);
- Fabric filter baghouses
- Wet control techniques (scrubbers)

Electrostatic precipitation technology is applicable to a variety of coal combustion sources. ESPs remove particulate matter from the flue gas stream by charging fly ash particles with a very high dc voltage and attracting these particles to oppositely charged collection plates. A layer of collected particulate forms on the collecting plates (electrodes) and is removed by rapping the electrodes. The collected ash particles drop into hoppers below the precipitator and are periodically removed from the fly ash handling system. Electrostatic precipitators are a technically feasible control option for filterable particulate matter from the proposed boilers.

Fabric filtration has been widely applied to coal combustion sources since the early 1970s and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fiberglass or other fabric bags as filters to collect particulate matter. The particulate-laden gas enters a fabric filter compartment and passes through the bags and through a layer of accumulated particulate matter collected on the fabric of the filter bags. The collected particulate matter forms a filter cake layer on the bag that enhances the bag's filtering efficiency. However, excessive caking will increase the pressure drop across the fabric filter. When this occurs, the fabric filter is placed into a cleaning cycle and the excess particulate matter is removed to the ash collection system. Fabric filters are effective in meeting NSPS emission requirements on coal-fired boilers. Fabric filters have been used as a control technology of choice on projects where LAER review is required. Unlike precipitators, fabric filter design is not based on physical properties of the fly ash. Fabric filter baghouses are a technically feasible control option for filterable particulate matter from the proposed boilers.

Wet scrubbing technology uses water to increase the size of the particle, which allows the settling of the particle from the gas stream. Wet scrubbers are a technically feasible control option for filterable particulate matter from the proposed boilers.

Step 2 - Eliminate Technically Infeasible Options

No technically infeasible particulate matter control options were identified.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

As discussed below, fabric filter baghouses are the top control option for coal-fired boilers.

The fabric filter is more effective at capturing fine particulate than an ESP because ESP's tend to selectively collect larger particles. Large particles have a high mass to surface area ratio, which allows a charged particle to be efficiently dragged through the flue gas stream for collection on a charged plate. Ultra fine particles have a low terminal velocity and cannot carry a strong enough electrical charge to result in complete collection. The fabric filter is also more effective at collecting fly ash generated from western low sulfur

coals such as those combusted at Springerville. ESP's operate by first electrostatically charging for collection and then discharging the fly ash particles for removal in the ash handling system. Western low sulfur coal fly ash has a very high electrical resistivity that makes it difficult for the ESP to charge and discharge the particles. One solution that has been attempted on western power plants is the use of a hotside precipitator that operates at approximately 800º F as opposed to approximately 250º F operating temperature used on most ESP's. However even with this change in operating temperature, the ESP is still less effective at collecting fly ash in western power plants than is the fabric filter baghouse.

Wet scrubbers have not been demonstrated to achieve control effectiveness similar to either ESP's or fabric filter baghouses.

Step 4 - Evaluate Most Effective Controls and Document Results

Fabric filter baghouses are the top control option for particulate matter emissions from coal-fired boilers. This technology does not have any adverse energy, environmental, or economic impacts. Therefore, fabric filter baghouse technology was proposed by the Permittee as BACT, and the Department agrees with this technology selection.

Step 5 - Select BACT

In its initial permit application, the Permittee proposed 0.02 lb/MMBtu heat input as the BACT emission limit for PM. Consistent with the format used for most recent BACT determinations nationwide for coal-fired boilers, the Permittee also proposed 0.02 lb/MMBtu heat input as the BACT emission limit for filterable PM-10, with no emission limit for total or condensible PM-10. (All listings for PM-10 in the RACT/BACT/LAER Clearinghouse and all but two recent permits identified by the Permittee reference only filterable PM and PM-10 emissions from coal-fired boilers.) The proposed control level of 0.02 lb/MMBtu heat input is equivalent to the most stringent limits achieved by PC boilers.

Based on further review by the Department of the control level achievable with a fabric filter baghouse, more stringent PM and filterable PM-10 emission rates have been established for circulating fluidized-bed (CFB) boilers using fabric filter baghouses. Adjusting for differences in exhaust gas characteristics, these more stringent limits are approximately equivalent to 0.015 lb/MMBtu heat input for PC boilers burning sub-bituminous coal. The Permittee adjusted its BACT proposal to reflect this value as the proposed emission limit for PM and filterable PM-10. The Department agrees that this proposal represents BACT for PM.

The Department elected not to establish a separate BACT emission limit for the filterable fraction of PM-10 emission. Instead, the Department elected to establish a single BACT emission limit for total PM-10, including both filterable and condensible fractions.

Accordingly, at the request of the Department, the Permittee proposed a BACT emission limit of 0.055 lb/MMBtu heat input for total PM-10. This emission limit is based upon 0.015 lb/MMBtu for filterable PM-10 and 0.040 lb/MMBtu for condensible PM-10. No PM-10 control option that is more effective than the proposed fabric filter baghouse has been identified, and no more stringent limit has been achieved in practice. The Department agrees that this proposal represents BACT.

2. Units 3 and 4 - CO and VOC Emissions

Carbon monoxide (CO) and Volatile Organic Compounds (VOC) are formed as a result of incomplete combustion of a hydrocarbon fuel. CO and VOC emissions from pulverized coal-fired boilers are a function of oxygen availability (excess air), flame temperature, residence time at flame temperature, combustion zone design, and turbulence.

Step 1 - Identify All Control Technologies

All pulverized coal boilers identified utilize process design for efficient combustion as the primary means of control of CO and VOC emissions. Control of CO and VOC is accomplished by providing adequate fuel residence time, excess oxygen and high temperature in the combustion zone to ensure complete combustion. These control factors, however, also tend to result in increased emissions of NO_X. Conversely, a low NO_X emission rate achieved through combustion modification techniques such as staged combustion can result in higher levels of CO and VOC emissions. Thus, a compromise is established to achieve the lowest NO_X emission rate possible while keeping CO emission rates at acceptable levels.

Three control technologies were identified for potential consideration for control of CO and VOC:

- Combustion controls;
- Catalytic Oxidation; and
- SCONOx;

SCONOx and catalytic oxidation are post-combustion control devices that would be applied to the combustion system exhaust, while combustion controls are part of the combustion system design.

Step 2 - Eliminate Technically Infeasible Options

Catalytic oxidation has been the control alternative used to obtain the most stringent control level for CO and VOCs emitting from primarily combustion turbines firing natural gas. This alternative, however, has never been applied to a coal-fired unit. For

sulfur containing fuels, such as coal, an oxidation catalyst would convert sulfur dioxide to sulfur trioxide, which in turn would form sulfuric acid, and therefore this conversion would result in unacceptable levels of corrosion to the flue gas system and unacceptable sulfate emissions to the atmosphere. The proposed TEP - SGS boilers will have a particulate loading upstream of the fabric filter baghouse in excess of that which oxidation catalysts are designed. In addition, trace elements present in coal, in particular chlorine, are poisonous to oxidation catalysts. There are no oxidation catalysts developed that have or can be applied to coal- or oil-fired boilers due to the high levels of particulate matter and widely variable trace elements present in the flue gas. The catalyst could not be installed downstream of the spray dryer/fabric filter since the flue gas temperature at that point will be approximately 150 ºF, which is well below the minimum temperature required (600 ºF) for operation of oxidation catalyst. For these reasons, as well as the generally low level of CO and VOC in coal-fired units, no PC boilers have been equipped with oxidation catalysts. For these reasons, use of an oxidation catalyst system in the proposed boilers is considered technically infeasible.

SCONOx is a technology that has been widely discussed for application to many types of sources, however to date the only two known applications are on small natural gas-fired turbine cogeneration systems. Like oxidation catalyst, this technology has never been applied or even tested for application to coal-fired boilers. In fact, SCONOx actually utilizes the same CO reduction technology and has the same technical limitations as an oxidation catalyst discussed previously. The SCONOx bed incorporates a coating of the same catalyst material, primarily to oxidize NO to NO_2 but with the side benefit of also destroying CO. SCONOx therefore has all the limitations cited above for oxidation catalyst, but is even further from consideration as potential transferable technology for this application.

All listings in EPA's RACT/BACT/LAER Clearinghouse for pulverized coal-fired boilers utilize combustion control techniques for CO and VOC emission control. This technology is technically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Based on the Step 2 analysis, combustion control is the only technology that is technically feasible and demonstrated in practice for this application.

Step 4 - Evaluate Most Effective Controls and Document Results

Based on the Step 2 analysis, combustion control is the only technology that is technically feasible and demonstrated in practice for this application. Therefore, combustion control was proposed by the Permittee as BACT, and the Department agrees with this technology selection.

Step 5 - Select BACT

The Permittee proposed combustion control, and emission limits of 0.15 lb CO per MMBtu heat input and 0.06 lb VOC per ton of coal combusted, as BACT for Unit 3 and Unit 4. As noted above, combustion modifications to reduce CO emissions below this level are achievable, but this would come at the expense of relative increases in uncontrolled NO_X emissions. This increase in uncontrolled NO_X emissions would require a more robust SCR system and greater ammonia injection rates in order to maintain compliance with the applicable NO_X emission standard under NSPS subpart Da.

At the Department's request, the Permittee performed an evaluation of the economic feasibility of using a more robust SCR system, with greater ammonia injection rates, in order to achieve a higher level of CO emission control. The Permittee identified 0.24 lb NO_X per MMBtu heat input as the uncontrolled NO_X emission level that is achievable with combustion controls that simultaneously achieve a CO emission level of 0.15 lb per MMBtu heat input. The Permittee also identified 0.59 lb per MMBtu heat input as the most stringent CO emission level achievable with combustion controls and determined that 0.38 lb NO_X per MMBtu heat input is the uncontrolled NO_X emission level achievable with these combustion modifications. This control alternative would result in lower CO emissions by 1,674 tons per year. The Permittee determined that the incremental capital cost of the more robust SCR system would be approximately $26 million and that this system would require an additional 1,681 tons of ammonia per year. The incremental cost difference of $6,000 per ton of CO reduction is not feasible.

