Desert Rock Energy Co., PSD Appeal 08-03
Conservation Petitioners' Exhibits

EXHIBIT 42

4L

AFFIDAVIT OF VICTORIA R. STAMPER

I, VICTORIA R. STAMPER, declare as follows:

1. I am over 18 years in age and have personal knowledge of all statements made in this affidavit.

2. I have eighteen years of experience implementing the Clean Air Act requirements. My area of expertise includes the prevention of significant deterioration (PSD) air quality regulations. My resume is part of the administrative record in this matter and can be found as an attachment to Petitioners' November 13, 2006 comment letter at AR 66 (which is located in the Administrative Record at folder "ltr_23_attachments.zip," subfolder "Stamper Report and attachments," and file "stamper cv.pdf"), and it is also attached hereto as Exhibit A to this Affidavit.

3. I reviewed the sulfur dioxide (SO_2) increment analyses conducted by the owner of the proposed Desert Rock Energy Facility (DREF), Sithe Global Power, LLC (Sithe), among other parts of the Desert Rock PSD permit application. Specifically, I reviewed the May 2004 Desert Rock PSD Permit Application, and the January 2006 and June 2006 updates to the Class I and Class II PSD increment analyses conducted as part of the Desert Rock PSD permit application. I also reviewed the EPA's Ambient Air Quality Impact Report (AAQIR) prepared for the draft Desert Rock PSD permit.

4. In addition, I reviewed documentation in EPA Region IX's Desert Rock permit file obtained by Petitioners from EPA Region IX regarding the cumulative SO_2 increment analyses conducted for the proposed Desert Rock PSD permit. I also conducted my own research on issues regarding some of the assumptions made in determining the emissions that affect SO_2 increment for the Desert Rock cumulative SO_2 increment analysis.

5. I authored a report dated November 9, 2006 entitled "Review of the SO_2 PSD Increment Consumption Emission Inventory for the Desert Rock Prevention of Significant Deterioration Permit," which was in comments on the draft PSD permit

issued by EPA Region IX (which is located in the Administrative Record at folder "ltr_23_attachments.zip," subfolder "Stamper Report and attachments," and file "Nov92006 stamper report"). My report is also attached hereto as Exhibit B to this Affidavit. As discussed in detail in my 2006 report, I found that Sithe's cumulative SO_2 PSD increment analysis was significantly defective. For numerous reasons detailed in my 2006 report, I found that Sithe's methodology to determine the SO_2 emissions reflective of the baseline concentration at Units 1 and 2 of the San Juan Generating Station (SJGS) and at all 5 units of the Four Corners Power Plant (FCPP) resulted in improperly inflated baseline emissions from these emission units. I also found that Sithe's methodology for determining the SO_2 emissions reflective of the baseline concentration at the SJGS Units 1 and 2 was in error because the methodology, if applied to all four SJGS units, would allow the facility to exceed its 3-hour average plant-wide cap of 13,000 pounds per hour that applies under the New Mexico State Implementation Plan (SIP). I also found that Sithe's methodology for determining current actual emissions was inconsistent with longstanding EPA policy.

6. As part of my 2006 report, I developed a new increment-affecting emissions inventory for Units 1 and 2 of the SJGS to take into account a few of the deficiencies I identified in Sithe's methodology for determining SO_2 emissions for these two emission units reflective of baseline concentration (but without making any changes to the SO_2 emissions considered to be reflective of current actual emissions from the SJGS units or any of the other sources modeled). Specifically, I developed a Scenario 1 inventory for SJGS Units 1 and 2 which assumed that these units neither expanded or consumed the available SO_2 increment. I also developed a Scenario 2 inventory for SJGS Units 1 and 2 which assumed the baseline emissions of these two emission units were equivalent to their share of the 3-hour average 13,000 pound per hour SO_2 emission limit that applies on a plant-wide basis under the New Mexico SIP. Exhibit B hereto at pp. 32-35. Khanh Tran, of AMI Environmental, modeled these two scenarios, among others, and presented

his results in a November 9, 2006 report entitled "Cumulative SO_2 Modeling Analyses of Desert Rock Energy Facility and Other Sources at PSD Class I Areas." This Tran report is also part of the Administrative Record (located in the Administrative Record at folder "ltr_23_attachments.zip," subfolder "Stamper Report and attachments," and file "AMI_Modeling_Desert_Rock.pdf"), and is also attached hereto as Exhibit C. As shown in the Tran report, modeling of these two scenarios found that the 3-hour average and the 24-hour average SO_2 increments would be violated in Mesa Verde National Park, which is the closest Class I area to the proposed Desert Rock facility as well as to the SJGS and the FCPP[1]. Exhibit C at p. 4 (Table 1). Thus, this modeling shows that addressing just some of the deficiencies in Sithe's methodology for determining SO_2 emissions reflective of baseline concentration at SJGS Units 1 and 2 makes the difference between whether the Desert Rock facility will contribute to an SO_2 increment violation or not.

7. After EPA issued the Final PSD Permit in this matter, I reviewed EPA's Response to Comments regarding the cumulative SO_2 PSD increment analysis conducted for the Desert Rock PSD Permit. Specifically, I reviewed pages 131-134 of the "EPA Responses to Public Comments on the Proposed Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility" dated July 31, 2008, hereinafter referred to as EPA's Response to Comments, which is part of the Administrative Record in this matter and can be found at AR 120. No other part of EPA's July 31, 2008 response to public comments, or its response to late-filed public comments, address the cumulative SO_2 increment analysis conducted for the Desert Rock PSD permit.

8. EPA agreed with one of my comments that "baseline emissions for [SJGS] may have been overestimated" AR 120 at p. 132., which means that after receiving comments on the proposed PSD permit, EPA found that Sithe's 2006 cumulative SO_2 increment

[1] See Figure 6-11 of May 2004 DREF PSD Permit Application (at 6-34) for distances between DREF and Class I areas in the region. AR 12 at p. 6-34.

modeling was inadequate. EPA also agreed with my comment that the SO_2 increment expansion for the Cameo Station was not properly documented. AR 120 at 131.

9. Between issuance of the proposed Desert Rock PSD permit in 2006 and the final Desert Rock PSD permit in July of 2008, EPA conducted new SO_2 increment modeling analyses. EPA stated that it modeled twelve new cumulative SO_2 increment scenarios for the Desert Rock PSD permit. At least one of the emissions scenarios modeled appears to have been made to respond to my comment, which EPA agreed with, that baseline emissions for SJGS may have been overestimated. AR 120 at pp. 133-134.

10. I was not consulted on any of the new modeling analyses, nor was I provided with the opportunity to review the new increment modeling analyses prior to issuance of the final Desert Rock PSD permit.

11. EPA has not provided a modeling report describing in detail the methodologies and assumptions used for determining the SO_2 increment-affecting emissions for its new twelve modeling scenarios. EPA described what it modeled in the twelve modeling scenarios in about one page of text in its response to comments. AR 120 at pp. 133-134.

12. More detailed modeling reports are typically prepared for a PSD permit especially when an increment analysis includes sources that were in existence as of the applicable baseline date and which have increased or decreased emissions in current years. For example, even Sithe provided modeling reports in its 2004 Desert Rock PSD permit application. See AR 12, Attachment 6 to Sithe's May 2004 DREF PSD Permit Application (entitled "Cumulative Modeling Inventory Documentation"). See also AR 37 at p. 4-23 and pp. A-1 through A-2 (Sithe's January 2006 Desert Rock PSD Permit Application – Class I Area Modeling Update, Section 4.5 including Table 4-11 which identifies the increment consuming or increment expanding emission rates modeled for each source in the cumulative modeling analysis) and also Appendix A, Section 2.0 and Appendix A ("Cumulative SO_2 PSD Inventory").

13. Unfortunately, the new modeling performed by EPA after the close of the public comment period on the proposed Desert Rock PSD permit only provides a brief explanation of the twelve different scenarios EPA modeled in the Response to Comments at pages 133-134, AR 120 at pp. 133-134. After EPA issued the final PSD permit, EPA also made available some of its modeling files for these twelve modeling runs, which were included as Appendix B to its Response to Comments, on its website at http://www.epa.gov/region09/air/permit/desert-rock/administrative.html. The zipped file entitled "rtc_mod_prep.zip" in these Appendix B modeling files contains ten spreadsheets that were apparently relied on in developing the various increment-affecting emissions that were modeled in the twelve modeling scenarios. In this zipped file, there are also three different text files that attempted to identify and explain the modeling files. First, there is "readme.txt" which identifies all of the ten spreadsheets and the other text files with a brief, one line explanation. Second, there is a file with name "mod_cmt_prep.txt" which identifies the spreadsheets that apply to "Cameo SO2 increment effect," "Navajo sources SO2 increment effect," "DREF low level sources," "SO2 increment modeling," and "PM10 for Four Corners Power Plant." Last there is a text file with filename "mod_file_expl.txt" which very briefly describes the six baseline scenarios in one line or less and indicates that scenarios of current versus future emissions were also evaluated. This file also explains filenaming conventions for each of the twelve scenarios modeled. This file refers to the spreadsheet with filename "Inc_em_scenarios.xls" in which scaling factors were developed for each scenario that were presumably applied to a certain model run of emissions in a post utility program.

14. I reviewed the spreadsheet "Inc_em_scenarios.xls," a spreadsheet with nine different worksheets, and it does not clearly identify the increment affecting emissions modeled for each FCPP and SJGS unit for each of the twelve scenarios. I found the spreadsheet to be very confusing and it did not help me understand the basis for each of the emissions scenarios modeled. According to the "notes" worksheet of

"Inc_em_scenarios.xls," the worksheet "Inc" has the "table of increment consuming emissions, current and future." However, a review of the table in the "Inc" worksheet found that it does not show the increment-affecting emissions for each unit of the FCPP and SJGS. Instead, it shows plant-wide emissions considered to be baseline, current and future for each plant. The tables also show only two baseline scenarios, which is in contrast to EPA's response to comments in which EPA stated that it modeled three baseline scenarios. AR 120 at p. 133.

15. In theory, EPA's new model run with an increment inventory for FCPP and SJGS based on its "baseline 2" (i.e., "including only SJGS units 1 and 2 at their share of the SJGS's allowed 13,000 lb/hr") and current 1-hour 99th percentile emission rates should be very similar to the increment affecting emissions that I developed for a "Scenario 2 model run" that was performed by Khanh Tran of AMI Environmental in 2006. Exhibit B hereto at pp. 32-35 which describes the basis for the Scenario 2 emissions scenario. AMI Environmental's model run for Scenario 2 was based on the same versions of CALPUFF and its supporting programs and the same meteorological data (although only year 2001 was modeled) as used by ENSR who performed the cumulative SO_2 increment modeling for the Desert Rock PSD Permit Application. See Exhibit C hereto at pp. 2-3. AMI Environmental's model run completed in 2006 was also based on the same emissions and stack parameters of the Desert Rock facility and other cumulative sources shown in Table 4-11 of the Sithe's January 2006 Class I Area Modeling Update (AR 37 at p. 4-23), except that low level emissions sources associated with the Desert Rock facility were included and also two different emissions scenarios for SJGS Units 1 and 2 were modeled. Exhibit C hereto at p. 3. AMI Environmental's model run of SJGS Emissions Scenario 2 predicted a high-second-high, 3-hour average SO_2 concentration of 34.669 $\mu g/m^3$ and a high-second-high, 24-hour average SO_2 concentration of 5.9181 $\mu g/m^3$ at Mesa Verde National Park, in violation of both the 25 $\mu g/m^3$ 3-hour average Class I SO_2 increment and the 5 $\mu g/m^3$ 24-hour average Class I SO_2 increment. Exhibit

C hereto at p. 4 (Table 1). Even though EPA's new model run based on increment affecting emissions determined by its "baseline 2" and current 1-hour 99th percentile emissions should have been very similar, if not identical, to AMI Environmental's Scenario 2 2006 model run, EPA's model results "showed no Class I or Class II SO_2 increment violations under any of the twelve scenarios." AR 120 at p. 134. This indicates that EPA made significant changes to Sithe's January 2006 Class I SO_2 increment modeling which EPA relied upon in 2006 when it proposed the Desert Rock PSD permit for public review and comment. Yet, EPA has not provided clear documentation to describe or support all of the changes it made to Sithe's January 2006 Class I SO_2 increment modeling analysis in its new modeling analyses discussed in its Response to Comments.

16. In summary, the administrative record is incomplete because it does not contain a detailed and comprehensible statement of the methodologies used by EPA in conducting its new SO_2 increment analyses which EPA is clearly now relying on in issuing the Desert Rock PSD Permit. As such, given this incomplete administrative record, it is difficult to determine whether EPA properly conducted the new SO_2 increment analyses.

17. To remedy this defect in the administrative record, I suggest that EPA re-issue for public comment the Desert Rock PSD permit and include in the administrative record a detailed and comprehensible discussion of the methodologies used by EPA in conducting its 12 new modeling scenarios and a description of all emissions data used by EPA in running these modeling scenarios.

I declare that the above statements are based on my personal knowledge and are true, accurate, and complete to the best of my knowledge.

9-30-08

Date

Victoria R Stamper

Victoria R. Stamper

State of MINNESOTA County of ITASCA

Debra L. Lengeling

Sept 30, 2008

Date

My commission expires Jan 31, 2010

DEBRA L. LENGELING
Notary Public–Minnesota
My Comm. Expires Jan. 31, 2010

STAMP

Exhibit A
to September 30, 2008 Affidavit of Victoria R. Stamper

Resume of Victoria R. Stamper

Victoria R. Stamper

P.O. Box 43
Grand Rapids, MN 55744
(218) 326-6768
vstamper@skypoint.com

Skills and Areas of Expertise

Comprehensive knowledge of the Clean Air Act - accomplished in the requirements for new source review (NSR) and prevention of significant deterioration (PSD) construction permits, Title V operating permits, Class I area protection, and state implementation plans including analysis of plans for compliance with the national ambient air quality standards.

Superior research abilities - with over fifteen years of investigating air issues from both a government and citizen perspective by assessing industry and state government compliance with Clean Air Act requirements.

Proficient in analyzing and interpreting laws and regulations - developed through ten years at the EPA performing detailed reviews of state regulations to ensure consistency with federal requirements and through four years of assisting citizen suit enforcement.

Experienced in litigation – six years experience performing research and preparing briefs and other related documents for citizen suit litigation and permit appeals.

Excellent writing abilities – known for thoroughness and accuracy in written work products.

Professional Experience

Air Quality Consultant — April 2003 to Present

I provide consulting services to environmental groups on a variety of air quality issues, including:

- Reviewing and preparing comments on all aspects of air quality construction and operating permit applications and proposed permits for new coal-fired power plants in the West.
- Providing technical expertise and legal support for the appeal of air quality permits that do not comply with federal or state clean air requirements.
- Investigating facility compliance with federal and state air quality regulations.
- Analyzing proposed or available mercury controls for coal-fired power plants.
- Evaluating and commenting on air quality analyses and environmental impact statements for proposed oil and gas development in the West.
- Critiquing prevention of significant deterioration increment analyses.
- Reviewing, commenting, and providing case study evaluations of new source review rule revisions, both at the federal and state level.
- Reviewing and commenting on Class I visibility protection plans.

Environmental Engineer/Legal Assistant
Reed Zars, Attorney at Law
910 Kearney Street
Laramie, WY 82070

May 2001 to April 2003

Responsibilities included:

- Investigating industrial facilities' compliance with Clean Air Act requirements through review of public documents.
- Assisting with all aspects of litigation including research for and writing of notices of intent to sue, complaints, and other briefs.
- Researching pollution reduction measures and effectiveness for settlement negotiations.
- Reviewing and preparing written comments on proposed EPA state implementation plan approvals regarding topics such as opacity regulations, emission limit exemptions, Class I visibility plans and permitting regulations.
- Reviewing and preparing comments on proposed air quality construction and operating permits.

New Source Review Program Manager
Air and Radiation Program
U.S. Environmental Protection Agency, Region VIII
999 18th Street, Suite 300
Denver, Colorado 80202

December 1990 to April 2001

Responsibilities included:

- Serving as the Region VIII lead for state rules regarding the new source review and prevention of significant deterioration programs, as well as other industrial source control measures.
- Reviewing all aspects of prevention of significant deterioration increment analyses.
- Reviewing state implementation plans for consistency with requirements of Clean Air Act.
- Preparing documents to justify EPA approval or disapproval of state submittals.
- Educating and assisting tribes in developing regulations for tribal implementation plans.
- Participating in workgroups to ensure national consistency and provide input on rulemakings.
- Reviewing state operating permit programs under Title V of the Clean Air Act.
- Researching and compiling the EPA-approved state implementation plans.
- Developing and reviewing state implementation plans for particulate matter nonattainment areas, as well as assisting in the preparation of requests to redesignate to attainment.
- Reviewing environmental impact statements for consistency with Clean Air Act requirements.
- Serving as primary contact for air quality issues in the state of Wyoming.

<u>Environmental Engineer</u>
Envirometrics, Inc.
Seattle, Washington

August 1989-
July 1990

Responsibilities included:

- Designing components of research projects pertaining to pollution control systems.
- Developing testing criteria and measuring the effectiveness of these control systems.
- Preparing air pollution permit applications and related documentation for industrial sources, including compiling emission inventories and input data for modeling of ambient air quality impacts on Class I areas.

Papers and Reports

- Banerjee, Shilpi, & Vicki Stamper, *Mercury Air Pollution The Case for Rigorous MACT Standards For Subbituminous Coal*, prepared for Rocky Mountain Office of Environmental Defense and the Land and Water Fund of the Rockies, May 2003.

- Ruby, Michael G., Victoria R. Stamper, & You-ran Wang, *Removal of Odorant Compounds by Packed Tower Scrubbing*, presented at November 1989 Air and Waste Management Association conference in Spokane, WA.

Education

Bachelor of Science Degree, June 1989
Civil Engineering, Michigan State University

CONSTRUCTION PERMIT APPLICATION

FOR SAN JUAN GENERATING STATION, UNIT 1

PUBLIC SERVICE COMPANY OF NEW MEXICO

MAY 15, 1973

...of New Mexico
...ronmental Improvement Agency
... Quality Control Office
... O. Box 2348, Room 505, PERA Bldg.
...anta Fe, New Mexico 87501

FOR EIA USE ONLY	
Application No.	63
App. Rec'd. Date:	May 18, 1973
Date App. Complete	
Received By:	Bill Kopp
Reviewed By:	D. E. Zeh
Approved/Disapproved:	Approved Conditionally
Date:	July 13, 1973

Supplemental data received 6/18/73 Dz;

PERMIT APPLICATION

FOR

AUTHORITY TO CONSTRUCT OR MODIFY SOURCES LOCATED WITHIN THE STATE OF NEW MEXICO (1)

Please answer all questions applicable to your specific business, operation, and products.
Use the abbreviation "N.A." for "not applicable" wherever appropriate.
Submittal of Environmental Impact Information may be required to complete this application. (2)

SECTION I - GENERAL DATA

1. Name of Company: Public Service Company of New Mexico 2. Date Submitted: ____

3. Main Office Address: P.O. Box 2267, Albuquerque, New Mexico 87103 Phone: 842-2700

Owner of Business: Investor-owned Utility Address: ____

Person to Contact: C. D. Bedford Title: Vice President Phone: 842-2924

4. Address or location of new plant or modification: Fruitland, New Mexico

Is U.S.G.S. quadrangular map or equivalent attached? (3) Yes

5. Describe briefly nature of business and/or function of modifications and products: Coal fired unit for electricity generation.

6. Is this site permanent? Yes If not, how long will it be occupied? A minimum of 35 years

7. Normal operating schedule: 24 hours per day, 7 days per week, 4 weeks per month, 12 months per year.

Specify seasonal and/or peak operating periods: Base loaded unit operating at a maximum of 85% capacity factor.

Notes: (1) Submitted in accordance with Air Quality Control Regulation No. 702 . PERMITS
(2) Notification of such requirement or the need for other additional information required to complete this application will be given to the applicant by the Air Quality Office within 10 days after receipt of the application. Filing of the application will not be considered to be complete until the date of submittal of such additional information. The granting or denial of the permit will be made within 30 days after this completion date.
(3) Regulation No. 702 , Section D, Item 5 requires that this application be accompanied by a U. S. Dept. of the Interior Geological Survey quadrangular map or equivalent map showing the exact location of the proposed construction or modification.

Revised: 7 August, 1972

SECTION 2 - FUEL USAGE

PERMIT # 13

M

Source No.[1]	Type of Unit[2]	Unit Manufacturer	Rated Capacity 10^6 BTU/Hr.[3]	FUEL DATA[4], [9]				
				Fuel Type[5]	Amount[6] Per Year	Heat[7] Content	Percent[8] Sulfur	Percent[8] Ash
1	Steam Generator	Foster-Wheeler	3420	Coal	1,299,250	9800 BTU/Lb.	0.8	18
			Start-up	#2 Oil	--	19741 BTU/Lb.	0.18	0

Notes: (1) Give a different number to represent each unit; give corresponding data opposite the same number in Sections 3 through 9.
(2) Boiler, oven, furnace, gas engine, diesel engine, gas turbine, space heater, etc.
(3) Give maximum rate as well as normal rate, if different.
(4) If auxiliary fuel or different fuel used "on standby", also give data for that fuel.
(5) Natural gas; LPG; bituminous coal; anthracite coal; No. 1, 2, 4, 5, or 6 fuel oil; refinery gas; wood; etc.
(6) Million cubic feet of gas; tons of coal; gallons or barrels of fuel oil; pounds of LPG; etc.
(7) Higher heating value; if unknown, give name and address of supplier.
(8) Sulfur and ash contents should be average percentages by weight; if not known, give name and address of fuel supplier. Sulfur and ash contents are not required if clean natural gas is used as the fuel.
(9) Attach process flow sheet, including material balance for the combustion plant.

SECTION 3 - MATERIALS PROCESSED AND PRODUCED

A. RAW MATERIALS PROCESSED

Source No.[1]	Type	Composition[2]	Condition[3]	Quantity[4]
		NA		

B. MATERIALS PRODUCED

		NA		

Notes: (1) Corresponding to numbers in Sections 2 - 9.
(2) Give each major component with weight percentages and chemical compositions if known.

SECTION 4 - SOURCE EMISSIONS

Source No.(2)	Process or Operation (3)	Quantity of Gases Discharged(4)	ESTIMATES OF AIR POLLUTANTS(9) Pollutant No. 1		Pollutant No. 2		Pollutant No. 3 (8)		Basis of Estimates(7)
			Type (5)	Quantity(6)	Type (5)	Quantity(6)	Type (5)	Quantity(6)	
1	Combustion	769240	Particulate	187,100	SO_2	20,790	NO_X	5730	Combustion Calculations
				(187,600)		(20,849)			

Notes: (1) Uncontrolled emissions of pollutants discharged to control equipment or to the atmosphere if uncontrolled.
(2) Give a different number to each major primary source, corresponding to source numbers in Sections 2-9.
(3) Smelter furnace, asphalt plant drier, iron-melting cupola, cement manufacturer-dry process, solvent cleaner, etc.
(4) Gas flow rate in standard cubic feet per minute (at 70° F, 14.7 lb./sq. in.) (Total of all gases from each source)
(5) Particulate matter (give chemical description), Sulfur Dioxide, Carbon Monoxide, Hydrogen Sulphide, Nitrogen Oxides, etc.
(6) In tons (2000 lb.) per year.
(7) From process material balances, field tests by plant or equipment manufacturer, etc.
(8) If more than 3 types of pollutants are expected, use 2 or more spaces for the same source, or attach additional sheets if required.
(9) Give values at maximum process rate as well as at normal rate if different.

SECTION 5 - AIR POLLUTION CONTROL EQUIPMENT (6)

Source No.(1)	GAS CLEANING EQUIPMENT Type (2)	Manufacturer and Model No.	AIR POLLUTANTS EMITTED TO STACKS(3) Pollutant No. 1		Pollutant No. 2		Pollutant No. 3(6)		Basis of Estimates (7)
			Type (4)	Quantity(5)	Type (4)	Quantity(5)	Type (4)	Quantity(5)	
1	ESP	Western	Part.	374					Manf. Guarantee
1	Scrubber	Wellman or Kellogg	Part.	255	SO_2	4330 (79.2% Control)			Design Criteria
1	Boiler Design	Foster-Wheeler					NO_X	5730	Manf. Guarantee

Notes: (1) Corresponding to numbers in Sections 2-9.
(2) Cyclone, scrubber, electrostatic precipitator, baghouse, etc.
(3) Estimated emissions after gases have passed through control equipment; give values at max. process rate as well as normal rate, if differe
(4) Particulate matter, etc. (See Note 5, Section 4.)
(5) In tons (2000 lbs.) per year.
(6) See Note 8 above.

PERMIT # 13

Approximate expected capital investment of new X or modified ___ air pollution control equipment: $ 20,000,000

Capital investment and installation date(s) of already installed process and air pollution control equipment: ______

SECTION 6 - STACK DATA

Source No.	Stack Height, Ft.	Inside Diameter, Ft.	EXIT GAS CONDITIONS (1)			SAMPLING PORTS		
			Temperature °F	Velocity Ft./Sec.	Moisture % by Volume	Number	Size	Location (2)
1	400	20	116	62	16.4	4@90°	4"x10'	130 ft. from top of stack

Notes: (1) If conditions are not at actual stack exit, specify location for which estimates are made.
(2) Example: 8 ports at 45°, 25' from top.