For these reasons, the Department agrees with the preliminary BACT determination proposed by the Permittee.

3. Units 3 and 4 - Fluoride Emissions

Fluoride emissions from coal-fired boilers, primarily in the form of hydrogen fluoride, result from trace concentrations of fluoride-containing compounds in the fuel.

<u>Step 1 - Identify All Control Technologies</u>

Three control technologies for the boilers have been identified for fluoride emissions control for the PC boilers:

- Spray dry absorbers in combination with electrostatic precipitators (ESPs);
- Spray dry absorbers in combination fabric filter baghouses; and
- Caustic wet scrubbers.

Note that "no control" is not a control option under consideration for the fluoride BACT determination. One of the three control options listed above must be used to achieve the minimum level of control required by applicable PM and SO_2 emission standards under NSPS Subpart Da.

Step 2 - Eliminate Technically Infeasible Options

No technically infeasible control options for fluoride emissions were identified.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Spray dry absorbers in conjunction with fabric filter baghouses comprise the top control option. As noted in the particulate matter BACT analysis herein, ESP's are less effective than fabric filter baghouses for collecting fine particles in coal-fired boiler exhaust, which is the mechanism used for fluoride emissions control. Wet scrubbing has not been demonstrated to achieve control levels equivalent to those achievable by spray dry absorbers in conjunction with effective particulate matter control technologies.

Step 4 - Evaluate Most Effective Controls and Document Results

Spray dry absorbers in conjunction with fabric filter baghouses comprise the top control option for the proposed TEP - SGS boilers. This technology does not have any adverse energy, environmental, or economic impacts. Therefore, spray dry absorbers in conjunction with fabric filter baghouses was proposed by the Permittee as BACT, and the Department agrees with this technology selection.

Step 5 - Select BACT

The Permittee proposed a BACT emission limit 0.00042 lb fluorides per MMBtu heat input. This is equivalent to the lowest identified emission limit for fluorides for any coal-fired boiler of any type, and the Department agrees that this proposal represents BACT.

The BACT emission limit has been expressed as 0.00044 lb hydrogen fluoride per MMBtu heat input, using EPA Reference Method 26A as the compliance test method. This is equivalent to 0.00042 lb/MMBtu, expressed as fluorides and using EPA Reference Method 13A as the compliance test method.

4. Cooling Towers 3 and 4 - PM and PM-10 Emissions

The induced mechanical-draft, wet cooling towers for Units 3 and 4 will be a source of particulate matter emissions since the drift from these units will contain both dissolved solids. The formation mechanism for this particulate matter is as follows: As a droplet that drifts from a wet cooling tower evaporates, the dissolved solids present in the droplet agglomerate into a single particle. The size of the resulting particle depends on the size of the droplet, the mass of the dissolved solids present in the droplet, and the density of the resulting particle.

Step 1 - Identify All Control Technologies

Two control options were identified for the proposed cooling towers:

- Replacement of wet cooling towers with air-cooled condensers; and
- Drift eliminators.

Air-cooled condensers are a design alternative to wet cooling towers. Air-cooled condensers achieve cooling of the circulating water through air-fin heat exchange. Because there is no contact between the water and the ambient air, and thus no opportunity for drift, there are zero emissions from air-cooled condensers.

Drift eliminators are located perpendicular to the air flow, and are designed to collect and remove from the air stream condensed water droplets by providing extensive surface area for droplets to gather and coalesce. Particulate matter emissions are thus minimized as drift is minimized.

Step 2 - Eliminate Technically Infeasible Options

No technically infeasible control options for cooling tower PM / PM-10 emissions were identified.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Air-cooled condensers have zero emissions and comprise the top control option. Drift eliminators are the second-ranked control option based on control effectiveness.

Step 4 - Evaluate Most Effective Controls and Document Results

In its initial permit application, the Permittee proposed as BACT the use of induced mechanical-draft, wet cooling towers with drift eliminators designed for total liquid drift of 0.004 percent of circulating water flow.

At the Department's request, the Permittee conducted a detailed economic impacts analysis of using air-cooled condensers in lieu of the wet cooling towers for Unit 3 and Unit 4. This analysis, using data compiled by U.S. EPA, showed that the incremental annualized cost of this control option for the TEP - SGS facility would be $10.4 million per year. The incremental PM emission reduction associated with this control option is approximately 108 tons per year, and the incremental cost effectiveness of approximately $100,000 per ton. This is considered to be an unreasonable economic impact. Thus, the Department agrees with the Permittee's proposal that high-efficiency drift eliminators represent BACT for the wet cooling towers.

Step 5 - Select BACT

As noted above, in its initial permit application, the Permittee proposed as BACT the use

of induced mechanical-draft, wet cooling towers with drift eliminators designed for total liquid drift of 0.004 percent of circulating water flow.

At the Department's request, the Permittee evaluated whether a higher level of control could be achieved with high-efficiency drift eliminators. Based on this evaluation, the Permittee adjusted its BACT proposal to reflect the use of drift eliminators with a vendor-guaranteed maximum total liquid drift of 0.0005 percent of circulating water flow rate. This is equivalent to the most stringent identified equipment specification for wet cooling towers, and the Department agrees that this proposal represents BACT.

It should be noted that emission testing is not feasible for wet cooling towers due to exhaust characteristics, so the BACT determination is expressed as an equipment specification rather than an emission limit.

5. Coal Preparation Plant - PM and PM-10 Emissions

Note that, for this analysis, consistent with NSPS subpart Y, the coal preparation plant includes all coal handling activities except for open storage piles. A summary of the BACT analysis for coal storage piles is presented in Section VI.A.6 herein.

The existing coal preparation plant will be modified, including the addition of several new components in parallel with the existing components, to accommodate the new Unit 3 and Unit 4. PM and PM-10 will be emitted from the new and modified equipment within the coal preparation plant. These emissions include fugitive dust from the various transfer points in the handling system.

For the current system, coal is delivered to the plant site by railcar. A rotary car dumper is used to unload the cars. Water mist and surfactant are sprayed during unloading. Coal from the dumper is collected in the unloading hopper beneath the dumper. Dust suppression is sprayed into the hopper above the coal level to control dust formation. Feeders supply coal to chutes, which in turn allow the coal to be routed to conveyors. Unloading conveyors transport the coal to the transfer tower and on to the lowering wells. The lowering wells are used to distribute the coal to the active storage piles. All transfer points are enclosed up to the storage piles. Dust suppression sprayers are provided at each conveyor discharge. Coal conveyor belts from the storage piles to the units are also covered and transfer points are equipped with dust collectors.

<u>Step 1 - Identify All Control Technologies</u>

The control technologies that can be used to control particulate matter emissions from coal handling operations are:

- Enclosures vented to fabric filter baghouses; and
- Using water sprays to wet down the dust to keep it from being emitted.

Step 2 - Eliminate Technically Infeasible Options

Both identified control options are technically feasible for the TEP - SGS coal preparation plant.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Enclosures with fabric filter baghouses comprise the top control option. For individual emission points at which enclosures are not feasible or reasonable, water spray is the second-ranked control option.

Step 4 - Evaluate Most Effective Controls and Document Results

The Permittee proposed as BACT the use of enclosures with fabric filter baghouses for all coal preparation plant emission points except for the rail unloading area and the emergency reclaim hopper. The cost of enclosing these operations would be unreasonable, given the very low emissions from these activities. The Permittee proposed as BACT the use of water sprays at the rail unloading area and the emergency reclaim hopper. The Department agrees that this technology selection represents BACT.

Step 5 - Select BACT

The Permittee initially proposed as BACT the use of fabric filter baghouses designed for exhaust particulate matter concentration not to exceed 0.02 grains per dry standard cubic foot (gr/dscf).

At the Department's request, the Permittee evaluated whether a higher level of control could be achieved with fabric filter baghouses. Based on this evaluation, the Permittee adjusted its BACT proposal to reflect the use of fabric filters designed to achieve exhaust particulate matter concentration not to exceed 0.01 gr/dscf. This is equivalent to the most stringent identified equipment specification for materials handling system fabric filter baghouses, and the Department agrees that this proposal represents BACT. In addition to this equipment specification, the Department is imposing a visible emissions opacity limitation of 10 percent for coal preparation plant fabric filter baghouses. This limitation will provide a more readily enforceable emission standard representing BACT, and will also ensure that the BACT emission limits for the TEP - SGS facility are as stringent as the most stringent limits identified at other comparable facilities. These requirements apply to all coal preparation plant emission points except for the rail unloading area and the emergency reclaim hopper.

For the rail unloading area and the emergency reclaim hopper, the Permittee proposed that use of water spray sufficient to ensure compliance with the NSPS opacity limit of 20 percent represents BACT. The Department agrees with this determination.

6. Coal Storage Piles - PM and PM-10 Emissions

One active coal storage pile and one inactive/emergency coal storage pile will be constructed to accommodate Unit 3 and Unit 4. PM and PM-10 will be emitted from the coal piles due to wind erosion and bulldozing maintenance of the piles.

Step 1 - Identify All Control Technologies

Three control technologies that can be applied to coal storage piles were identified:

- Enclosures vented to fabric filter baghouses;
- Chemical suppression; and
- Wet suppression.

Step 2 - Eliminate Technically Infeasible Options

No technically infeasible for the control of particulate matter emissions from coal piles were identified.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Enclosures with fabric filter baghouses are the top control option, at nearly 100 percent control efficiency. The second-ranked control option is chemical suppression. Wet suppression is the lowest-ranked control option.

For chemical suppression techniques, the achievable control efficiency ranges from approximately 80 percent to 99 percent, depending on the types of chemical suppressant used, the quantity applied, and the frequency of application. Based on the information gathered by the Permittee and submitted to the Department with the proposed BACT determination, lignin sulfonate (an amorphous polymeric substance similar to cellulose) and suppressant foams can achieve approximately 99 percent control for short-term storage. Some polymeric suppressants can achieve 99 percent control with less frequent application. Wet suppression with surfactant (a chemical that encapsulates and suspends moisture, enhancing and extending the effect of wet suppression) can achieve approximately 80 percent control with frequent application.