Location of 110/120 V ac electrical power nearest to stack: On sampling platform

What provisions are made for accessibility to stack sampling ports? On sampling platform

SECTION 7 - EMISSION MEASUREMENT EQUIPMENT

Source No.	Pollutant	Type of Instrument (1)	Manufacturer - Model No.	Range (2)	Sensitivity	Accuracy
1	NO_x	Chemiluminescent	Thermoelectric 10	0-10000 ppm	-	±1%
or	NO_x	NDIR	Beckman	0-1000 ppm	-	±1%
1	SO_2	Photometric	Du Pont 400 Series	0-1000 ppm	-	±2%
or	SO_2	Photometric	Meloy ESA 190	25-100 ppm	-	±2%
1	Particulate	Quartz microbalance	Celesco	10-100 $\mu g/m^3$	-	±10%
or	Particulate	Optical density meter	Lear Siegler RM4	Four dual ranges	-	±3%

Notes: (1) Ultra Violet Photometric Analyzer, NDIR Photometer, Opacity Meter, EPA Sampling Train, etc.
(2) 0-1000 ppm, 0-50 $\mu g/m^3$, 0-100% opacity, etc.

A. Describe any toxic chemicals used or emitted in processes: (5)

Source (1)	Description of Chemicals (2)	Quantity Emitted to Atmosphere (3)	How, where emitted (4)
	ANALYSES OF COAL ATTACHED AS EXHIBITS A AND B.		
	DATA UNAVAILABLE TO DETERMINE TOXIC CHEMICAL QUANTITIES EMITTED.		

Notes: (1) Give source number from Section 4 if previously listed; if not, describe source of toxic chemical emission.
(2) Give chemical composition if known.
(3) Give in lb. per hr., day, week or year (specify which).
(4) If emitted in separate stack, give stack conditions; if added to another stack flow, specify which one.
(5) List all chemicals considered harmful in small amounts or concentrations and not covered in Sections 4 & 5. (Ex: mercury vapor, [illegible])

B. Describe sources and characteristics of any odors emitted from plant processes:

None

Section 9 - Waste Product Disposal

Normal on-site combustion operating schedule: 24 hours per day 7 days per week 52 weeks per year.

Seasonal or peak operating periods (specify): Base loaded @ 85% capacity factor

Source No. (1)	Waste Material: Type (2)	Waste Material: Amount (3)	Method of Disposal (4)	Incinerator Capacity Lb. per Hr.	Auxiliary Fuel Used (5)	Type and Efficiency of Air Cleaning Equipment (6)	Estimate of Air Pollutant: Type (7)	Estimate of Air Pollutant: Quantity per Year (8)
1	Coal ash	233,620	landfill			See Sect. 5	See Sect.	4
1	Sulfur(Wellman)	8,230	landfill/sale			"	"	
or	$CaSO_4$ (Kellogg)	53,542	landfill/sale					

Notes: (1) Corresponding to numbers in Sections 2-9.
(2) Waste paper, wood chips, rubbish, garbage, etc.
(3) Pounds, tons or gallons per year.
(4) Incinerator, single chamber; incinerator, double chamber; sanitary landfill, etc.
(5) Give type and quantity used in incinerator or other burner.
(6) Give general type (cyclone, scrubber, etc.) if any, weight efficiency.
(7) State major pollutant (ash, smoke, SO_2, etc.)
(8) Give estimate in pounds or tons.

Section 10 - Certification

I, the undersigned, a responsible officer of the applicant company, certify that, to the best of my knowledge, the information [illegible] application, together with associated drawings, specifications and other data, give a true and complete representation of the planned new plant or modifications to an existing plant with respect to air pollution sources and control equipment. I also understand that any significant [illegible] errors, or misrepresentations in these data will be cause for revocation of part or all of this permit.

Name (type) C. D. Bedford Signed C D Bedford Title Vice President

EXHIBITS

FRUITLAND COAL FIE 6

	High Value	Low Value	Predicted Average *
Coal (as received)			
Heating Value BTU/lb	11,628	8,000	9,800
% Moisture	15.01	8.10	10.28
% Carbon	59.19	52.16	55.69
% Hydrogen	4.84	3.92	4.25
% Nitrogen	1.40	.90	1.10
% Chlorine	.09	.00	.03
% Sulfur	1.30	.59	.80
% Ash	22.45	12.59	18.00
% Oxygen	10.82	8.81	9.85
TOTAL			100.00

Ash	
Phosphorus Pentoxide, P_2O_5	0.08-0.23%
Silica, SiO_2	46.82-59.94%
Ferric Oxide, Fe_2O_3	2.90-6.13%
Alumina, Al_2O_3	22.77-31.37%
Titania, TiO_2	0.60-1.29%
Magnesia, MgO	0.62-4.76%
Lime, CaO	2.17-13.10%
Sulfur Trioxide, SO_3	1.17-6.32%
Sodium Oxide, Na_2O	0.66-3.09%
Potassium Oxide, K_2O	0.38-0.88%
Unknown	0.00-0.75%

* The predicted average is weighted by the seam thickness. It is not an average of the high and low values

SAN JUAN

JOY MANUFACTURING COMPANY
WESTERN PRECIPITATION DIVISION

WARRANTY - EQUIPMENT AND PERFORMANCE

1. The Seller will replace or repair without charge parts found to be defective in material or workmanship under normal and proper use (wear and tear from abrasion and/or corrosion excepted) within twelve (12) months of the date of initial operation or 1 December 1977, whichever occurs first. The responsibility of the Seller under this warranty will be limited to repair or replacement of the defective part, and he will not be responsible for dis-assembly, handling or re-installing costs associated with any warranty claim.

2. The Seller guarantees that the proposed equipment with two (2) 4'6" bus-sections de-energized will remove 99.8% of the entering particulate matter when operated at the rated capacity indicated on page ii; at the option of the Seller, an outlet loading of .0075 grain per actual cubic foot will satisfy the guarantee.

CONDITIONS OF WARRANTY

1. The equipment will be installed, adjusted and operated under the direction of Seller's representative, within its rated capacity and under normal conditions.

2. The determination of the collection efficiency will be by the testing procedures outlined by the specified ASME or EPA test procedures, using dry filtration methods for the definition of particulate matter.

3. If the performance tests are delayed, thru no fault of the Seller, the Buyer will put the equipment in first-class operating condition prior to the conducting of tests

4. The proposed equipment will be operated at steady-state conditions for a mutually agreed period prior to the performance of official efficiency tests. During this period, the Seller will have the right to conduct preliminary tests and make adjustments to the controls to optimize precipitator performance under actual conditions; no such adjustments will be made for a period of seven (7) days prior to efficiency testing, providing process conditions are not changed during that interim The Seller warrants that the proposed equipment will perform in accordance with, and subject to, the provisions of this proposal.

5. THERE ARE NO OTHER WARRANTIES, EXPRESS, STATUTORY OR IMPLIED, INCLUDING THOSE OF MERCHANTABILITY AND OF FITNESS FOR PURPOSE, NOR ANY AFFIRMATION OF FACT NOR REPRESENTATION WHICH EXTENDS BEYOND THE DESCRIPTION OF THE FACE HEREOF; SELLER'S WARRANTY WILL BE STRICTLY LIMITED TO THE PERFORMANCE SET FORTH IN THE TECHNICAL SPECIFICATION.

SAN JUAN UNIT 1 SCHEMATIC

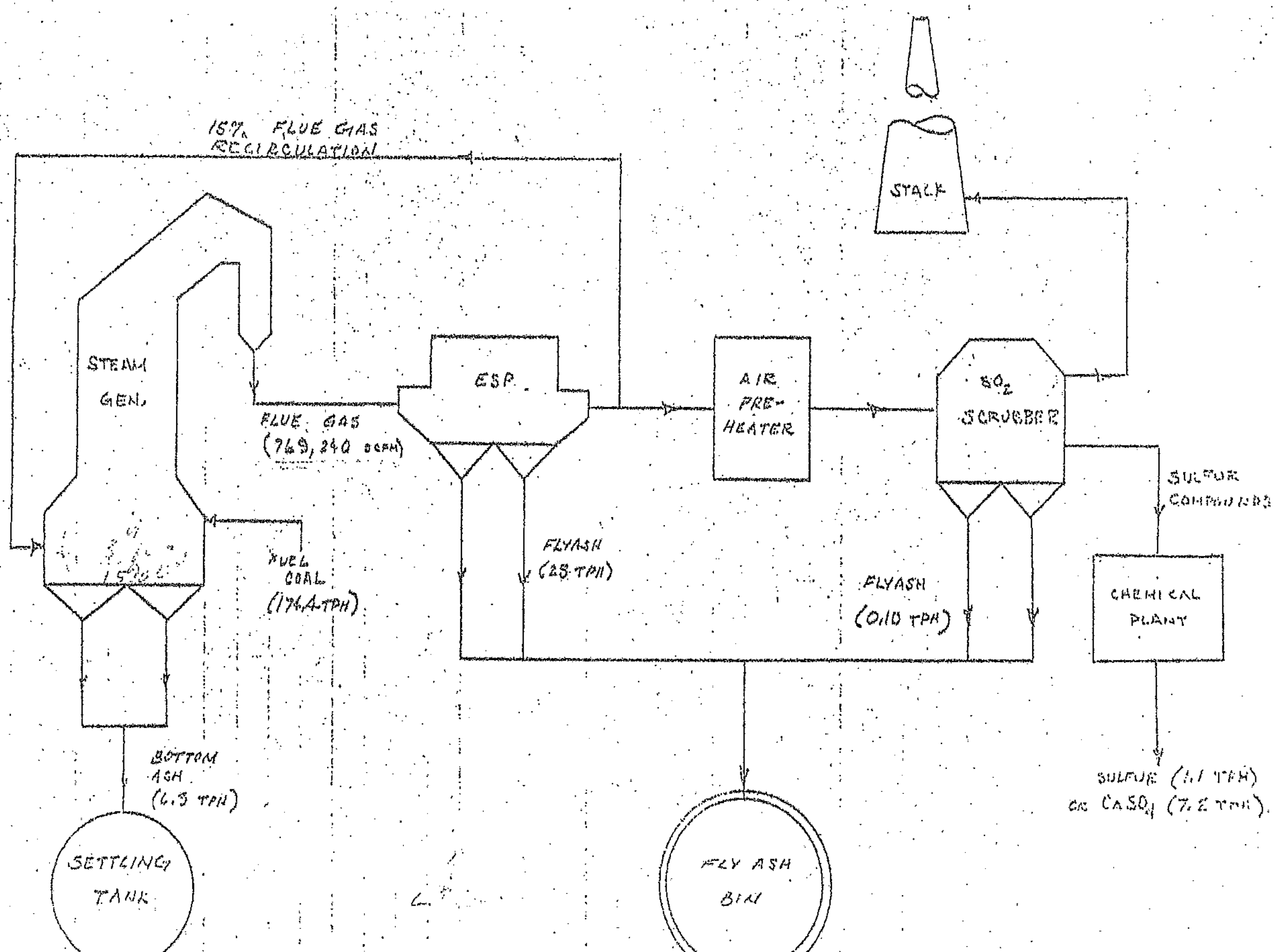


Exhibit B
to September 30, 2008 Affidavit of Victoria R. Stamper

November 9, 2006 Stamper Report Entitled
"Review of the SO2 PSD Increment Consumption Emission Inventory for the Desert Rock Prevention of Significant Deterioration Permit"

Review of the SO_2 PSD Increment Consumption Emission Inventory for the Desert Rock Prevention of Significant Deterioration Permit

November 9, 2006

Prepared by Vicki Stamper

In May 2004, a prevention of significant deterioration (PSD) application was submitted to authorize the construction of a 1,500 MW coal-fired power plant, the Desert Rock Energy Facility (Desert Rock), on Navajo Nation land about 25 miles southwest of Farmington, New Mexico by Sithe Global Power, LLC (Sithe). As part of that PSD permit application, cumulative PSD sulfur dioxide (SO_2) increment analyses were done for the 3-hour average and 24-hour average Class I and II SO_2 increments. Sithe completed updated Class I and II SO_2 PSD increment analyses in January and June 2006, respectively, which were ultimately submitted to EPA Region IX as part of the Desert Rock PSD permit application. In August 2006, EPA Region IX proposed to issue a PSD permit for the construction of Desert Rock.

While the updated Class I and II SO_2 PSD increment analyses indicated that Desert Rock would not cause or contribute to a violation of the SO_2 PSD increments, those analyses were based on air emissions inventories that were significantly flawed. In developing its PSD increment-affecting emission inventories, Sithe relied on assumptions that were unjustified and inconsistent with the PSD requirements of the Clean Air Act and associated regulations and guidance. EPA has proposed to find that Sithe followed appropriate modeling procedures and applicable guidance in determining that Desert Rock would not cause or contribute to violation of the PSD increments. Ambient Air Quality Impact Report (AAQIR), US EPA Region IX, at 35. This report details the flaws in Sithe's PSD increment analyses and explains why EPA's proposed acceptance of Sithe's modeling analyses is wrong.