Step 4 - Evaluate Most Effective Controls and Document Results

The Permittee performed a detailed economic analysis of using an enclosure to control particulate matter emissions from the active coal pile at the TEP - SGS facility. Based on the results of that analysis, the capital cost of an enclosure would exceed $10 million. Even without considering any additional operating costs that may be associated with such an enclosure, the total annualized cost is approximately $1 million, and the incremental annualized cost (above the wet suppression with surfactant control option) is more than

$800,000. Based on total PM and PM-10 emission reductions of 125 tons per year and 26 tons per year, respectively, the total cost effectiveness is more than $8,000 per ton of PM reduction and $38,000 per ton of PM-10 reduction. Based on incremental PM and PM-10 emission reductions of 120 tons per year and 25 tons per year, respectively, the incremental cost effectiveness is approximately $7,000 per ton of PM reduction and $32,000 per ton of PM-10 reduction. This is economically unreasonable.

Because the emissions from the emergency coal pile are less than one-tenth those from the active coal pile, an enclosure would be even less cost effective for this pile. No detailed economic analysis was needed. The Permittee proposed the use of foam suppressant achieving 99 percent control of particulate matter emissions for the emergency coal pile. The Department agrees that this control option represents BACT.

The Permittee also performed a detailed economic analysis of using chemical suppressants for particulate matter emission control from the active coal pile. Based on information obtained from a dust suppressant vendor, the most cost-effective of these suppressants is water and lignin sulfonate, for approximately 99 percent control. Treatment with water and lignin sulfonate would cost approximately $0.05 per ton of coal, or approximately $200,000 per year. Based on total PM and PM-10 emission reductions of 124 tons per year and 26 tons per year, respectively, the total cost effectiveness is approximately $1,600 per ton of PM reduction and $8,000 per ton of PM-10 reduction. This is economically unreasonable.

For the above reasons, the Permittee proposed the use of wet suppression with surfactants for 80 percent overall control of PM and PM-10 emissions as BACT for the active coal storage pile. The Department agrees that this control option represents BACT.

Step 5 - Select BACT

The application of water and surfactant at the rail car dumper and along the coal transfer system represents BACT for the active coal storage piles. The application of a polymer suppressant represents BACT for the emergency storage piles. Compliance with an opacity limit of 40 percent also is required

7. Ash and Lime Handling - PM and PM-10 Emissions

A new fly ash handling system will be constructed for Unit 3 and Unit 4. This system will collect ash from the baghouse hoppers and pneumatically convey the ash to the fly ash silo. From the silo, the fly ash can be transferred back to the recycle feed bin in the spray dryer absorber or unloaded into trucks for disposal. The dry fly ash is fed from the silo through inlet chutes into each of four rotary unloaders. Inside the rotary unloaders, water from the bottom ash surge tank is sprayed into the fly ash to produce a dust free fly ash/water mixture. The mixture is discharged from the rotary unloaders through fixed chutes into the dump truck positioned below. The ash is then transported to the ash

burial area.

A new, open-loop lime handling system will be constructed for Unit 3 and Unit 4. This system will utilize combination pressure/vacuum pneumatic conveying. Lime is conveyed from the unloading station through a series of receivers and silos to the lime feed bins of each unit. A vent fan and fabric filter mounted on top of the silos vents conveying air from the silos to atmosphere. The lime is then transferred by conveyor pipe to the lime feed bin of either unit. The feed bin serves as a receiving vessel and supplies the lime to the lime preparation system. A fabric filter and exhauster mounted on the roof of the bin vents the transfer system conveying air.

PM and PM-10 will be emitted from the fly ash and lime handling systems.

Step 1 - Identify All Control Technologies

The control technologies that can be used to control particulate matter emissions from the fly ash and lime handling operations are:

- Enclosures vented to fabric filter baghouses; and
- Wetting of the material to reduce generation of dust.

Step 2 - Eliminate Technically Infeasible Options

Enclosures are technically feasible for the lime handling operations, but wet suppression is not, due to the form in which the raw material is recieved.

Both identified control options are technically feasible for the fly ash handling operations.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Enclosures with fabric filter baghouses comprise the top control option. For individual emission points at which enclosures are not feasible or reasonable, wetting is the second-ranked control option.

Step 4 - Evaluate Most Effective Controls and Document Results

The Permittee proposed as BACT the use of enclosures with fabric filter baghouses for all fly ash and lime handling system emission points except for the fly ash silo truck loading operation and the ash dump. The cost of enclosing these operations would be unreasonable, given the very low emissions from these activities. The Permittee proposed as BACT the use of wet suppression at the fly ash silo truck loading operation and the ash dump. The Department agrees that this technology selection represents BACT.

Step 5 - Select BACT

The Permittee initially proposed as BACT the use of fabric filter baghouses designed for exhaust particulate matter concentration not to exceed 0.02 grains per dry standard cubic foot (gr/dscf).

At the Department's request, the Permittee evaluated whether a higher level of control could be achieved with fabric filter baghouses. Based on this evaluation, the Permittee adjusted its BACT proposal to reflect the use of fabric filters designed to achieve exhaust particulate matter concentration not to exceed 0.01 gr/dscf. This is equivalent to the most stringent identified equipment specification for materials handling system fabric filter baghouses, and the Department agrees that this proposal represents BACT. In addition to this equipment specification, the Department is imposing a visible emissions opacity limitation of 10 percent for fly ash and lime handling system fabric filter baghouses. This limitation will provide a more readily enforceable emission standard representing BACT, and will also ensure that the BACT emission limits for the TEP - SGS facility are as stringent as the most stringent limits identified at other comparable facilities. These requirements apply to all fly ash and lime handling system emission points except for the fly ash silo truck loading operation and the ash dump.

For the fly ash silo truck loading operation and the ash dump, the Permittee proposed that use of wet suppression sufficient to ensure compliance with an opacity limit of 40 percent represents BACT. The Department agrees with this determination.

B. MAXIMUM ACHIEVABLE CONTROL TECHNOLOGY

As noted in Section IV.A herein, case-by-case Maximum Achievable Control Technology regulations under 40 CFR part 63, subpart B (incorporated at A.A.C. R18-2-302.D and implementing Title III of the Federal Clean Air Act Amendments of 1990) are applicable to the proposed Unit 3 and Unit 4 boilers at the TEP - SGS facility.

These regulations require that the Maximum Achievable Control Technology for hazardous air pollutants, or "MACT," must be applied to each of the new boilers.

Pursuant to 40 CFR 63.43(d), case-by-case MACT must meet the following requirements:

> "(1) The MACT emission limitation or MACT requirements recommended by the applicant and approved by the permitting authority shall not be less stringent than the emission control which is achieved in practice by the best controlled similar source, as determined by the permitting authority.
>
> (2) Based upon available information, ... the MACT emission limitation and control technology ... recommended by the applicant and approved by the

> permitting authority shall achieve the maximum degree of reduction in emissions of HAP which can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction."

As with BACT, an enforceable emission limit representing MACT must be included in the permit. This emission limit must be met continuously, and must be enforceable as a practical matter. In order for the emission limit to be enforceable as a practical matter, the permit must specify a reasonable compliance averaging time, consistent with established reference methods, and must include compliance verification procedures (i.e., monitoring requirements) designed to show compliance or non-compliance on a time period consistent with the applicable emission limit.

The selection of specific hazardous air pollutants to be covered under the MACT analysis was based upon a review of the pollutants expected to be emitted by the proposed boilers and upon MACT rulemakings undertaken by EPA for source categories with similar emission characteristics. Four classes of hazardous air pollutants were identified: mercury; other metals, such as arsenic and lead; acid gases, namely hydrogen fluoride and hydrogen chloride; and products of incomplete combustion, namely polychlorinated biphenyls (PCB), polychlorinated dibenzo-p-dioxins (PCDD), and polychlorinated dibenzofurans (PCDF).

Unlike BACT, there is little guidance establishing the procedure by which a case-by-case MACT determination is made. For the purposes of this analysis, the Department used a procedure similar to the top-down BACT analysis procedure outlined above.

Materials considered by the applicant and by the Department in identifying and evaluating available control options include the following:

> Entries in the RACT/BACT/ LAER Clearinghouse maintained by the U.S. EPA. This database is the most comprehensive and up-to-date listing of control technology determinations available.
> Information provided by pollution control equipment vendors.
> Information provided by industry representatives and by other State permitting authorities. This information is particularly valuable in clarifying or updating control technology information that has not yet been entered into the RACT/BACT/ LAER Clearinghouse.

The case-by-case MACT analysis and proposed MACT determinations for each of the four identified classes of hazardous air pollutants, for Units 3 and 4, are discussed in the following paragraphs:

1. Units 3 and 4 - Non-Mercury HAP Metals Emissions

The particulate matter emitted from Unit 3 and Unit 4 will include entrained metals that are contained in coal. These metals will include arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, and vanadium.

As noted in the BACT analysis for PM / PM-10 presented in Section VI.A.1 herein, the top control option is a fabric filter baghouse. The control options for non-mercury HAP metals are those identified in the BACT analysis for PM / PM-10, and the control efficiencies for non-mercury HAP metals correspond to the control efficiencies for PM and PM-10. Thus, the Department concludes that a fabric filter baghouse represents case-by-case MACT for non-mercury HAP metals.

As was also noted in the BACT analysis, the proposed BACT emission limits of 0.015 lb PM per MMBtu heat input and 0.055 lb PM-10 per MMBtu heat input are the most stringent limits identified for any coal-fired boiler of any type. Based on precedent established by U.S. EPA in establishing MACT standards for several categories of sources emitting non-mercury HAP metals, a PM emission limit is an effective surrogate for individual HAP metals emission limits and is an acceptable format for expressing the MACT standard. For example, U.S. EPA described its rationale for setting PM emission limits in the proposed iron & steel MACT standard:

> "For the proposed rule, we decided that it is not practical to establish individual standards for each specific type of metallic HAP that could be present in the various processes (e.g., separate standards for manganese emissions, separate standards for lead emissions, and so forth for each of the metals listed as HAP and potentially could be present). When released, each of the metallic HAP compounds behave as PM. As a result, strong correlations exist between air emissions of PM and emissions of the individual metallic HAP compounds. The control technologies used for the control of PM emissions achieve comparable levels of performance on metallic HAP emissions. Therefore, standards requiring good control of PM will also achieve good control of metallic HAP emissions. Therefore, we decided to establish standards for total PM as a surrogate pollutant for the individual types of metallic HAP. In addition, establishing separate standards for each individual type of metallic HAP would impose costly and significantly more complex compliance and monitoring requirements and achieve little, if any, HAP emissions reductions beyond what would be achieved using the surrogate pollutant approach based on total PM.."

For the above reasons, and in light of the precedent established by U.S. EPA in setting MACT standards using a surrogate pollutant, the Department determines that the BACT emission limits for PM and PM-10 will suffice as MACT standards for Unit 3 and Unit 4.

2. Units 3 and 4 - Acid Gas Emissions

As noted in the BACT analysis for fluorides in Section VI.A.3 herein, fluoride emissions from coal-fired boilers result from trace concentrations of fluoride-containing compounds in the fuel. These emissions occur primarily in the form of hydrogen fluoride. In addition, hydrogen chloride emissions will occur as a result of chloride-containing compounds present in the fuel. Both hydrogen fluoride and hydrogen chloride are HAP's subject to the case-by-case MACT requirement.

The control options and relative control effectiveness hierarchy is the same for hydrogen chloride and hydrogen fluoride as for fluorides. As noted in the fluorides BACT analysis, the top control option is a spray dry absorber in conjunction with a fabric filter baghouse. Thus, the Department concludes that this control equipment configuration represents case-by-case MACT for hydrogen fluoride and hydrogen chloride.

As discussed above in the case-by-case MACT analysis for non-mercury HAP metals, setting a MACT emission limit using a surrogate pollutant is acceptable in cases where the desired effect on emission control is achieved. The proposed BACT emission limit of 0.00044 lb hydrogen fluoride per MMBtu heat input is the most stringent limit identified for any coal-fired boiler of any type. For these reasons, the Department determines that the BACT emission limit for fluorides, expressed as hydrogen fluoride, will suffice as the MACT standard for acid gas emissions from Unit 3 and Unit 4.

3. Units 3 and 4 - Mercury Emissions

Mercury (Hg) is a naturally occurring constituent of soil and mineral deposits, including deposits of coal. When coal is burned, any trace quantities of mercury present is vaporized at the high temperatures within the furnace section of the boiler. Thus, in addition to the HAP metals discussed in Section VI.B.1 herein, Unit 3 and Unit 4 will emit mercury due to the presence of this metal in the fuel being burned. The case-by-case MACT analysis is treated separately from the other HAP metals because the behavior of mercury in the flue gas and the applicable control technologies for mercury emissions are not identical to those for other HAP metals.

Mercury is highly toxic, persistent, and bioaccumulates in food chains. Mercury emitted from electric utility steam generating units (and other sources) is transported through the atmosphere and eventually deposits onto land or water bodies. Once deposited, the chemical form of mercury can change (through a methylation process) into methylmercury which is a highly toxic, more bioavailable, form that biomagnifies in the aquatic food chain (e.g., fish).

According to the U.S. EPA "Mercury Study Report to Congress" of December 1997, most of the mercury currently entering U.S. water bodies and contaminating fish is the result of air emissions which, following atmospheric transport, deposit onto watersheds or directly to water bodies. Wastewater discharges also contribute to environmental

loadings, but to a much lesser degree than air emissions. Based on modeling conducted for the Report to Congress, the U.S. EPA estimates that roughly 60 percent of the total mercury deposited in the U.S. comes from U.S. anthropogenic air emission sources. In addition, the agency has identified coal-fired utilities as the largest emitters of mercury, accounting for more than 22 percent of the anthropogenic mercury emissions in the U.S. Based largely on the results of this study, U.S. EPA in December 2000 concluded that mercury is the HAP of greatest concern from utility coal-fired boilers. This was taken into account by the Department in reviewing the case-by-case MACT analysis submitted by the Permittee for Unit 3 and Unit 4 at the TEP - SGS facility.

Step 1 - Identify All Control Technologies

The capture of mercury by flue gas cleaning devices is dependent on the chemical and physical forms of mercury. There are three basic forms of mercury in the flue gas from coal combustion: elemental mercury (Hg°), ionic mercury [Hg(II)], and particulate-bound mercury [Hg(p)]. Both Hg° and Hg(II) are in a vapor phase at flue gas cleaning temperatures. Hg° is insoluble in water and cannot be captured in wet scrubbers. The predominate Hg(II) compounds in coal flue gas are weakly to strongly soluble and can be generally captured in wet FGD scrubbers. Both Hg° and Hg(II) can be adsorbed onto porous solids such as fly ash, activated carbon, or calcium-based acid gas sorbents for subsequent collection in a PM control device. Hg(II) is easier to adsorb than Hg°. Hg(p) is entrained in solids that can be readily captured in ESP's and fabric filter baghouses.

Flue gas cleaning technologies that are used on combustion sources use three basic methods to capture mercury: the capture of Hg(p) in PM control devices; the adsorption of Hg° and Hg(II) onto entrained sorbents for subsequent capture in PM control devices; and the solvation of Hg(II) in wet or semi-dry scrubbers. Factors that affect the speciation and capture of mercury in coal-fired combustion systems include the type and properties of coal, the combustion conditions, the type of flue gas cleaning technologies employed, and the temperatures at which the flue gas cleaning systems operate.

Identified mercury control options are as follows:[4]

- Electrostatic precipitator (ESP);
- Fabric filter baghouse
- Sorbent injection in conjunction with an ESP or a fabric filter baghouse;
- Wet scrubber

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[4] Selective Catalytic Reduction (SCR) has been indicated in some U.S. EPA publications as having the potential for achieving increased mercury control efficiency when used in conjunction with particulate matter control devices. Based on the Department's review, no original source data are available to confirm or quantify this effect. Thus, for the purposes of this analysis, the SCR that is proposed for use in achieving NO_X control at Unit 3 and Unit 4 is assumed to provide no incremental increase in achievable mercury emission control level.

Step 2 - Eliminate Technically Infeasible Options

As noted in the BACT analyses presented in Sections VI.A.1 and VI.A.3 herein, and in the case-by-case MACT analyses presented in Sections VI.B.1 and VI.B.2 herein, the selected air pollution control equipment for particulate matter, fluorides, non-mercury HAP metals, and acid gases from Unit 3 and Unit 4 is a spray dry absorber in conjunction with a fabric filter baghouse. Mercury emission control options that are not compatible with this configuration are not considered technically feasible for this analysis. The identified configurations that are eliminated on this basis are as follows:

- Stand-alone electrostatic precipitator
- Sorbent injection in conjunction with an ESP
- Stand-alone wet scrubber

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The identified, technically feasible air pollution control equipment configurations for mercury emissions are as follows:

- Spray dry absorber, using lime, in conjunction with a fabric filter baghouse; and
- Spray dry absorber, using lime and activated carbon, in conjunction with a fabric filter baghouse

Obviously, the only difference between these two control options is the presence or absence of activated carbon.

Step 4 - Evaluate Most Effective Controls and Document Results

The primary variable affecting mercury emissions is the quantity of mercury contained in the particular coal being burned. Western coals exhibit generally lower mercury content than eastern coals. However, even within the category of "Powder River Basin Coal," mercury content varies from 0.06 ppm for the Rochelle variety to 0.11 ppm for Thunder basin. The Lee Ranch coal proposed to be burned at the TEP - SGS Unit 3 and Unit 4 has a typical mercury content of 0.1 ppm. On an uncontrolled basis, assuming that all mercury in coal is emitted (i.e., none is retained in bottom ash), this equates to approximately 0.000011 pounds per million Btu heat input, or 420 pounds of mercury emitted per year from each boiler.

As noted previously, the speciation and capture of mercury in coal-fired combustion systems are dependent upon the type and properties of coal and the combustion conditions. Thus, in order to evaluate the effectiveness and the feasibility of adding activated carbon to the proposed (as BACT) air pollution control equipment configuration, the specific coal characteristics and combustion conditions at the TEP -

SGS Unit 3 and Unit 4 boilers must be evaluated.

Based on U.S. EPA's studies of mercury emissions from boilers burning sub-bituminous coal, most of the mercury is emitted as Hg°. A variable fraction, averaging approximately 25 percent, is oxidized to Hg(II) as the flue gases cool. This oxidized mercury reacts to form primarily mercuric chloride ($HgCl_2$) and smaller amounts of mercuric oxide (HgO), mercuric sulfate ($HgSO_4$), mercuric chloride ($HgCl_2$), and other mercury compounds. The Hg°, $HgCl_2$ and HgO are primarily in the vapor phase at flue gas cleaning temperatures. Other species are primarily in the solid phase.

$HgCl_2$ is water-soluble and reacts readily with alkali metal oxides in an acid-base reaction. Therefore, the spray dry absorber / fabric filter baghouse configuration can be expected to capture mercury emissions in the form of $HgCl_2$ with relatively high efficiency.

Hg° and HgO are relatively insoluble. Nonetheless, some relatively small fraction of these vapors will be captured by the baseline control equipment configuration. This capture mechanism is primarily due to adsorption on the carbonaceous fly ash that forms a "cake" on the fabric filter bags, with some additional capture due to adsorption on the calcium-based (lime) sorbent.

The remaining species, which are present in the boiler flue gases primarily in the solid phase, also can be expected to be captured with nearly 100 percent efficiency by the spray dry absorber / fabric filter baghouse configuration.

The Permittee has proposed as MACT a mercury emission limit of 0.0000069 lb/MMBtu heat input. This represents an overall mercury control efficiency of 39 percent, or mercury emissions of 254 pounds per year per unit. Based on the Department's review of available U.S. EPA data, this level appears achievable with the proposed control device configuration.