I. BACKGROUND ON THE PSD INCREMENTS

As provided by section 160 of the Clean Air Act, the purpose of the PSD program of the Clean Air Act is as follows:

> 1) to protect public health and welfare from adverse air pollution impacts that could occur in a clean air area – that is, an area with air quality that is not in violation of the national ambient air quality standards (NAAQS);
>
> 2) to "preserve, protect, and enhance the air quality in national parks, national wilderness areas" and other "Class I" areas;
>
> 3) to ensure that growth occurs in a manner "consistent with the preservation of clean air resources;"

4) "to assure that emissions from any source in any State will not interfere with any portion of the applicable [state] implementation plan to prevent significant deterioration of air quality for any other State;" and

5) to ensure that any decision to allow increased air pollution in a clean air area is allowed only after "careful evaluation of all the consequences of such a decision" and that the public had an adequate opportunity to participate in the decision.

In a nutshell, the PSD program is to keep clean air areas clean and to not allow significant degradation of air quality in these areas, so that air quality does not deteriorate to the level of the NAAQS. In accordance with §160(2) of the Clean Air Act, Class I areas such as national parks and wilderness areas are only allowed a very limited amount of degradation of air quality.

One of the primary mechanisms Congress enacted to meet these mandates for sulfur dioxide (SO_2) and particulate matter pollution was the "maximum allowable increases over baseline concentrations," also known as the ambient air PSD "increments." See Section 163 of the Clean Air Act, 40 C.F.R. §52.21(c). With respect to SO_2, the Clean Air Act provides that the maximum allowable increases over baseline concentration are limited to[1]:

Table 1: SO_2 PSD Increments

Area	Maximum Allowable SO_2 Increase Over Baseline Concentration	Averaging Time
Class I	25 μg/m^3	3-hour
	5 μg/m^3	24-hour
	2 μg/m^3	Annual
Class II	512 μg/m^3	3-hour
	91 μg/m^3	24-hour
	20 μg/m^3	Annual

See Section 163(b) of the Clean Air Act, 40 C.F.R. §52.21(c).

The 3-hour and 24-hour average increments can be exceeded once per year as long as the total concentrations remain under the NAAQS. Section 163(a) of the Clean Air Act. Section 163(4) of the Clean Air Act also provides as an overarching requirement that the maximum allowable concentration of any air pollutant cannot exceed the primary or secondary national ambient air quality standards (NAAQS).

[1] Note that the Clean Air Act also provides maximum allowable increases over baseline concentration for Class III areas, a classification that would allow the most amount of degradation of air quality in an area. No area in the United States has been designated Class III, so the Class III increments are not provided in this table.

Class I areas are generally defined as those national parks and wilderness areas exceeding certain size thresholds that were in existence as of August 7, 1977. All other areas were designated as Class II. Section 162 of the Clean Air Act.

In order to understand how the increments are to be implemented, one needs to understand the concept of "baseline concentration." This term is defined as follows:

> (i) that ambient concentration level which exists in the baseline area at the time of the applicable minor source baseline date. A baseline concentration is determined for each pollutant for which a baseline date is established and shall include:
>
> > (*a*) the actual emissions representative of sources in existence on the applicable minor source baseline date except as provided in paragraph (b)(13)(ii) of this section;
> > (*b*) the allowable emissions of major stationary sources which commenced construction before the major source baseline date but were not in operation by the applicable minor source baseline date.
>
> (ii) The following will not be included in the baseline concentration and will affect the applicable maximum allowable increase(s):
>
> > (*a*) Actual emissions from any major stationary source on which construction commenced after the major source baseline date; and
> > (*b*) Actual emissions increases and decreases at any stationary source occurring after the minor source baseline date.

40 C.F.R. §52.21(b)(13). See also Section 169(4) of the Clean Air Act.

The baseline concentration is generally to reflect the concentration at the time of the "minor source baseline date." However, the definition of "baseline concentration" also specifically provides that actual emissions associated with construction at a major stationary source after the "major source baseline date" affect the available PSD increment. 40 C.F.R. §52.21(b)(13)(ii)(*a*). The major source baseline date is defined in the PSD regulations as January 6, 1975 for SO_2. 40 C.F.R. §52.21(b)(14)(i).

The minor source baseline date is defined as the date of the first complete PSD permit application submitted after August 7, 1977, for a source proposing to locate in an area designated as attainment/unclassified under section 107 of the Clean Air Act (i.e., a clean air area)[2]. 40 C.F.R. §52.21(b)(14)(ii). The minor source baseline date is set on a pollutant-specific basis. Only a source that will have significant emissions of SO_2 can trigger the minor source baseline date for SO_2 in an area. 40 C.F.R. 52.21(b)(14)(iii)(*b*). The minor source baseline date, which reflects *when* the baseline concentration is to be determined, is set for the entire "baseline area," and the baseline area includes any intrastate attainment/unclassifiable area in which the PSD source that sets the minor source baseline date proposes to locate and any areas where the proposed source would have an ambient impact equal to or greater than 1 $\mu g/m^3$ annual average. 40 C.F.R. §52.21(b)(15).

---

[2] Areas designated as attainment or unclassified are identified in 40 C.F.R. Part 81, Subpart C.

In the case of the DREF facility to be located in the immediate vicinity of four states, there are various applicable minor source baseline dates for SO_2 depending upon the area of concern. For the areas of concern in this case, the applicable SO_2 minor source baseline dates are provided in Table 2.

Table 2: Applicable SO_2 Minor Source Baseline Dates[3]

State/Class I Areas	SO_2 Minor Source Baseline Date
Entire State of Colorado	October 12, 1977
New Mexico[4] (San Pedro Parks Wilderness Area, Bandelier National Monument)	May 14, 1981
Arizona (Petrified Forest National Park, Grand Canyon National Park)	October 31, 1977
Utah (Canyonlands, Capitol Reef, and Arches National Parks)	Mid-1979 or earlier[5]
San Juan County New Mexico (for the Class II SO_2 increment)[6]	October 2, 1978

In theory, once the minor source baseline date is triggered for an area, the baseline concentration is to be determined, and the maximum allowable increase is added to that baseline concentration to determine the total concentration of the pollutant that is allowed to occur in an area. In practice, however, it is extremely difficult to determine the total concentration of a pollutant allowed in a clean air area via this method. This is due in large part to intricacies in the definition of "baseline concentration" enacted by Congress including, for example, that some emissions occurring before the minor source baseline date actually consume increment (i.e., emission changes associated with construction at major stationary sources). See section 169(4) of the Clean Air Act. Further, there is no single "baseline concentration" for a baseline area, due to the fact that concentrations of a pollutant vary as one moves through various locations in an area and also vary with the different meteorological conditions that occur throughout the year.

[3] Sources: For Colorado, "PSD Increment Tracking System," Colorado Department of Public Health and Environment, Updated 12/28/05, at 5. For Arizona and New Mexico, www.westar.org. For Utah, two PSD permits were issued in June of 1980 for coal-fired power plant units – Intermountain Power Plant Units 1 and 2 and Hunter Unit 3. One of these permits should have triggered the SO2 minor source baseline date in the date (if it wasn't already triggered in the state previously by another source). WESTAR incorrectly identifies the Utah SO2 minor source baseline date as April 1, 1990.

[4] The SO2 minor source baseline date is not yet triggered for the Pecos and Wheeler Peak wilderness areas.

[5] Westar incorrectly identifies the Utah SO2 minor source baseline date as April 1, 1990. In Utah, two PSD permits were issued in June of 1980 for coal-fired power plant units – Intermountain Power Plant Units 1 and 2 and Hunter Unit 3. One of these permits should have triggered the SO2 minor source baseline date in the date (if it wasn't already triggered in the state previously by another source), because these units would have been significant for SO2. Assuming it took one year after submittal of a complete PSD permit application for EPA to issue the PSD permit, that means the SO2 minor source baseline date would have been trigged in mid-1979 (or earlier if triggered by a different PSD source)

[6] As provided in the May 2004 Revised Modeling Protocol for the Proposed DREF at 7-7.

Thus, unlike the national ambient air quality standards (NAAQS), compliance with the PSD increments can generally only be assessed with air quality dispersion modeling. Further, because of the complexities of the definition of baseline concentration, the most straightforward method of assessing compliance is to model all emissions increases and decreases that affect the amount of available increment in an area and compare the modeled concentration to the applicable PSD increment. See EPA's New Source Review Workshop Manual, October 1990 Draft, at C.10.

The New Source Review Workshop Manual discusses the new sources of emissions and emissions changes at existing sources affect the amount of increment, which determines the emissions that need to be modeled to assess compliance with the increments. In general, the following emissions increases consume increment:

- actual emissions increases occurring after the major source baseline date, which are associated with physical changes or changes in the method of operation (i.e., construction) at a major stationary source; and
- actual emissions increases at any stationary, area source, or mobile source occurring after the minor source baseline date.

New Source Review Workshop Manual, October 1990 Draft, at C.10.

Further, the amount of increment available can be expanded as follows:

- Through the reduction of actual emissions after the minor source baseline date from any source that was in existence as of the minor source baseline date. The amount of increment can be added to the extent that ambient concentrations of the pollutant in question would be reduced as a result of the emission reduction.
- In addition, EPA has provided for emission reductions associated with construction at major stationary sources occurring after the major source baseline date but before the applicable minor source baseline date to "expand" the amount of available increment, in the same manner that emission increases at these sources after the major source baseline date consume the available increment. The emission reduction will add to the available increment only if the reduction is included in a federally enforceable permit or state implementation plan (SIP).

EPA's New Source Review Workshop Manual, October 1990 Draft, at C.10.

Further details on the important provisions that need to be followed in properly evaluating increment consumption will be provided later in this document in the context of a review of the cumulative Desert Rock SO_2 PSD increment analyses.

II. Review of Sithe's Cumulative Class I SO_2 Increment Analyses

Sithe provided a cumulative PSD SO_2 increment analysis for several Class I areas in its original PSD permit application submitted in May of 2004 and also submitted to EPA an updated version of the Class I area increment analysis prepared by ENSR Corporation dated January 2006. Sithe's cumulative Class I SO_2 increment analysis is seriously flawed because Sithe's improperly assumed that reductions in emissions that had occurred in the past at the nearby power plants expanded the available increment and because Sithe failed to model current maximum short term average emission rates of all of the coal-fired power plant units included in the cumulative SO_2 increment analysis. As a result, Sithe greatly underestimated SO_2 increment consumption in affected Class I areas. A detailed review and explanation is provided below.

A. Sithe Improperly Considered Emission Reductions at Nearby Power Plants as Expanding the Available SO_2 Increment

In its initial PSD permit application for Desert Rock, Sithe modeled SO_2 emission reductions that had occurred at the San Juan and Four Corners power plants in the 1970's and early 1980's as expanding the available amount of PSD increment. May 2004 Desert Rock PSD Permit Application, Attachment 6. In its updated Class I SO_2 increment analysis, Sithe modified the amount of increment expanding emissions modeled from the San Juan and Four Corners power plants, and Sithe included emission reductions at the Cameo power plant as increment expanding. January 2006 DREF Class I Area Modeling Update at 4-23 and page 2-1 of Appendix A. Sithe improperly credited SO_2 emission reductions at the Four Corners and San Juan power plants as increment expanding. With respect to the Cameo power plant, there is absolutely no discussion in either the documentation submitted by Sithe or in EPA's Ambient Air Quality Impact Report[7] (AAQIR) that was made available to the public concurrently with the proposed permit for Desert Rock.

In the 1970's and early 1980's, there were reductions in SO_2 emissions made at the San Juan and Four Corners power plants, which are located in northwestern New Mexico quite close to the proposed location of the Desert Rock power plant. In the initial May 2004 Desert Rock PSD permit application, Sithe attempted to take credit for all of those SO_2 increment reductions as expanding the available increment in its SO_2 PSD increment analyses. May 2004 DREF PSD Permit Application, Attachment 6. However, it subsequently was determined that these facilities reduced SO_2 emissions in order to comply with the SO_2 primary and secondary national ambient air quality standards (NAAQS).

Since at least 1972, there were requirements in place to reduce SO_2 emissions at the San Juan and Four Corners power plants to deal with SO_2 NAAQS compliance issues in the Four Corners Interstate region of New Mexico. Table 3 below provides the chronology of SO_2 controls in the area.

---

[7] NSR 4-1-3, AZP 04-01.