Activated carbon injection, used in conjunction with effective particulate matter control equipment, has been shown to achieve 90 percent control of mercury emissions for some types of sources, especially municipal waste combustors. However, the success of activated carbon injection systems for mercury removal with municipal waste combustors has not been realized in tests for coal-fired facilities. The reasons for this lack of success are not known, but are believed to include the relatively low concentrations of mercury in flue gas and the relatively high concentrations of competing species occupying the active sites on carbon particles. Extensive research is ongoing into the investigation and development of sorbents that are more effective in the removal of mercury from coal-fired combustion flue gases. For the purposes of this analysis, it is assumed that the top control option, including the baseline control equipment configuration with activated carbon injection, will achieve an overall mercury control efficiency of 80 percent. This would result in mercury emissions of 84 pounds per year per unit, or an incremental

reduction of 170 pounds per year relative to the baseline control option.

The Permittee estimated, based on an unsubstantiated cost estimate for a hypothical but apparently similar facility, that the cost of adding an activated carbon injection system to the baseline control equipment configuration at TEP - SGS is approximately $3.2 million per year per unit.

To verify the information provided in the Permittee's case-by-case MACT analysis, the Department reviewed extensive mercury emission control and cost data generated by U.S. EPA. Based on these data, the cost of adding activated carbon injection system to the baseline control equipment configuration at TEP - SGS is likely between $2 million and $4 million per year per unit. Assuming a required injection rate of 1 pound per million actual cubic feet of exhaust gas, the cost of activated carbon is approximately $400,000 per year per unit. This is consistent with the Permittee's incremental control cost estimate.

Using the above values, the incremental cost effectiveness of using activated carbon injection for mercury control is approximately $20,000 per pound of mercury removed. Compared to the cost-effectiveness values established as precedent in prior BACT determinations for criteria pollutants, this appears to be economically unreasonable, even without taking into consideration any solid waste issues. However, because the it had not previously made a cost-effectiveness determination for mercury, the Department undertook a review of U.S. EPA MACT rulemaking efforts for mercury cost-effectiveness precedent. The Department identified that, in the MACT rulemaking for hazardous waste combustors (see preamble to 40 CFR 63 subpart EEE, 64 FR 52828), U.S. EPA determined that a cost effectiveness of $9 million per ton was unreasonable for mercury control. The projected cost effectiveness for activated carbon injection at the proposed TEP - SGS Unit 3 and Unit 4 is well in excess of $30 million per ton of reduction. Thus, activated carbon injection is determined to be economically unreasonable.

Step 5 - Select MACT

As noted above, the Permittee has proposed as MACT the use of a spray dry absorber and a fabric filter baghouse achieving a mercury emission limit of 0.0000069 lb/MMBtu heat input. The only identified control option that is more effective than the proposed control option was determined to be economically unreasonable. Unlike BACT, one additional step is necessary before the MACT determination can be approved. The MACT determination cannot be less stringent than the emission control which is achieved in practice by the best controlled similar source. The proposed MACT determination is equivalent to 39 percent control of mercury emissions. Based on a review of U.S. EPA data, no coal-fired boiler is achieving a mercury emission control that is more stringent than this 39 percent control efficiency. Therefore, the Department agrees that the applicant's proposal represents MACT. The draft permit requires that compliance be

demonstrated by annual stack testing using EPA Reference Method 29.

VII. AIR QUALITY IMPACT ANALYSIS

A. General

As noted in Section IV.A herein, PSD regulations under Title I of the Federal Clean Air Act and R18-2-406.A , and the impacts analysis requirements under those regulations, are applicable to the proposed major modification for emissions of PM_{10}, CO, and lead. The impacts analysis is designed to protect the National Ambient Air Quality Standards (NAAQS) and the PSD increments. As a supplement to the permit application, the Permittee provided an extensive document titled "Air Quality Impact Analysis for the Springerville Units 3 and 4 Project," dated August 2001, which included all air quality modeling files on electronic media.

The NAAQS are maximum concentration "ceilings" measured in terms of the total concentration of a pollutant in the atmosphere. For a new or modified source, compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the background concentrations, the estimated ambient impacts of existing sources of air pollution, and the estimated ambient impacts of the applicant's proposed emissions. A PSD increment, on the other hand, is the maximum increase in ambient concentration that is allowed to occur above a baseline concentration for a pollutant. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment.

In addition to the above analyses required for pollutants that triggered PSD review requirements, an abbreviated analysis of air quality impacts also was required by the Department for emissions of NO_x and SO_2. As discussed in detail in Section IV.B herein, the proposed modification will result in zero net emissions increase for NO_x and SO_2. This zero net emissions increase will be assured by inclusion of emission caps, along with stringent monitoring requirements, in the proposed permit revision. The emission caps, in turn, will require that emissions from the existing Units 1 and 2 be decreased as necessary to offset any emissions that may occur from Units 3 and 4. The abbreviated analysis for NO_x and SO_2 was required by the Department in order to that the emissions decreases from Units 1 and 2 will have "approximately the same qualitative significance for public health and welfare as that attributed to the increase" from Units 3 and 4. The PSD regulation (at R18-2-101.72.f.iii) requires that this criterion is met in order for emissions increases and emissions decreases to be compared on a 1-for-1 basis in determining the net emissions increase from a particular project.

B. Modeling Methodology

1. Comparison with PSD and NAAQS Values

Modeling was performed to determine if the source would meet the PSD Class I and Class II increments for SO_2 and PM_{10} and the NAAQS for SO_2, PM_{10}, CO, and lead. All

modeling was conducted conforming to guidance issued by the Department, the U.S. EPA, and the Federal Land Manager (FLM). Tables VII-B-1 through VII –B-3 list the SGS sources as modeled. More detailed information about the sources can be obtained from the Air Quality modeling report (ENSR, Aug 2001).

Table VII-B-1 Source Emissions and Stack Parameters for SGS Point Sources

Source ID	UTM Easting (m)	UTM Northing (m)	Elev (m)	NOX (tpy)	CO g/s	SO_2 g/s	PM_{10} g/s	Stack Ht (m)	Temp (K)	Velocity (m/s)	Diam (m)
UNIT1	668771.6	3798731	2128	NA[a]	158.8	348[b]	37.296	152.4	339	21.3	6.096
UNIT2	668682.5	3798731	2128	NA[a]		348[b]	37.296	152.4	339	21.3	6.096
UNIT3n4	668554.5	3798731	2128	6167	158.8	635	58.212	152.4	339	21.3	8.621
EMGEN12	668799.9	3798560	2128	4	.5	.3	0.1	4	293	0.01	0.01
EMGEN34	668625.8	3798567	2128	4	.5	.3	0.1	4	293	0.01	0.01
FIREPUMP	668984.9	3798772	2128	NA	NA	NA	0.2	4	293	0.01	0.01
Cooling[c] Tower 1											
1CT1	669328.5	3798591	2130.4				0.315	27.58	293	7.53	10.97
1CT10	669265.1	3798527	2130				0.315	27.58	293	7.53	10.97
1CT11	669258	3798520	2130.9				0.315	27.58	293	7.53	10.97
1CT12	669250.9	3798513	2131				0.315	27.58	293	7.53	10.97
1CT13	669243.9	3798505	2131				0.315	27.58	293	7.53	10.97
1CT2	669321.5	3798584	2130.1				0.315	27.58	293	7.53	10.97
1CT3	669314.4	3798577	2129.9				0.315	27.58	293	7.53	10.97
1CT4	669307.4	3798570	2129.9				0.315	27.58	293	7.53	10.97
1CT5	669300.3	3798562	2129.9				0.315	27.58	293	7.53	10.97
1CT6	669293.3	3798555	2129.9				0.315	27.58	293	7.53	10.97
1CT7	669286.2	3798548	2130				0.315	27.58	293	7.53	10.97
1CT8	669279.2	3798541	2130				0.315	27.58	293	7.53	10.97
1CT9	669272.1	3798534	2130				0.315	27.58	293	7.53	10.97
Cooling[c] Tower 2											
2CT1	669536.1	3798576	2132				0.315	27.58	293	7.53	10.97
2CT10	669472.6	3798512	2132				0.315	27.58	293	7.53	10.97
2CT11	669465.6	3798505	2132				0.315	27.58	293	7.53	10.97
2CT12	669458.5	3798498	2132				0.315	27.58	293	7.53	10.97
2CT13	669543.2	3798583	2132				0.315	27.58	293	7.53	10.97
2CT2	669529	3798569	2132				0.315	27.58	293	7.53	10.97
2CT3	669522	3798562	2132				0.315	27.58	293	7.53	10.97
2CT4	669514.9	3798555	2131.3				0.315	27.58	293	7.53	10.97
2CT5	669507.9	3798547	2131.3				0.315	27.58	293	7.53	10.97
2CT6	669500.8	3798540	2131.3				0.315	27.58	293	7.53	10.97
2CT7	669493.8	3798533	2131.2				0.315	27.58	293	7.53	10.97
2CT8	669486.7	3798526	2131.2				0.315	27.58	293	7.53	10.97
2CT9	669479.7	3798519	2132				0.315	27.58	293	7.53	10.97
Cooling[d] Tower 3											
3CT1	668268.1	3798682	2128				0.0358	27.58	293	7.53	10.97
3CT10	668205.1	3798619	2127				0.0358	27.58	293	7.53	10.97
3CT11	668198.1	3798612	2127				0.0358	27.58	293	7.53	10.97
3CT12	668191.1	3798605	2127				0.0358	27.58	293	7.53	10.97
3CT13	668184.1	3798598	2127				0.0358	27.58	293	7.53	10.97
3CT2	668261.1	3798675	2128				0.0358	27.58	293	7.53	10.97