Table 3: Chronology of Federal and State Actions Regulating SO_2 Emissions from Coal-Fired Power Plants in the New Mexico Portion of the Four Corners Interstate Region

Date	Action
March 25, 1972	New Mexico adopted Section No. 602 of the Air Quality Control Regulations. Section 602.B. required that, after December 31, 1974, all existing coal burning equipment with capacity in excess of 25 MW (or 250 MMBtu/hr heat input) meet an SO_2 emission limit of 1 lb/MMBtu.
July 27, 1972	EPA disapproved the New Mexico SIP because it did not provide for attainment or maintenance of the national standards for SO_2 in New Mexico's portion of the Four Corners Interstate Region. EPA specifically disapproved New Mexico Regulation 602.B. because it did not provide for the "degree of control necessary to attain and maintain" the SO_2 NAAQS. See 37 Fed.Reg. 15086-7 (7/27/72).
March 23, 1973	EPA promulgated a federal control strategy to reduce SO_2 in the Four Corners Interstate Region. The federal regulation purportedly required 70% control at all five of the Four Corners power plant units and at Units 1 and 2 of the San Juan power plant. Compliance was required by January 31, 1974. A later compliance schedule could be approved by EPA, if it provided for compliance as expeditiously as practicable but no later than March 15, 1976. See 38 Fed.Reg. 7554-7 (3/23/73).
Between March 23 to August, 1973	Arizona Public Service (APS) filed a petition for review of EPA's regulation under section 307 of the CAA. They questioned the modeling on which the limits were based, the date of compliance, and the format of the equation used to determine the emission limit. EPA held meetings the APS (and other companies that petitioned against similar requirements promulgated concurrently by EPA for other power plants) and agreed to review the regulations. Thus, the Court stayed the petitions pending outcome of the EPA's review. See 56 Fed.Reg. 10583 (March 21 1974).
March 21, 1974	Pursuant to the petition for review by APS (and other power companies), EPA modified its SO_2 rule to allow for extension of the final compliance date to no later than July 31, 1977. The rule essentially required 70% SO_2 control on a unit-specific basis (all five units at Four Corners power plant and Unit 2 of the San Juan power plant), but it provided for approval of a plantwide limit. See 39 Fed. Reg. 10582-5 (3/21/74).
December 13, 1974	New Mexico adopted changes to rule 602.B. to require 65% SO_2 control by January 31, 1977 for those units with heat input capacity greater than 250 MMBtu/hr. For those units with heat input capacity equal to or greater than 3,000 MMBtu/hr, 85% SO_2 control was required by January 31, 1977 and 90% SO_2 control by July 31, 1979.
February 24, 1976	EPA approved New Mexico Regulation 602 as part of the State Implementation Plan (SIP) and revoked its disapproval and the SO_2 regulations for Four Corners and San Juan Power Plants. 41 Fed.Reg. 8057-8 (2/24/76).

April 6, 1976	The New Mexico Court of Appeals, pursuant to a petition brought by Public Service Company of New Mexico and Arizona Public Service Company, struck down the portions of the New Mexico Rule 602 requiring 85% and 90% control. However, the provision requiring 65% SO_2 control at all units with heat input capacity greater than 250 MMBtu/hr was kept in effect. 549 P.2d 638 (April 6, 1976).
8/17/76	Pursuant to the New Mexico court decision, EPA revoked its approval of the sections of New Mexico Rule 602 that required 85% and 90% SO_2 control. The section requiring 65% control remained in the SIP. EPA also disapproved the New Mexico SIP again for failing to provide for attainment and maintenance of the SO_2 NAAQS in the Four Corners region, but EPA did not reinstate its federal rules for controls at Four Corners and San Juan Unit 2. 41 Fed.Reg. 34749 (August 17, 1976).
1978	EPA established the New Mexico nonattainment areas pursuant to the 1977 CAA.
January 23, 1979	New Mexico submitted a SIP revision with regulations to address all of its nonattainment areas.
April 10, 1980	EPA granted conditional approval of the SO_2 SIP for the San Juan County SO_2 nonattainment area (which consisted of a 2.5 mile radius circle around the Four Corners Power plant and two nearby high altitude areas – Mesa Verde Plateau and the Hogback). According to the FR, the state has shown that the Four Corners Generating Station and the San Juan Generating Station "are the only known causes of nonattainment in these areas." Further, the state demonstrated that the primary and secondary SO_2 NAAQS would be achieved through the emission limitations specified in Regulation 602. The regulation required a final compliance date of December 31, 1982. Because the state was having subsequent public hearings on more recent ambient monitoring data, the compliance schedule for Four Corners Power Plant was delayed, so EPA only conditionally approved the SO_2 SIP pending a compliance schedule for Four Corners Power Plant. 45 Fed.Reg. 24460-24469 (4/10/80).
August 27, 1981	EPA fully approved the SO_2 SIP for San Juan County. Pursuant to a settlement agreement between New Mexico, APS, and Sierra Club, the requirements for SO_2 control at Four Corners and San Juan were revised. The regulation required a plantwide 72% control at Four Corners by the end of 1984. The Federal Register also indicated that the regulation would result in plantwide average emission rates of 0.47 lb/MMBtu for Four Corners and 0.65 lb/MMBtu for San Juan. See 46 Fed.Reg. 43152-4 (8/27/81). Notice of Proposed Approval at 46 Fed.Reg. 30653-4 (6/10/81). See also 40 C.F.R. § 52.1640(c)(22).

A copy of the EPA-approved New Mexico SO_2 regulation, as currently codified at Title 2, Chapter 2, Part 31 of the New Mexico Administrative Code (20 NMAC 2.31), is included in Enclosure 1.[8]

Emission reductions made to attain the NAAQS cannot be credited as increment-expanding. As discussed earlier, the NAAQS are the over-arching requirement that cannot be exceeded. If SO_2 baseline concentrations in the region were inflated by emissions from these power plants that were considered to be causing or contributing to SO_2 NAAQS violations, then the SO_2 emission reductions made to bring the area into compliance cannot also be used to expand the available PSD increment as this would be entirely inconsistent with the mandates of the Clean Air Act. Accordingly, Sithe updated its modeling analyses in January 2006 and Sithe did not claim increment expansion credit for those SO_2 emission reductions required to meet the NAAQS. However, Sithe has proposed to allow for increment expansion for those emission reductions at San Juan Units 1 and 2 and at the Four Corners power plant that went beyond what Sithe determined was necessary to meet the short term average SO_2 NAAQS.

Although there were federally required SO_2 emission reduction requirements in place as early as 1972, the Four Corners power plant did not upgrade or install SO_2 pollution controls to reduce its SO_2 emissions until the early 1980's. The SO_2 controls at San Juan Units 1 and 2 were not operational until April and June of 1978, respectively.[9]

There are numerous errors and unsupported assumptions in Sithe's methods used to determine the level of control that was necessary to meet the NAAQS and its determination that increment-expanding emissions exist from Units 1 and 2 of the San Juan Power Plant and the Four Corners Power Plant. The following discussion describes the legal and technical issues associated with Sithe's claim of increment-consuming emissions from Units 1 and 2 of the San Juan power plant and from all five units at the Four Corners power plant.

1. The Allowable Emissions of San Juan Units 1 and 2 as of the Applicable Baseline Date Must Be Considered in Determining the Baseline SO_2 Emissions from these Units for Increment Assessments in Colorado and Arizona Class I Areas

As discussed above, the SO_2 controls were not operational at San Juan Units 1 and 2 until April and June of 1978, respectively. See Enclosure 10. According to the Application for Authority to Construction San Juan Unit 1, received by the state of New Mexico on May 18, 1973, Unit 1 was to be designed with a scrubber to reduce SO_2 emissions by 79.2% control (included as Enclosure 3 to this report). This unit was approved for construction with SO_2 controls achieving 79.2% control. *Id.* Construction of Unit 1 of

[8] As downloaded from the EPA Region VI internet site on 10/24/06.

[9] As discussed in the July 14, 1978 transcript of proceedings In The Matter Of: The Variance Request of the Public Service Company of New Mexico for its San Juan Coal-Fired Generating Unit No. 3 For A Variance Through May 1, 1982, before the New Mexico Environmental Improvement Board, Sante Fe, New Mexico, at 11. Relevant excerpts of this transcript are provided in Enclosure 10.

the San Juan Power Plant commenced in 1974 and the unit began operating in December of 1976.[10] San Juan Unit 2 went into commercial operation in 1973.[11] Thus, it was an existing source as of the major source baseline date. PNM's October 15, 1973 Certificate of Registration indicated that it would install SO_2 controls of 79% SO_2 control by July 31, 1977.[12]

It appears that San Juan Unit 1 may have been operated for a short time without SO_2 controls, and San Juan Unit 2 clearly operated for some time without SO_2 controls. For some areas – Colorado and Arizona in particular, this means that these units reduced SO_2 emissions after the SO_2 minor source baseline date. For New Mexico and Utah, it appears these SO_2 reductions occurred before the applicable SO_2 minor source baseline date. See Table 2 above.

However, it also appears that construction may have commenced on the SO_2 controls at these units prior to the applicable SO_2 major source baseline date of January 6, 1975.[13] For example, in the May 9, 1975 Minutes of the Meeting of the Environmental Improvement Board of New Mexico, it is stated that PNM "is continuing with its SO_2 removal contracts and is not delaying any action as a result of the appeal" of the New Mexico SO_2 regulations by Arizona Public Service (APS). (Enclosure 5). This statement strongly implies that PNM already had contracts in place for SO_2 controls at San Juan Units 1 and 2. Further, in a July 14, 1978 hearing before the New Mexico Environmental Improvement Board, a PNM representative stated that they had "been in the evaluation, design, engineering, and construction process for SO_2 removal systems since 1972" and that they selected a system of SO_2 removal in February of 1974.[14] Thus, it seems that PNM could have been considered to have "commenced construction" on the modifications to reduce SO_2 emissions at San Juan Units 1 and 2 by the entering into "binding agreements or contractual obligations that could not be cancelled or modified without substantial loss" before the SO_2 major source baseline date of January 6, 1975 See 40 C.F.R. §52.21(b)(9). For those areas with SO_2 minor source baseline dates triggered prior to April and June of 1978 (which includes Colorado and Arizona as provided in Table 2 above), this would mean that the allowable emissions of these units would be considered part of the baseline concentration. See 40 C.F.R. §52.21(b)(13)(i)(b). The allowable emissions would be based on the most stringent of the emission limits in a federally enforceable permit or the SIP "including those with a future compliance date," or in the New Source Performance Standards (NSPS). See 40 C.F.R. §52.21(b)(16).

Even if construction on the SO_2 controls at these units was not considered to have commenced prior to the SO_2 major source baseline date, the allowable SO_2 emissions of these units should have been considered part of the baseline concentration because these

[10] See Construction Schedule for Unit 1 at San Juan Station, January 1975, attached to February 25, 1975 letter from Public Service Company of New Mexico to the New Mexico Environmental Improvement Agency (Enclosure 4).
[11] October 15, 1973 letter and its "Application for Certification of Registration" (Enclosure 2) at page 1.
[12] *Id.* at page 2.
[13] See 40 C.F.R. §52.21(b)(14)(i)(a).
[14] See Enclosure 10 at 12, 11.

units were operating out of compliance with permitted SO_2 emission requirements and with the federally-approved SIP that was in effect between December of 1976 and February/April of 1978 (i.e., both San Juan Units 1 and 2) when the applicable minor source baseline dates were triggered in Colorado and Arizona (i.e., of October 1977). The federally enforceable construction permit for San Juan Unit 1 included a requirement for installation of SO_2 controls of 79.2% control. See Enclosure 3. Under the EPA-approved SIP that was in effect during that time, San Juan Unit 1 was subject to a 0.34 lb/MMBtu SO_2 emission limit and San Juan Unit 2 was required to meet 65% control.[15] The regulation does not indicate the averaging time of these emission limits, but the information to be submitted to show compliance is based on hourly or daily averages. As discussed in EPA's August 7, 1980 PSD rulemaking, for sources with source-specific allowable emission limits in the SIP, such as for the San Juan power plant, it should be assumed that the source's actual emissions equal the source's allowable emissions.[16] In part, EPA's rationale for this position is that it "maintains the integrity of the PSD and NSR systems and the SIP process."[17]

Thus, for all of the above reasons, the allowable emissions (as required at the time of the applicable SO_2 minor source baseline dates in Colorado and Arizona) must be considered in determining the baseline emissions of San Juan Units 1 and 2 for the SO_2 increment assessments performed for Colorado and Arizona Class I areas.

2. The Actual Emissions of San Juan Units 1 and 2 as of the Applicable Baseline Date Must Be Considered in Determining the Baseline SO_2 Emissions from These Units for Increment Assessments in New Mexico and Utah

Because the SO_2 controls were put into place at San Juan Units 1 and 2 before the applicable SO_2 minor source baseline dates in New Mexico and Utah (see Table 2 above), the actual emissions from San Juan Units 1 and 2 must be considered in determining the baseline SO_2 Emissions from these units. There is some difficulty in doing this because it does not appear that these units had continuous emission monitors operating for SO_2 at that time. However, there is sufficient information available to indicate that, prior to the applicable New Mexico and Utah SO_2 minor source baseline dates (i.e., October 1978 in San Juan County (for the Class II increment), May 1981 in nearby New Mexico Class I areas, and probably in 1979 in Utah (see Table 2 above)) San

[15] See December 13, 1974 New Mexico Environmental Improvement Board Air Quality Control Regulation Number 602, which was approved by EPA at 41 Fed.Reg. 8057-8 (February 24, 1976) and modified at 41 Fed.Reg. 34749 (August 17, 1976) to remove approval of 85% and 90% SO2 control requirements. A copy of the December 13, 1974 regulation is included as Enclosure 11.