Source ID	UTM Easting (m)	UTM Northing (m)	Elev (m)	NOX (tpy)	CO g/s	SO_2 g/s	PM_{10} g/s	Stack Ht (m)	Temp (K)	Velocity (m/s)	Diam (m)
3CT3	668254.1	3798668	2128				0.0358	27.58	293	7.53	10.97
3CT4	668247.1	3798661	2127				0.0358	27.58	293	7.53	10.97
3CT5	668240.1	3798654	2127				0.0358	27.58	293	7.53	10.97
3CT6	668233.1	3798647	2127				0.0358	27.58	293	7.53	10.97
3CT7	668226.1	3798640	2127				0.0358	27.58	293	7.53	10.97
3CT8	668219.1	3798633	2127				0.0358	27.58	293	7.53	10.97
3CT9	668212.1	3798626	2127				0.0358	27.58	293	7.53	10.97
Cooling [d] Tower 4											
4CT1	668097.1	3798511	2121				0.0358	27.58	293	7.53	10.97
4CT10	668034.1	3798448	2126				0.0358	27.58	293	7.53	10.97
4CT11	668027.1	3798441	2126				0.0358	27.58	293	7.53	10.97
4CT12	668020.1	3798434	2127				0.0358	27.58	293	7.53	10.97
4CT13	668013.1	3798427	2127				0.0358	27.58	293	7.53	10.97
4CT2	668090.1	3798504	2121				0.0358	27.58	293	7.53	10.97
4CT3	668083.1	3798497	2123				0.0358	27.58	293	7.53	10.97
4CT4	668076.1	3798490	2123				0.0358	27.58	293	7.53	10.97
4CT5	668069.1	3798483	2124				0.0358	27.58	293	7.53	10.97
4CT6	668062.1	3798476	2124				0.0358	27.58	293	7.53	10.97
4CT7	668055.1	3798469	2125				0.0358	27.58	293	7.53	10.97
4CT8	668048.1	3798462	2125				0.0358	27.58	293	7.53	10.97
4CT9	668041.1	3798455	2126				0.0358	27.58	293	7.53	10.97

[A] *NOX emissions are netted out/ no increase in NOX emissions*

[b] *SO2 emissions are netted out/ no increase in hourly SO2 emission cap of 8,448 lbs/hr; modeling was done with numerous cases with these maximum short term limits tp demonstrate compliance.*

c Cooling tower emissions for existing towers 1 and 2 are based on Drift of .005%

d Cooling tower emissions for new towers 3 and 4 are based on Drift of .0005%

Table VII-B-2 Source Emissions and Stack Parameters for SGS Volume Sources (PM_{10} modeling only)

Source ID	*Description*	*X-coord (m)*	*Y-Coord (m)*	*Elev (m)*	*Emissions g/s*	*Stack Ht (m)*	*Sigma Y (m)*	*Sigma Z (m)*
E1	Rotary Car Dumper	668792.9	3798957	2127.2	0.01083	6	2.8	2.8
E2	Unloading Conveyors	668793.1	3798979	2127.2	0.00092	6	2.8	2.8
E3	Unloading Transfers	668794.5	3799139	2126.8	0.00092	17.7	2.8	2.8
E4	Unloading Transfers	668794.5	3799139	2126.8	0.00092	17.7	2.8	2.8
E5	Stackout Conveyor	668640.6	3799138	2126.1	0.00092	9.1	2.8	2.8
E6	Emerg Stackout Conveyor	668640.6	3799138	2126.1	0.00541	9.1	2.8	2.8
E7	Stackout Conveyor	668640.6	3799138	2126.1	0.00092	9.1	2.8	2.8
E8	Stackout Tower	668640.6	3799138	2126.1	0.00541	40.5	2.8	2.8
E9	Lowering wells 1-3	668640.7	3799174	2126.2	0.00541	6	2.8	2.8
E11	Stackout Conveyor	668568.9	3799135	2125.8	0.00541	31.7	2.8	2.8
E12	Telescopic Shute	668568.9	3799135	2125.8	0.00541	9.1	2.8	2.8
E15	Crusher Feed Conveyor	668639.8	3799030	2127	0.00036	6	2.8	2.8
E16	Emerg Storage reclaim	668568.9	3799135	2125.8	0.0018	6	2.8	2.8
E18	Emerg Reclaim Conveyor	668603	3799025	2126.8	0.00036	6	2.8	2.8
E19	Secondary Crusher	668638.8	3798934	2128.2	0.00036	27.4	2.8	2.8
E20	Secondary Crusher Coll.	668638.8	3798934	2128.2	0.00036	27.4	2.8	2.8
E21	Crusher Discharge Conv.	668638.8	3798934	2128.2	0.00036	9.1	2.8	2.8
E22	Crusher Discharge Conv.	668638.8	3798934	2128.2	0.00036	9.1	2.8	2.8

Source ID	*Description*	*X-coord (m)*	*Y-Coord (m)*	*Elev (m)*	*Emissions g/s*	*Stack Ht (m)*	*Sigma Y (m)*	*Sigma Z (m)*
E23	Sampler Enclosure	668731	3798934	2129	0.00036	17.1	2.8	2.8
E24	Sampler Enclosure	668731	3798934	2129	0.00036	17.1	2.8	2.8
E32	Ash Silos Truck Load	668683	3798813	2128	0.0289	6	2.8	2.8
E25	Silo Feed Conveyor	668731	3798606	2128	0.00036	9.1	2.8	2.8
E26	Silo Feed Conveyor	668731	3798606	2128	0.00036	9.1	2.8	2.8
E27	Silo Feed Tower	668731	3798606	2128	0.00036	68	2.8	2.8
E28	Silo Feed Tower	668731	3798606	2128	0.00036	68	2.8	2.8
E29	Silo Feed Tower	668731	3798606	2128	0.00036	68	2.8	2.8
E30	Tripper Conveyor	668731	3798606	2128	0.00036	51.8	2.8	2.8
E31	Tripper Conveyor	668731	3798606	2128	0.00036	51.8	2.8	2.8
E43	Lme Unloading	668920	3798606	2128	0.0346	27.3	2.8	2.8
E46	Water Treatment Vent	668920	3798606	2128	0.0028	6	2.8	2.8
E48	Lime Feed Bin	668920	3798606	2128	0.0166	15.2	2.8	2.8
E49	Soda ash silo	668920	3798606	2128	0.0554	28.5	2.8	2.8
1	New Rotary Car Dumper	668858	3799332	2127	0.01083	9.1	2.8	2.8
2	Transfer Tower #1	668717	3799337	2127	0.001	9.1	2.8	2.8
3	Transfer Tower #2	668557	3799442	2127	0.001	9.1	2.8	2.8
4	Emerg Stackout Pile	668576	3799332	2127	0.03	10	2.8	2.8
5A	Active Pile stacking	668398	3799073	2124	0.03	10	2.8	2.8
5B	Active Pile reclaim	668398	3799073	2124	0.03	6	2.8	2.8
6	Transfer Tower #3	668274	3799002	2124	0.001	9.1	2.8	2.8
7	Emerg Reclaim Hopper	668343	3799048	2124	0.007	6	2.8	2.8
8	New Crusher Tower	668593	3798989	2127	0.001	51.8	2.8	2.8
9	Transfer Tower #4	668731	3798983	2127	0.001	9.1	2.8	2.8
10	Transfer Tower #5	668591	3798927	2127	0.001	9.1	2.8	2.8
11	Existing Crusher Tower	668639	3798934	2128	0.001	9.1	2.8	2.8
12	Transfer Tower #6	668611	3798781	2127	0.001	9.1	2.8	2.8
14A	Units 3-4 Ash Silo	668544	3798789	2128	0.00882	33.5	2.8	2.8
14B	Units 3-4 Ash Silo	668544	3798771	2128	0.00882	33.5	2.8	2.8
15A	Units 3-4 Lime Silo	668486	3798683	2128	0.08316	15.2	2.8	2.8
15B	Units 3-4 Lime Silo	668486	3798671	2128	0.08316	15.2	2.8	2.8
16	Lime Rail Unload	668471	3798679	2128	0.08316	9.1	2.8	2.8
17	Units 3-4 Silo Tripper	668556	3798542	2129	0.001	51.8	2.8	2.8
18	Existing Transfer Tower	668731	3798934	2127	0.001	9.1	2.8	2.8
19	Transfer Tower #7	668618	3798542	2129	0.001	9.1	2.8	2.8
20A	Units 3-4 Ash Silo Trk	668544	3798807	2128	0.02886	6	2.8	2.8
21	Units 3&4 Lime Silo/Water	668920	3798606	2128	0.0693	33.5	2.8	2.8
34	Units 3&4 Ash Silo/Water	668920	3798606	2128	0.02772	28.5	2.8	2.8
101-353	Ash Haul Road [c]				0.0193	2	14.2	3

[c] *Haul road modeled 12 hours a day; total of 255 sources *.0193 gs/s * 12 hrs day, = 469 lbs/day*

Table VII-B-3 Source Emissions and Stack Parameters for SGS Area Sources (PM_{10} modeling only)

Source Id	*Description*	*X-Coord (m)*	*Y-coord (m)*	*Elev (m)*	*Emissions g/s/m^2*	*Total Emissions g/s*	*Release Ht m*
Active12	Active Pile 1 & 2	668591	3799101	2126	1.01E-06	0.027	10
Emerg12	Emergency Storage 1 & 2	668488	3799172	2126	2.66E-08	3.12E-04	6
Active34	Active Pile 3&4	668520	3799252	2125	1.01E-06	0.027	10
Emerg34	Emergency Storage 3 & 4	668321	3799212	2124	2.66E-08	3.12E-04	6

2. NAAQS and PSD Increment Inventory

Three major sources were modeled as part of the NAAQS inventory: the Coronado Salt River Project, Sterling Brothers, Stone Forest Industries These sources were included in the PM_{10} PSD increment analyses and the full PM_{10} NAAQS impact analysis. Only the Coronado Salt River Project was included for the multi-source SO_2 modeling analyses, as the other source groups have very low SO_2 emissions. The emissions, stack parameters, and locations for these sources are shown in Table VII-B-4.