[16] 45 Fed.Reg. 52676 (August 7, 1980). See also discussion in 8/7/80 Federal Register in which EPA states that emissions allowed under SIP relaxations pending EPA approval as of August 7, 1977 can be included in the baseline "if the allowed source emissions were higher than actual emissions." For similar reasons then, if an EPA-approved SIP in effect as of the minor source baseline date requires lower emissions than is actually being emitted, the lower allowable emission rate must be considered part of the baseline concentration and any increases over that rate would consume increment. In addition, SIP relaxations after the baseline data consume the increment based on the emissions allowed under the revised SIP.

[17] *Id.*

Juan Units 1 and 2 may have been reducing SO_2 to levels lower than their allowable emission rates.

That information includes the following:

1) PNM intended to operate the controls to achieve greater reductions than required by regulation as a margin of compliance. See February 25, 1975 letter from PNM to New Mexico at 2. (Enclosure 4). Indeed, PNM intended to meet 90% SO_2 control for a margin of safety and they intended to meet that level of control by 12/77. See discussion in "draft" New Mexico Environment Department document entitled "Four Corners Timeline for SO_2 Regulation Development" at 5 (describing hearings at the New Mexico Environmental Improvement Board (EIB) in August 1977 to determine percent SO_2 control to meet the NAAQS), Enclosure 7. See also discussion in Enclosure 10 at 11 in which PNM states that the SO_2 controls at San Juan Units 1 and 2 were designed to achieve 90% SO_2 control.

2) Although no emissions data is readily available for 1977, a review of the historical SO_2 emissions data available on EPA's Clean Air Markets website shows that in 1980, San Juan Units 1 and 2 appear to have been controlling SO_2 to roughly 90% on an annual basis (based on a determination of uncontrolled SO_2 emission exiting the boiler from data submitted with their permit applications). By 1985 (when the New Mexico and federally approved regulatory requirements had been relaxed from what was previously required from 1973 on), the level of SO_2 control decreased.

Specifically, the uncontrolled SO_2 emissions rate from the San Juan Units 1 and 2 boilers (i.e., reflecting that portion of the sulfur that falls out in the bottom ash) based on information provided in their 1973 submittals to New Mexico (see Enclosures 2 and 3) would be 1.43 lb/MMBtu.[18] Table 4 below shows excerpts from EPA's "Emission Scorecard"[19], which shows annual SO_2 emissions and annual heat input for 1980 and 1985 for San Juan Units 1 and 2. With this data, annual average SO_2 emission rates were calculated and presented in the table.

[18] This uncontrolled SO2 emission rate was calculated using AP-42 emission factors (from Table 1.1-3 of AP-42 Chapter 1.1) and PNM's coal specifications submitted with their 1973 permit application/certification of registration for San Juan Units 1 and 2 (Enclosures 3 and 2, respectively) of 9,800 Btu/lb heating value and 0.8% sulfur content. Based on this data and emissions factor from AP-42, the uncontrolled SO2 emissions exiting the boiler would be 1.4286 lb/MMBtu.
[19] Available at EPA's Clean Air Markets Database website, at http://www.epa.gov/airmarkets/data.html#emissions.

Table 4: 1980 and 1985 SO_2 Emissions at San Juan Units 1 and 2

San Juan Unit	1980 SO_2	1980 Heat Input, MMBtu	1980 SO_2 Emission Rate, lb/MMBtu (annual average)	1985 SO_2, tons	1985 Heat Input, MMBtu	1985 SO_2 Emission Rate, lb/MMBtu (annual average)
1	1,442	19,463,698	0.148	8,862	27,240,000	0.651
2	1,462	19,599, 201	0.149	5,954	25,770,000	0.462

Source: EPA "Emissions Scorecard."

> Comparing to an uncontrolled SO_2 emission rate calculated as discussed above of 1.43 lb/MMBtu, it appears that San Juan Units 1 and 2 were achieving 89-90% SO_2 control in 1980, but then this level of control was reduced to 67% SO_2 at San Juan Unit 2 and 54.4% SO_2 control at San Juan Unit 1 on an annual average basis in 1985.[20]

Further, it seems that San Juan Units 1 and 2 were actually emitting SO_2 at lower annual average SO_2 emission rates in 1980 than in 2005. Specifically, based on emissions data from EPA's preliminary summary emission report for 2005[21] available on EPA's Clean Air Markets Database website, San Juan Unit 1 was emitting at 0.217 lb/MMBtu on an annual average and San Juan Unit 2 was emitting SO_2 at 0.207 lb/MMBtu on an annual average basis.[22] Clearly, if these units were actually operating at lower SO_2 emission rates at the time of the applicable SO_2 minor source baseline date than current SO_2 emission rates, there would be no increment expanding emissions from these two units and, instead, there may be SO_2 increment consuming emissions from these two units. As discussed above, there is much information available to indicate that San Juan Units 1 and 2 *were* emitting less at the time of the New Mexico and Utah SO_2 minor source baseline dates than currently. Consequently, rather than considering the emission reductions at these units that occurred almost 30 years ago as expanding the available increment, Sithe should have determined the *increment-consuming* actual emission increases that have occurred at these two units since the time of the applicable New Mexico and Utah SO_2 minor source baseline dates.

[20] Note that if sulfur content of the coal increased such that uncontrolled SO2 emissions were higher in 1985 than represented by PNM in 1973, then the 1985 annual average emission rates could reflect a greater level of SO2 than 67% at San Juan Unit 2 and 54% at San Juan Unit 1. But it still appears likely that SO2 emissions at San Juan Units 1 and 2 were being controlled to a greater degree in 1980 than in 1985.
[21] Available at http://www.epa.gov/airmarkets/emissions/prelimarp/index.html.
[22] Based on 2005 SO2 emissions of 2,823 tons and 2005 heat input of 25,973,412 MMBtu for San Juan Unit 1, and 2005 SO2 emissions of 2,540 tons and 2005 heat input of 24,501,834 MMBtu.

3. The Allowable Emissions of the Four Corners Power Plant Units as of the Applicable Baseline Date Must Be Considered in Determining the Baseline SO_2 Emissions from these Units

As discussed above, the SO_2 controls at the Four Corners Power Plant units were not operational until the early 1980's, after the SO_2 minor source baseline dates for all areas of consideration in the DREF PSD increment analyses. However, as discussed above, the Four Corners Power Plant was subject to SO_2 emission reduction requirements at the time of the applicable SO_2 minor source baseline dates. For the reasons discussed in Section II.A.1. above, the allowable SO_2 emissions of these units should have been considered part of the baseline concentration because these units were operating out of compliance with permitted SO_2 emission requirements and with the federally-approved SIP that was in effect at the time of the applicable SO_2 minor source baseline dates.

For the Colorado, Utah, and Arizona Class I areas and in San Juan County, New Mexico, in which the SO_2 minor source baseline dates were triggered prior to April of 1980 (see Table 2 above), the EPA-approved SIP that was in effect during that time required all of the Four Corners units to meet 65% control.[23] The regulation does not indicate the averaging time of these emission limits, but the information to be submitted to show compliance is based on hourly or daily averages. For the New Mexico Class I areas (San Pedro Parks Wilderness Area, Bandelier National Monument) in which the SO_2 minor source baseline date was triggered in May of 1981, the SIP as approved by EPA in April of 1980 required the Four Corners Power Plant to meet an SO_2 emissions limit of 0.53 lb/MMBtu.[24]

Thus, for all of the above reasons, the allowable emissions as required at the time of the applicable baseline date must be considered in evaluating the baseline emissions of the Four Corners Power Plant.

4. Sithe and EPA Region IX Improperly Determined the Level of Control Deemed Necessary to Attain the SO_2 NAAQS at San Juan Units 1 and 2 and at the Four Corners Power Plant

As discussed above, Sithe cannot take increment expansion credit for the installation of controls at San Juan Units 1 and 2 or at the Four Corners Power plant because the reductions were necessary to attain the SO_2 NAAQS. Thus, in addition to reviewing the actual or allowable emissions at the time of the applicable baseline date as discussed above, a review of the emission rates necessary to attain the SO_2 NAAQS must be done to determine the appropriate baseline emissions for each of the power plant units in

[23] See December 13, 1974 New Mexico Environmental Improvement Board Air Quality Control Regulation Number 602, which was approved by EPA at 41 Fed.Reg. 8057-8 (February 24, 1976) and modified at 41 Fed.Reg. 34749 (August 17, 1976) to remove approval of 85% and 90% SO2 control requirements. A copy of the December 13, 1974 regulation is included as Enclosure 11.

[24] See June 9, 1978 New Mexico Environmental Improvement Board Air Quality Control Regulation Number 602, which was approved by EPA at 45 Fed.Reg. 24460 (April 10, 1980). A copy of the June 9, 1978 regulation is included as Enclosure 12.

question. However, Sithe and EPA improperly determined the level of control that was considered necessary to meet the NAAQS at San Juan Units 1 and 2 and at the Four Corners Power Plant.

To determine what was necessary to attain the SO_2 NAAQS at the San Juan and Four Corners power plants, Sithe relied on a discussion in the preamble to the 6/10/81 Federal Register notice stating that "[p]lant-wide average SO_2 emissions will be 0.47 lb/MMBtu for the Four Corners plant and 0.65 lb/MMBtu for the San Juan plant after 1984."[25] Because these emission levels applied on longer term average[26], Sithe presumed that peak SO_2 emission rates from these units on a short term average would be much higher.[27] Specifically, Sithe first determined the allowable hourly SO_2 emissions rates by multiplying the heat input capacity of each these allowable emission rates[28], as follows:

Table 5: Sithe's Estimate of Hourly SO_2 Emission Rates Under the Requirements of the EPA-Approved SIP

Unit	Hourly Heat Input Capacity	Allowable SO_2 Emission Rate, lb/MMBtu	Allowable SO_2 Emissions, lb/hr
San Juan Unit 1	3,310	0.65	2,151.5
San Juan Unit 2	3,310	0.65	2,151.5
Four Corners Unit 1	1,710	0.47	803.7
Four Corners Unit 2	1,710	0.47	803.7
Four Corners Unit 3	2,030	0.47	954.1
Four Corners Unit 4	7,034	0.47	3,306
Four Corners Unit 5	7,034	0.47	3,306

Sithe assumed that because these SIP emission limits applied on a 30 –day average basis, it was appropriate to determine peak short term SO_2 emission rates from these units. To determine what the peak short term SO_2 emissions might be from these units, Sithe

[25] 46 Fed.Reg. 30653, as cited in Appendix A of the Desert Rock Energy Facility Application for Prevention of Significant Deterioration Permit - Class I Area Modeling Update, January 2006, at A-1.
[26] It appears that the reference in the June 10, 1981 Federal Register to a plantwide emissions level at San Juan power plant of 0.65 lb/MMBtu was derived from 20 NMAC 2.31.109.D. (as currently codified in the New Mexico SIP) that includes a 30-day average SO2 emission limit of 0.65 lb/MMBtu. Similar, 20 NMAC 2.31.110.B.1. includes a requirement applicable to the Four Corners Power Plant to reduce SO2 emissions by 72% on a 30 day average.
[27] Sithe performed Class I cumulative SO2 increment analyses only for the short term average SO2 increments – i.e., the 3-hour and 24-hour average SO2 increments. Thus, when Sithe used the 30-day average plantwide SO2 emission limit as defining the level necessary to attain the SO2 NAAQS, Sithe assumed that maximum 3-hour and 24-hour SO2 emission rates at these units would likely be much higher because the units could occasionally operate at higher rates and still show compliance with an emission limit that is averaged over a 30-day period (i.e., a long term average limit).
[28] As shown in the spreadsheet "CALPUFF Modeling Background SO2 Inventory by ENSR.xls" which was provided to the author by Scott Bohning of EPA Region IX in an email dated 10/19/06. A copy of this spreadsheet is included as Enclosure 6 to this report.

multiplied the above lb/hr values in Table 3 by a ratio of "peak"[29] to mean hourly emission rates determined to occur at these units in 2003 and 2004. Desert Rock Energy Facility Application for Prevention of Significant Deterioration Permit - Class I Area Modeling Update, January 2006, at A-1. Those hourly emission rates were then considered the peak short term average emission rates for each unit that were necessary to attain the short term average SO_2 NAAQS. And that is also the level of emissions that Sithe considered as reflecting baseline emissions at Units 1 and 2 of the San Juan Power Plant.

However, Sithe's approach is greatly in error and is inconsistent with PSD regulations and guidance for several reasons as follows:

a) Sithe's Method of Determining Peak Hourly Emission Rates Is Inconsistent with the NAAQS Demonstration for the 1981 New Mexico SO_2 SIP

As described earlier, Sithe increased the emission rates derived from the June 10, 1981 Federal Register preamble by a ratio of "peak" to mean hourly emission rates. Thus, rather than assuming that the SO_2 emission rates calculated in accordance with the information in the June 10, 1981 EPA rulemaking, Sithe greatly increased the hourly emissions to reflect its determination of the emission rates considered necessary to attain the 3-hour and 24-hour average SO_2 NAAQS. Specifically, Sithe took the results shown above in Table 3, and multiplied the data by the ratio of the 99th percentile actual hourly SO_2 emission rate to the mean actual hourly emission rate based on actual continuous emission monitoring (CEM) data for San Juan Units 1 and 2 and all of the Four Corners Power Plant units. Sithe evaluated actual acid rain program SO_2 emissions data from these units that occurred during 2003 and 2004, determined the 99th percentile hourly value for each year and then averaged those 99th percentile values. A similar approach was used to obtain an average mean hourly SO_2 emission rate for each unit.[30] Consequently, Sithe modified the hourly emission rates presented in Table 3 above as follows:

[29] Sithe used the 99th percentile hourly emission rate, rather than the true maximum hourly emission rate. See Enclosure 6.

[30] The above discussion is based on the 12/5/05 email from Bob Paine, ENSR, to Scott Bohning, EPA Region 9, with subject "Desert Rock Class I Cumulative Inventory" or was determined from a review of the spreadsheet with filename "CALPUFF Modeling Background SO2 Inventory by ENSR.xls." Both of these documents were obtained by the author from Scott Bohning of EPA Region 9.

Table 6: Sithe's Determination of Maximum Hourly SO_2 Emission Rates Occurring in 1984[31]

Unit	Allowable SO_2 Emissions, lb/hr Based on 1981 FR	2003-2004 Average 99th Percentile/ Mean	Estimated Max lb/hr 1984
San Juan Unit 1	2,151.5	1.96	4,223.8
San Juan Unit 2	2,151.5	1.84	3,964.9
Four Corners Unit 1	803.7	2.37	1,906.5
Four Corners Unit 2	803.7	2.03	1,633.4
Four Corners Unit 3	954.1	2.60	2,481.1
Four Corners Unit 4	3,306	1.53	5,054.1
Four Corners Unit 5	3,306	1.44	4,763.4

However, it does not appear that Sithe researched the New Mexico SO_2 SIP to determine what was considered necessary to attain the SO_2 NAAQS in San Juan County, New Mexico. Further, San Juan Unit 2 is also subject to a 72% SO_2 removal requirement pursuant to 20 NMAC 2.31.110.A. of the approved New Mexico SIP in addition to the 0.65 lb/MMBtu plantwide SO_2 limit, and the 72% control requirement requires a more stringent emission rate at San Juan Unit 2 than at the other San Juan units. Specifically, 72% control at San Juan Unit 2 would result in an emission rate of 0.40 lb/MMBtu.[32] Sithe also used incorrect maximum heat input capacity data for San Juan Units 1 and 2. The correct heat input capacities of San Juan Units 1 and 2 are 3,240 and 3,155 MMBtu/hr, respectively.[33]

The most important issue here is to determine the emission rates that were deemed necessary to comply with the NAAQS in the 1981 New Mexico SO_2 SIP. It appears that Sithe assumed that, because the 72% control requirement at Four Corners and the 0.65 lb/MMBtu SO_2 limit at San Juan both applied on 30-day averages, these power plant units were modeled at higher SO_2 emission rates in the state of New Mexico's demonstration of compliance with the 3-hour and 24-hour average SO_2 NAAQS. However, a review of the historical SIP documents on file with EPA Region 6 shows that this was not the case. Although the 72% control requirement and the 0.65 lb/MMBtu emission limits applied on 30-day averaging times,

---

[31] This data is from the worksheet entitled "SO2 Expansion" in the spreadsheet with file name "CALPUFF Modeling Background SO2 Inventory by ENSR.xls." (Enclosure 6).

[32] Seventy-two percent control of an SO2 emission rate exiting the boiler of 1.4286 lb/MMBtu equals 0.4 lb/MMBtu. See footnote 18 which explains how the uncontrolled SO2 emissions exiting the boiler were estimated.

[33] These heat input capacities used in this table were those reported as "normal conditions of operation" in a 2/25/75 letter from PNM to New Mexico. Enclosure 4 at page 3.

emission rates consistent with these emission limitations are what was modeled to show attainment of the 24-hour and 3-hour average SO_2 NAAQS. A February 4, 1981 document entitled "Control Strategy Demonstration: New Mexico Air Quality Control Regulation 602, Coal Burning Equipment –Sulfur Dioxide" and a February 13, 1981 supplement to this document, both prepared by the New Mexico Environmental Improvement Division for EPA Region 6 make this clear.[34]

Specifically, to demonstrate attainment of the 24-hour and 3-hour average SO_2 NAAQS after 1984 when all of the Four Corners units were to be in compliance with the 72% SO_2 removal requirement, New Mexico modeled a "Scenario 2A" which included all Four Corners units and San Juan Unit 2 at 72% control and San Juan Units 1, 3, and 4 at 0.55 lb/MMBtu (which was updated in the February 13, 1981 supplement to reflect the 0.65 lb/MMBtu SO_2 limit that the New Mexico SO_2 regulation allowed the San Juan units 1,3 and 4 to increase to).[35] New Mexico stated that Scenario 2A "is a reasonable worst case, not only because all nine units at the two plants are assumed to be at full load on a continuous basis, but also because for Four Corners about 80% of the time short term removal efficiencies will be greater than 82%."[36] New Mexico also modeled a "Scenario 2B – Four Corners at 17,900 lb/hour distributed to each unit in proportion to its load capacity, and San Juan at 13,000 lb/hr distributed in accordance with load capacity."[37] The 17,900 lb/hr limit and the 13,000 lb/hr limit are plantwide 3-hour average emission limits that were included in the New Mexico regulation 602 as revised on November 24, 1980 in 602.B.2.b. and 602.A.6., respectively. A copy of the November 24, 1980 New Mexico rule is included as Enclosure 14. New Mexico further stated "[s]cenario 2B can be thought of as an absolute worst case for each plant. Each plant has an extremely low probability of exhibiting this level of emissions. . .with a vanishingly small probability of the simultaneous occurrence of these levels at each plant."[38] EPA's proposed and final rulemakings on the revised New Mexico plan for attainment of the SO_2 primary and secondary NAAQS in San Juan County do not discuss these 3-hour average plantwide caps. Instead the discussion of the SO_2 control strategy focuses on the 72% control requirement and the plantwide average emission rates of 0.47 lb/MMBtu for the Four Corners Power Plant and of 0.65 lb/MMBtu for the San Juan Power Plant.

---

[34] Relevant excerpts of the February 4, 1981 document and the February 13, 1981 supplement are included as Enclosure 13 to this report.

[35] See February 4, 1981 document entitled "Control Strategy Demonstration: New Mexico Air Quality Control Regulation 60, Coal Burning Equipment –Sulfur Dioxide" prepared by the New Mexico EID, at 3-9 to 3-10. See also the February 13, 1981 supplement to the February 4, 1981 document at 25-30. Enclosure 13.

[36] See February 4, 1981 document entitled "Control Strategy Demonstration: New Mexico Air Quality Control Regulation 60, Coal Burning Equipment –Sulfur Dioxide" at 3-10. (Enclosure 13).

[37] *Id.*

[38] *Id.*

See 46 Fed.Reg. 30654 (June 10, 1981).[39] Thus, clearly, the emissions modeled as Scenario 2A were what was adopted as necessary to attain the 24-hour and 3-hour SO_2 NAAQS, and the fact that the emission limits applied on a 30-day average basis is irrelevant with respect to what was modeled to show attainment of the NAAQS. Consequently, Sithe's approach to increase the 30-day average emission rates to reflect peak hourly emissions is significantly flawed and improperly inflated what Sithe considered to be the baseline emissions from these units above the levels deemed necessary to attain the SO_2 NAAQS.

It is also important to note that the New Mexico's modeling did not show attainment of the 3-hour average SO_2 NAAQS with the modeling of Scenario 2B – i.e., the modeling of the 3-hour average plantwide caps applicable at the San Juan and Four Corners Power Plants. Specifically, the February 4, 1981 modeling report indicates that the "calculated high second high 3-hour value for the 1977 data year is 1626 $\mu g/m^3$," and then the state provided a probability analysis of the likelihood of this actually occurring to justify the modeling results.[40]

Indeed, it appears that additional modeling should be done to determine what emissions rates at San Juan and Four Corners Power Plants are necessary to attain the 24-hour and 3-hour average SO_2 NAAQS. That is because EPA had major concerns with the non-guideline model used by New Mexico in its attainment demonstration. For example, the July 23, 1981 EPA Action Memorandum for the approval of the New Mexico SIP as revised and submitted to EPA in November of 1980 indicates that "the modeling for high terrain (where violations of the standards would most likely be expected) is not considered appropriate. In fact, no appropriate dispersion modeling techniques for the high terrain in San Juan County presently exists."[41] EPA went on to state "[t]herefore, our acceptance of the State's control strategy demonstration on the high terrain is a judgment that the primary standards will not be exceeded after 1982, and the secondary standard will not be exceeded after 1984. This judgment is based on the available air quality data, dispersion modeling which identifies the locations of expected high SO_2 concentrations, and the emission reductions provided by the revised regulation."[42] Modeling techniques have significantly advanced since 1981. Thus, it makes most sense to use current EPA-approved modeling techniques to verify whether the emission limits of the 1981 New Mexico SIP are still considered

[39] It must be noted that EPA failed to mention that San Juan Unit 2 is also subject to a 72% control requirement which is more restrictive than the 0.65 lb/MMBtu emission limit applicable to the entire plant. See section 602.B.2.a. of the 1980 New Mexico SO2 rule that was approved by EPA on August 27, 1981 in Enclosure 14.

[40] *Id.* at 7-8 to 7-10.

[41] July 23, 1981 Memorandum from Frances E. Phillips, Acting Regional Administrator, to Anne M. Gorsuch, Administrator of EPA, at 2. (Enclosure 15).

[42] *Id.*

adequate to demonstrate attainment of the SO_2 NAAQS, especially before allowing a source such as the DREF to rely on emission reductions at the San Juan and Four Corners Power Plants to expand the increment and make way for DREF's contribution to SO_2 concentrations in the area.

Consequently, at the minimum, the short term average emission rates considered necessary by New Mexico to attain the NAAQS should have been those shown in Table 7. For comparison, the peak hourly emission rates that Sithe calculated are also shown in Table 7.

Table 7. SO_2 Emissions Rates Under the 1981 New Mexico SO_2 SIP to Attain the Primary and Secondary SO_2 NAAQS[43]

Unit	Hourly Heat Input Capacity	Allowable SO_2 Emissions Modeled in 1981 to Demonstrate Attainment of 3-hour and 24-hour SO_2 NAAQS, lb/hr	Sithe's Approach to Determining Estimated Maximum lb/hr SO_2 Emissions in 1984
San Juan Unit 1	3,240	2,106	4,223.8
San Juan Unit 2	3,155	1,262	3,964.9
Four Corners Unit 1	1,710	804	1,906.5
Four Corners Unit 2	1,710	804	1,633.4
Four Corners Unit 3	2,030	954	2,481.1
Four Corners Unit 4	7,034	3,306	5,054.1
Four Corners Unit 5	7,034	3,306	4,763.4

As Table 7 makes clear, Sithe's approach overestimated the level of emissions considered necessary to attain the SO_2 NAAQS.

[43] These allowable emission rates were based on an emission rate of 0.65 lb/MMBtu at San Juan Units 1,3 and 4, 72% control or 0.40 lb/MMBtu at San Juan Unit 2, and 72% control or 0.47 lb/MMBtu (as discussed in the June 10, 1981 Federal Register notice, 46 Fed.Reg. 30653) at Four Corners Units 1-5. For San Juan Unit 2, no emissions rate is indicated in the EPA's June 10, 1981 Federal Register notice. A review of the EPA-approved regulation indicates that the seventy-two percent control requirement applies to the SO2 emissions exiting the boiler (see section 602.B.2.a. of the 1980 New Mexico SO2 rule that was approved by EPA on August 27, 1981 in Enclosure 14). Footnote 18 discusses how the uncontrolled SO2 emissions exiting the boiler were determined to be 1.4286 lb/MMBtu based on AP-42 emission factors. Thus, 72% control from 1.4286 lb/MMBtu equals 0.40 lb/MMBtu.

b) Sithe's Approach to Determining Peak Short Term Emission Rates Would Provide for Baseline Emission Rates at the San Juan Power Plant in Excess of the Allowable Emissions Under the SIP

Sithe's approach to estimating peak short term emission rates is also flawed for the San Juan Power Plant because it essentially resulted baseline emission rates that would not be allowed under the SIP. Specifically, if one applies Sithe's approach of relying on the 0.65 lb/MMBtu plantwide limit and multiplying by the "peak" to mean ratio as described above to all four of the San Juan units, then the total hourly emissions would be greater than the 3-hour allowable plantwide cap as shown in Table 8. Specifically, the total hourly SO_2 emission rates at San Juan Power Plant using Sithe's approach would be 19,831 lb/hr as compared to the SIP short term average limit of 13,000 lb/hr. This shows another flaw in Sithe's method to determining baseline emissions, in addition to the issues described above on what was modeling in 1981 to show attainment of the SO_2 NAAQS.