Table VII-B-4 Major Source Emissions and Stack Parameters

Source Description	*UTME (m)*	*UTMN (m)*	*Distance to SGS (km)*	*Elev. (ft)*	*Emissions (g/s)*		*Height (m)*	*Temp (k)*	*Velocity (m/s)*	*Diameter (m)*
Salt River Project					PM_{10}	SO_2				
CORON1	658500	3827400	30.5	1767	0.44		7.6	697	32.6	0.3
CORON2	658500	3827400	30.5	1767	15.51	644	152.4	380	27	5.8
CORON3	658500	3827400	30.5	1767	8.5		27.6	293	7.5	10.97
Sterling Brothers										
SB1	695000	3800000	26.1	2119.5	0.18	0	6	293	1.5	1
Stone Forest										
SF1_12	657800	3774500	26.8	2184.6	2.84	0.024	7.6	697	32.6	0.3
SF_13	657800	3774500	26.8	2184.6	1.53		14	411	214	10.1
SF14_16	657800	3774500	26.8	2184.6	0.18		15.2	293	88.7	3.8

3. Computer Model Used

The Industrial Source Complex Short Term Model (ISCST3, version 00101) was used for modeling those pollutants primarily emitted from the tall stacks at SGS. When assessing the impacts from $PM_{10,}$ the ISCPRIME (version 98069) model was used, due to its revised building downwash algorithims. The PM10 impacts are at times significantly effected by building downwash, and the ISCPRIME model has been specifically developed to more effectively predict the impacts from downwash. The model is

scheduled to become EPA's recommended model for these applications in the very near future, but until then can be approved on a case-by-case basis only. The model was approved for this application by ADEQ and EPA before final modeling was done. During the application, a computer irregularity was discovered in the ISCPRIME model when adding up volume sources. Therefore, for PM_{10} modeling, all point sources were modeled with the ISCPRIME model, and all volume and area sources were modeled with ISCST3. The results were than added together with an application program provided by the applicant. The department duplicated the results of this postprocessor with another previously utilized post-processing program. For modeling Class I impacts greater than 50 kilometers away, the applicant used the appropriate model CALPUFF, as discussed in the modeling protocol and the Air Quality Modeling document (ENSR, 2001).

4. Receptor Grid

For purposes of demonstrating compliance with the PSD increment, the NAAQS and AAAQG's, a receptor grid was created with sufficient density as to capture the maximum model-predicted impact within the surrounding ambient air (inclusive of process area where applicable). Receptor elevations were derived from USGS Digital Elevation Model (DEM) data except for those areas where DEM data was not available. In those areas, terrain data was reduced manually from USGS maps.

5. Meteorological Data

Two sets of meteorological data were used in the analyses. For those pollutants whose emissions are primarily emitted from the tall stacks at the SGS, one year's data from surface observations of winds and temperature obtained from the on-site meteorological 60 meter "Weather Station" site at the facility were used in accordance with the "Air Quality Modeling Protocol." The last complete year of data of adequate reliability was 1993, and so this data was used. Pasquill-Gifford (PG) stability classes were calculated using the standard deviation of the horizontal wind direction (sigma theta) in combination with observed wind speed and time of day. When modeling the impacts from PM10, where much the impact derives from low-level fugitive sources, the latest 5 years of meteorological data collected at the on-site 10-meter tower next to the coal-yard was used. Again, stability classes were calculated using sigma theta. Surface observations were combined with concurrent twice-daily mixing height observations from the nearest National Weather Service upper air station (Albuquerque, New Mexico), using EPA's PCRAMMET meteorological data preprocessor to create the hourly meteorological data set required by ISCST3 and ISCPRIME for modeling.

6. Downwash and Good Engineering Practice

The building wake option was invoked in ISCST3. EPA's Building Profile Input Program (BPIP) was utilized to determine building downwash scenarios. There are numerous buildings on the facility that will produce building wake effects. A modeling

version of BPIP, BPIP-PRIME was used to determine the calculate the building downwash information when modeling with ISCPRIME. All the stacks are subject to downwash. The building locations and GEP analysis were independently confirmed.

7. Background Concentrations

The Department approved the use of air quality data collected at the SGS maintained by TEP and annually audited by ADEQ. The background 24-hour PM_{10} concentration was taken as the average maximum 24-hour monitored value from the nearby coal-yard monitoring site for the last three years (1998-2000), a concentration of 35.3. g/m^3 .The annual background PM_{10} concentration likewise was the average of the last 3 years, 10.6 g/m^3. The background SO_2 concentrations were taken from the TEP Coyote Hills monitoring site, located approximately 10 miles south-southwest of SGS. These values, the highest monitored concentrations for the period 1996-2000 are listed in Table VII-B-5.

Table VII-B-5 Ambient Background Monitored Air Quality Data

Pollutant	Averaging Period	Background Concentration	NAAQS
PM10	24-hour	35.3	150
	Annual	10.6	50
SO2	3-hour	134	1300
	24-hour	29	365

8. Impact Area

The applicant showed analysis that for the pollutants applicable to model for PSD, (CO, PM_{10}, and lead), only PM_{10} had predicted maximum concentrations greater than the significant impact level (SIL) for any of the relevant averaging periods. The maximum distance of the significant impact area for PM_{10} is approximately one kilometer from the center of SGS. The applicant did revised modeling for PM_{10} with a receptor grid extending out to include a buffer area more than 2 kilometers from the edge of the defined “process area” in all directions. The department agrees that this is more than adequate. Because predicted modeled impacts were all lower than the SIL for CO or lead, no additional modeling was performed for these pollutants. For the requested modeling analysis of SO_2 impacts, the applicant used a grid extending out to more than 20 kilometers from the SGS. Again, the department feels this is adequate.

C. Modeling Results

1. Comparison of SGS Impacts with NAAQS and PSD Increments

Model-predicted maximum offsite concentrations in the Class II area surrounding the plant are presented in Tables VII-C-1 and VII-C-2. Concentrations are compared to both the NAAQS and the maximum allowable incremental increase in air pollutant concentrations occurring over the baseline concentration in Class I and Class II attainment areas.

As shown in Table VII-C-1, for all pollutants, total maximum model-predicted concentrations are less than the NAAQS. Similarly, as shown in Table VII-C-2, for all pollutants, maximum model-predicted model concentrations are less than the Class II PSD increments.

The maximum impact for the 24-hour PSD Class II increment is 23.18 ug/m^3, located at the process area boundary near the ash dump site, located approximately 6 kilometers west of the main facility. Fugitive sources are the main contributor to these concentrations. There are also areas near the main facility where predicted concentrations of approximately 20 ug/m^3 occur, and are largely caused by impacts from nearby cooling towers. These values are about 66 percent of the PSD Class II 24-hour increment of 30 ug/m^3.

In addition, the department had requested modeling analyses for 5 sensitive receptors in the area. The maximum modeled impacts at these areas, as listed in Table VII-C-3 are also much less than the PSD Class II increment levels.

As agreed upon with preliminary discussions with the National Park Service and the Forest Service (FLM for the project), three Class I areas were analyzed: Gila Wilderness Area, the Petrified Forest National Park, and Mount Baldy Wilderness Area. Results , listed in Table VII-C-4, again show all impacts to be less than the Class I PSD increment levels when modeling with ISCST3 and/or CALPUFF.

Table VII-C-1 Maximum Air Quality Impacts Due to SGS Sources

Pollutant	Averaging Period	Maximum Project Impact (Fg/m^3)	Significant Impact Level (Fg/m^3)	Background (Fg/m^3)	Maximum Concentration* (Fg/m^3)	NAAQS (Fg/m^3)	Location UTME (m)	Location UTMN (m)	Distance from SGS (km)
NO_2	Annual	0.7	1	NA	--	100	679,598	3,784,706	17.85
CO	1-hour	114	2000	NA	--	40,000	684,598	3,785,706	20.67
	8-hour	32	500	NA	--	10,000	684,598	3,786,906	19.93
SO_2	3-hour	389.6	25	134	531.3	1,300	668,896	3,797,551	1.23
	24-hour	56.6	5	29	89.9	365	669,196	3,797,555	1.34
PM_{10}	24-hour	23.2	5	35.3	58.48	150	661,915	3,797,900	6.69
	Annual	4.92	1	10.6	15.52	50	668,489	3,799,795	1.07
Lead	Quarterly	0.0004	--	0.0044	0.435	1.5	672,598	3,797,956	4.12

Table VII-C-2 Class II Increment Analysis

Class	Pollutant	Averaging Period	PSD Increment (Fg/m^3)	Modeled Impact (Fg/m^3)	% of Increment	UTMX (M)	UTMY (M)
II	SO_2	3-hour	512	389.6	76	668896	3797551
II	SO_2	24-hour	91	56.2	62	669196	3797555
II	PM_{10}	24-hour	30	23.2	77	661915	3797900
II	PM_{10}	Annual	17	4.92	29	668489	3799795

Table VII-C-3 Class II Increment Analysis

Class	Pollutant	Averaging Period	PSD Increment (Fg/m^3)	Modeled Impact (Fg/m^3)	% of Increment	UTMX (M)	UTMY (M)
II	SO_2	3-hour	512	389.6	76	668896	3797551
II	SO_2	24-hour	91	56.2	62	669196	3797555
II	PM_{10}	24-hour	30	23.2	77	661915	3797900
II	PM_{10}	Annual	17	4.92	29	668489	3799795

Table VII –B4 Results of Modeling at Sensitive Receptors for SGS (Concentrations in Fg/m3)

Location	*3-hr-SO2*	*24-hr SO2*	*24-hr PM10*	*Annual PM10*
Lyman Lake	47.6	6.2	0.8	0.04
Little Colorado Fishery	40.5	7.9	0.6	0.04
Becker Lake Fishery	31.5	4.3	0.6	0.04
Casa Malpais	38.3	7.4	0.7	0.04
Coronado Byway	51.5	6.9	0.8	0.04
PSD Class II Increment	512	91	30	17

Table VII-C-4 PSD Class I Increment Analysis for SGS

Location	*Pollutant*	*Averaging Period*	*ISCST3 Results*	*CALPUFF Results*	*PSD Class I Increment*
GILA WA	SO2	3-hr	N/A	10.9	25
		24-hr	N/A	3.0	5
		Annual	N/A	0.28	2
	PM10	24-hr	N/A	0.59	8
		Annual	N/A	0.05	4
Petrified Forest	SO2	3-hr	N/A	12.4	25
		24-hr	N/A	3.5	5
		Annual	N/A	0.46	2
	PM10	24-hr	N/A	0.55	8
		Annual	N/A	0.07	4
Mt Baldy	SO2	3-hr	16.4	22.5	25
		24-hr	2.8	3.3	5
		Annual	0.14	0.18	2
	PM10	24-hr	0.35	0.69	8
		Annual	0.02	0.04	4

2. Comparison with AAAQGs

Modeling was performed to determine if the source would meet the Arizona Ambient Air Quality Guidelines (AAAQG) for 24 air toxics whose total emissions were greater than 500 pounds per year. . The applicant modeled emissions of these chemicals from Units 1-4. This modeling used the same dispersion model (ISCPRIME , meteorological data, building downwash, and basic model parameters and assumptions used in the criteria pollutant modeling. Concentrations were modeled for the process area and ambient air, according to Department policy.

Table VII-C-5 presents the results of both short term and the annual AAAQG analysis. The modeling demonstrates that maximum predicted concentrations of all air toxics are less than all AAAQG values. The maximum level reached is for the 1-hour AAAQG for flourine, where about 20 percent of the AAAQG is reached. The maximum of any annual AAAQG is for nickel, where the value is about 2 percent of the level.

Table VII-C-5 SGS Units 1-4 Comparison to AAAQG for Compounds with Emissions Greater than 500 lbs per year

Compounds	*AAAQG (ug/m^3)*			*Emission rate (Units 1-4)*		*Modeled Impact(ug/m^3)*		
	1hr	24-hr	Annual	lb/hr	lb/yr	1hr	24-hr	Annual
1,1,2-trichlorethane	8.70E+01	2.30E+01	6.20E-02	7.71E-02	6.75E+02	7.801E-03	7.869E-04	4.733E-05
Acetaldehyde	6.30E+02	1.70E+02	4.50E-01	1.11E-01	9.70E+02	1.123E-02	1.133E-03	6.802E-05
Ammonia	2.30E+02	1.40E+02	NA	4.24E+01	3.71E+05	3.85E+00	3.72E-01	2.15E-02
BIS(2-ethyl) (DEHP)	1.50E+02	4.00E+01	2.50E-01	6.72E-02	5.89E+02	6.799E-03	6.858E-04	4.130E-05
Bromoform	1.50E+02	4.00E+01	9.00E-01	1.08E-01	9.48E+02	1.093E-02	1.102E-03	6.647E-05
Carbon disulfide	9.00E+01	2.40E+01	NA	7.05E-02	6.18E+02	7.133E-03	7.195E-04	4.333E-05
Formaldehyde	2.50E+01	1.60E+01	7.60E-02	6.56E-02	5.75E+02	6.637E-03	6.695E-04	4.032E-05
Methyl chloride	7.70E+02	2.00E+02	5.60E-01	9.68E-02	8.48E+02	9.794E-03	9.879E-04	5.946E-05
Methyl ethyl ketone	7.40E+03	4.70E+03	NA	1.31E-01	1.15E+03	1.325E-02	1.337E-03	8.057E-05
Methyl isobutyl ketone	NA	NA	NA	8.04E-02	7.04E+02	8.135E-03	8.206E-04	4.936E-05
Methylene chloride	3.00E+03	8.00E+02	2.20E+00	2.13E-01	1.87E+03	2.155E-02	2.174E-03	1.310E-04
Phenol	3.20E+02	1.50E+02	NA	1.00E-01	8.76E+02	1.012E-02	1.021E-03	6.143E-05
Proponal	NA	NA	NA	1.70E-01	1.49E+03	1.720E-02	1.735E-03	1.043E-04
Toluene	4.40E+03	3.00E+03	NA	5.90E-02	5.17E+02	5.970E-03	6.022E-04	3.625E-05
Vinlidene chloride	1.30E+02	6.30E+01	NA	1.59E-01	1.39E+03	1.609E-02	1.623E-03	9.775E-05
Xylenes	5.40E+03	3.50E+03	NA	7.63E-02	6.68E+02	7.720E-03	7.787E-04	4.684E-05
Hydrogen Chloride	2.10E+02	5.60E+01	NA	1.29E+01	1.13E+05	1.305E+00	1.317E-01	7.945E-03
Fluorine	6.00E+00	1.60E+00	NA	1.18E+01	1.03E+05	1.194E+00	1.204E-01	7.254E-03
Chromium	1.50E+01	4.00E+00	NA	6.22E-02	5.45E+02	6.293E-03	6.348E-04	3.822E-05
Manganese	2.50E+01	7.90E+00	NA	2.81E-01	2.47E+03	2.843E-02	2.868E-03	1.728E-04
Mercury	1.50E+00	4.00E-01	NA	1.13E-01	9.88E+02	1.143E-02	1.153E-03	6.928E-05
Nickel	4.50E-01	1.20E-01	2.10E-03	5.98E-02	5.24E+02	6.050E-03	6.103E-04	3.674E-05
Selenium	6.00E+00	1.60E+00	NA	1.40E-01	1.22E+03	1.416E-02	1.429E-03	8.583E-05
Hydrogen Cyanide	1.00E+02	4.00E+01	NA	2.33E+00	2.04E+04	2.357E-01	2.378E-02	1.431E-03

D. Additional Impacts Analysis

1. Growth Analysis

The applicant proposes that approximately 100-120 permanent new positions will be needed for operation of the new Units 3 and 4 at SGS. It is estimated that half of the positions will be filled with local residents from Springerville and other local communities, and half will be filled by relocated workers from more distant areas. An increase of approximately 50 workers will result in a total population increase of 100-200 people. The 2000 U.S. Census shows the Springerville/Eager area to be inhabited by approximately 8000 people. The increase of around 2 percent in population is not expected to generate commercial growth or industrial growth, other than some initial increase in housing

Increases in air emissions from this population influx are primarily a result of the increase in vehicle exhaust from the family automobiles. The existing commercial base of the area is expected to be able to handle this influx without major construction and resulting air emissions. Therefore, the applicant estimates that no significant growth-related air quality impacts will occur. The department concurs.

2. Soils and Vegetation Impacts Analysis

R18-2-407.I.1 requires that the PSD permit application include an analysis of the impacts that emissions from proposed facility and from secondary growth will have on soils and vegetation. The applicant was unable to identify any specific sensitive species for soil and vegetation in the project vicinity. The applicant did assess predicted modeled impacts on alfalfa , which is farmed in Apache County. The applicant showed that maximum impacts of NO_2 were 2% of the levels found to inhibit photosynthesis in alfalfa. The applicant also compared predicted modeled impacts to screening levels found in the EPA document, “A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals”, EPA 1980). None of the predicted maximum concentrations were greater than or equal to the screening concentrations. Therefore, the results indicate that the project will not adversely impact soils and vegetation in the area.

3. Visibility Impacts Analysis

R18-2-407.I.1 and R18-2-410 require that the PSD permit application include an analysis of the impacts that emissions from proposed facility and from secondary growth will have on visibility. The PSD application included plume blight analyses for the 3 identified Class I areas of Mount Baldy Wilderness Area, Petrified Forest National Park, and Gila Wilderness Area.

The plume blight analyses were conducted using U.S. EPA's VISCREEN model A Level 2 meteorological frequency analysis was conducted following EPA guidance provided in the Workbook for Plume Visual Impact Screening and Analysis. The analysis estimates, by season, the worst-case conditions for The Mount Baldy Wilderness Area, the nearest Class I area. Wind speed and atmospheric stability comprise are the only parameters used to define these conditions. VISCREEN evaluates the potential for a visible plume to occur through a plume perceptibility parameter, Delta E. Under ideal viewing conditions, a Delta E value greater than 2.0 may be indicative of a discernable plume. The VISCREEN analysis indicates that , for those angles comprising the possible range of realistic geometry , the criterion of 2.0 is not exceeded.

4. Class I Area Impacts Analysis

The applicant assessed impacts on the 3 above mentioned Class I areas Increment analysis for these areas are presented in Section VII.A.2.a. *Modeling Results - Comparison with NAAQS and PSD Increments*.

a. Regional Haze Analysis

A regional haze analysis was conducted for all three Class I areas utilizing EPA's CALPUFF model, following guidance provided by the National Park Service which relied upon the most recent Interagency Workgroup on Air Quality Modeling (IWAQM) guidance. The applicant adhered to FLAG guidance recommending usage of seasonal extinction coefficients and seasonal relative humidity factors in the CALPOST post-processing. PM10 emissions were estimated as 23 percent filterable and 77 percent condensible.

Table VII-D-1 shows the result for the regional haze impacts on all three Class I areas. All impacts are less than 5 percent except for the Mount Baldy Wilderness Area, which is 5.14 percent. Due to the conservativeness of the modeling approach, both with techniques and emission calculations, the FLM agreed that the impacts were not likely to be adverse.

b. Acid Deposition, Flora and Fauna

An analysis of acid deposition and Flora and fauna was not done by the applicant because the net increase in NO2 and SO2 emissions for the project are zero.

Table VII-C-1 PSD Class I Regional Haze Impact

Location	*Peak Regional Haze Impact*
Gila Wilderness Area	2.23%
Petrified Forest Nat Park	2.64%
Mount Baldy Wilderness Area	5.14%
Screening Level Threshold	5%

E. Conclusions

The applicant has adequately demonstrated compliance with the NAAQS and PSD increments. None of the 24 air toxics evaluated were predicted to have impacts above the AAAQG. The visibility analysis revealed no discernable plumes at the nearest Class I area. Regional haze impacts at all 3 evaluated Class I areas were deemed "insignificant" by the National Park Service and Forest Service. No impacts were determined to be unacceptable.