Table 8: Sithe's Approach to Determining the Peak Short Term SO_2 Emission Rates Applied to All Four Units at San Juan Power Plant

San Juan Unit	Heat Input Capacity, MMBtu[44]	SO_2 Emissions (at 0.65 lb/MMBtu), lb/hr	'03-'04 ratio of 99^{th} percentile hourly emission rate/mean emission rate	Sithe's Estimated Max Hourly SO_2 Emission Rate, lb/hr
1	3240	2106	1.97	4148.8
2	3155	2050.8	1.84	3773.4
3	5295	3441.8	1.79	6160.7
4	5295	3441.8	1.67	5747.7
			Total =	19,831 lb/hr

c) Sithe's Approach to Determining Peak Short Term Emission Rates at the Four Corners Power Plant Is Also Flawed Because of the Lack of Any Enforceable SO_2 Emission Limits Over the Past Several Years

It is also important to note that the Four Corners Power Plant has not been subject to *any* enforceable emission limits on SO_2 since EPA determined the source was in Indian country and not under New Mexico jurisdiction (which was at least since 1999). Thus, an evaluation of current average and current "peak" emission rates when the facility was not subject to any enforceable emission limits cannot be considered as telling to how the

[44] Note that Sithe used slightly different heat input capacities for Units 1 and 2. These heat input capacities used in this table were those reported as "normal conditions of operation" in a 2/25/75 letter from PNM to New Mexico. Enclosure 4 at page 3.

plant was operated in 1984 when the owner and operator thought they were subject to state and federally enforceable SO_2 emission limits. Thus, this is another flaw in Sithe's approach to determining peak hourly emission rates, in addition to the issues with what emission rates at the Four Corners Power Plant were modeled to demonstrate attainment of the SO_2 NAAQS as discussed above and in the next section.

d) EPA Must Determine the Level of SO_2 Control at Four Corners Power Plant Considered Necessary to Attain the Short Term Average SO_2 NAAQS

Although EPA approved the New Mexico SIP in 1981 which included specific SO_2 emission limits for the Four Corners Power Plant (46 Fed.Reg. 43152-4, August 27, 1981), it was later determined that the state of New Mexico did not have authority to regulate the air quality emissions from the Four Corners Power Plant because it is located on Navajo Nation lands. Consequently, EPA has proposed – twice over the last 7 years – a federal implementation plan (FIP) for the Four Corners Power Plant. This FIP has not yet been promulgated to date. EPA's most recent proposed FIP for the Four Corners Power Plant includes a 3-hour average plantwide cap of 17,900 lb/hr and an 88% SO_2 plantwide control requirement that applies on a yearly basis (71 Fed.Reg. 53636, September 12, 2006). The short term average limit is the same as the short term average SO_2 limit applicable to the Four Corners power plant in the EPA-approved New Mexico SIP.[45] As discussed above, New Mexico did not adequately demonstrate that this limit, in conjunction with modeling the San Juan power plant at its 13,000 lb/hr 3-hour average plantwide cap, would ensure attainment of the 3-hour SO_2 NAAQS. It is also interesting to note that EPA has dropped the previously applicable New Mexico plantwide 72% control requirement that applied on a 30-day average basis and that, as discussed above, was apparently relied upon to demonstrate compliance with the 3-hour and 24-hour average SO_2 NAAQS. While the 88% SO_2 control requirement is more restrictive than 72% control, it applies on a longer averaging time. Further, it's possible that the sulfur content of the coal has increased since 1981. Thus it's not clear what emission rate is reflective of 88% control and whether EPA's proposal is as stringent as what was required at Four Corners under the 1981 New Mexico SIP.

EPA should have done a modeling analysis to justify any measures it was approved as part of a FIP as sufficient to attain or maintain the SO_2 NAAQS. Therefore, if not already completed, EPA conduct such modeling and ensure that its FIP for Four Corners Power Plant sets enforceable emission limits that are sufficient to ensure attainment and maintenance of the short term SO_2 NAAQS. If that modeling has been

[45] See 20 NMAC 2.31.110.B.2., Enclosure 1.

completed for the Four Corners Power Plant FIP, EPA must review that modeling analysis to determine the appropriate 3-hour and 24-hour SO_2 emissions rates that can be considered the minimum level of control necessary to meet the SO_2 NAAQS at Units 1-5 of the Four Corners Power Plant for the cumulative DREF SO_2 PSD increment analyses

With EPA's proposed Four Corners FIP and the lack of a demonstration that the 17,900 lb/hr 3-hour cap would provide for attainment of the SO_2 NAAQS, deriving the emission rates for the Four Corners Power Plant that are necessary to assure attainment of the SO_2 NAAQS is an impossible exercise. EPA should not allow Sithe to assume anything about what emission rates were necessary at the Four Corners Power Plant to provide for attainment of the SO_2 NAAQS until EPA provides a demonstration of NAAQS compliance for its FIP for the Four Corners Power Plant.

5. What Are the Appropriate Short Term Average SO_2 Emissions Rates to Be Considered as Reflecting Baseline Emissions At San Juan Units 1 and 2 and the Four Corners Power Plant Units?

Based on all of the reasons discussed above, Sithe's approach to determining the short term SO_2 emission rates from San Juan Units 1 and 2 and from all five units of the Four Corners Power Plant is flawed because it is inconsistent with PSD regulations and policy and because it was not consistent with the 1981 New Mexico SO_2 attainment demonstration for San Juan County, New Mexico. Consequently, more appropriate short term emission rates must be determined for the SO_2 PSD increment analysis.

For Units 1 and 2 of the San Juan Power Plant, two different sets of baseline emissions need to be developed – one for the Colorado and Arizona Class I area analysis for which San Juan had not reduced its SO_2 emissions prior to the applicable minor source baseline date for SO_2, and a second for the New Mexico Class I and II areas and the Utah Class I areas for which San Juan Units 1 and 2 had reduced its SO_2 emissions after the applicable SO_2 minor source baseline date.

For the first set of baseline emissions (for Colorado and Arizona Class I areas) at San Juan Units 1 and 2, the allowable SO_2 emission rates that applied at the time of the applicable minor source baseline dates (October 1977 for Colorado and Arizona) must be considered to reflect baseline emissions. As discussed in Section II.A.1. above, the federally enforceable construction permit for San Juan Unit 1 indicated that the SO_2 controls would achieve 79% control (see Enclosure 3), and the EPA-approved SIP specified an SO_2 emission rate for San Juan Unit 1 of 0.34 lb/MMBtu and 65% SO_2 control of SO_2 from what would be produced from combustion of the coal for San Juan Unit 2. See Enclosure 11. For San Juan Unit 1, the 0.34 lb/MMBtu limit from the SIP as in effect in October 1977 reflects 79% control from uncontrolled SO_2 emissions, i.e.,

prior to any coal combustion in the boiler.[46] For San Juan Unit 2, the emission limit corresponding to 65% control from that which would be produced from the combustion of the coal in the boiler must be determined using AP-42 emission factors to estimate the SO_2 emissions exiting the boiler.[47] Thus, 65% control would reflect an emissions rate of 0.50 lb/MMBtu.[48] As discussed above, the EPA-approved 1974 regulation does not specify the averaging time, but the compliance provisions appear to indicate that these would be considered short term average emission limits – at worst, daily limits.[49]

Based on a comparison of the allowable emissions in effect at the time of the applicable SO_2 minor source baseline dates in Colorado and Arizona to what was subsequently approved and modeled to demonstrate attainment of the primary and secondary SO_2 NAAQS in 1981 (i.e., the New Mexico regulation that was approved by EPA on August 27, 1981, 46 Fed.Reg. 43152), what was ultimately deemed necessary by New Mexico in 1981 to provide for attainment of the SO_2 NAAQS at San Juan Unit 1 (i.e., 0.65 lb/MMBtu) was actually less stringent than the allowable emission limit that applied at the time of the Colorado and Arizona SO_2 minor source baseline dates. For San Juan Unit 2, 72% control from the SO_2 exiting the boiler, which is equivalent to an emission rate of 0.40 lb/MMBtu[50] was ultimately required by New Mexico to demonstrate attainment of the SO_2 NAAQS in 1981. As discussed in Section II.A.4.*a.* above, these emission rates were modeled to demonstrate compliance with the 3-hour and 24-hour SO_2 NAAQS, thus these should be considered as the emission rates deemed necessary to attain the short term average SO_2 NAAQS irrespective of the 30-day averaging time provided in the SIP-approved regulation.

Since increment expansion cannot be obtained from emission reductions that were necessary to attain the NAAQS, the lowest emission rate of what was allowed at San Juan Units 1 and 2 at the time of the applicable minor source baseline dates in Colorado and Arizona and what was approved and modeled in 1981 to attain the SO_2 NAAQS must be considered as reflecting baseline emissions from these units. That means an SO_2 emission rate of 0.34 lb/MMBtu for San Juan Unit 1 and an SO_2 emission rate of 0.40 lb/MMBtu for San Juan Unit 2 should be considered to reflect baseline emissions for the Arizona and Colorado SO_2 increment analyses.

To determine SO_2 increment consumption in the Utah Class I analysis and the New Mexico Class I and II SO_2 increment analyses, the actual emissions at the time of the applicable minor source baseline date must be considered in determining baseline emissions from these units since these San Juan Units 1 and 2 had actually reduced emissions as of the applicable minor source baseline dates for these areas. As discussed in Section II.A.2 above, there is evidence to indicate that the SO_2 controls at these units

[46] Uncontrolled SO2 emissions in the coal calculated to be approximately 1.63 lb/MMBtu based on data provided in the San Juan Unit 1 1973 Construction Permit Application, see Enclosure 3.
[47] See footnote 18 for a discussion of the uncontrolled SO2 emissions exiting the boiler, as calculated using AP-42 emission factors.
[48] Sixty-five percent control of an SO2 emission rate exiting the boiler of 1.4286 lb/MMBtu equals 0.5 lb/MMBtu.
[49] See Enclosure 11, New Mexico Regulation 602, Sections D., E., and F.1- 4.
[50] See footnote 43.

were being operated to reduce SO_2 emissions by 90% which would reflect an emission rate lower than the allowable emissions of these units and lower than what was ultimately modeled to demonstrate attainment of the SO_2 NAAQS in 1981. See also Table 4 above. EPA and Sithe should investigate this issue further to determine actual SO_2 emission rates from these units in 1978 (for the New Mexico Class II analysis), 1979 (for the Utah Class I analysis), and 1981 (for the New Mexico Class I analysis).

For the Four Corners Power Plant, it does not appear that these units either had allowable emissions or actual emissions less than what was modeled by New Mexico to demonstrate attainment of the primary and secondary SO_2 NAAQS in 1981. See Sections II.A.3. and 4. above. However, as discussed in Section II.A.4.*d.* above, EPA must provide an attainment demonstration to verify that its proposed FIP (71 Fed.Reg. 53636, September 12, 2006) will ensure attainment of the 3-hour and 24-hour SO_2 NAAQS. This is especially important because EPA has eliminated the plantwide 30-day average SO_2 limit of 72% control that previously applied under the New Mexico regulations and that was previously modeled by New Mexico to demonstrate attainment of the primary and secondary NAAQS. EPA has instead proposed a more stringent SO_2 emission reduction requirement of 88% but which applies on a longer averaging time (i.e., a yearly basis). Further, it's possible that the sulfur content of the coal has changed since what was modeled in 1981. So it is not clear what emission rate is reflective of 88% control and whether that would be deemed sufficient to provide for compliance with the short term average SO_2 NAAQS based on the modeling techniques available today. In addition, as discussed in Section II.A.4.*a.* above, New Mexico did not demonstrate that the 3-hour average plantwide SO_2 limit of 17,900 lb/hr (which EPA has included in its proposed FIP) would ensure attainment of the 3-hour SO_2 NAAQS. And, internal EPA documents indicated that the 1981 modeling could not be relied upon for complex terrain where peak concentrations would most likely occur. Thus, until EPA provides a modeling demonstration for its proposed FIP that indicates the SO_2 emission rates at Four Corners Power Plant that are necessary to provide for attainment of the 3-hour and 24-hour SO_2 NAAQS, it is impossible to know what short term SO_2 emission rates should be considered as the baseline emissions from each of the Four Corners Power Plant units. Consequently, Sithe should not be relying on SO_2 emissions changes at Four Corners Power Plant as expanding the available SO_2 increment. These issues need to be fully researched and determined before Sithe can complete the DREF SO_2 increment analyses.

6. EPA/Sithe Failed to Evaluate Whether Any PSD Compliance Issues Exist that Would Further Limit or Disallow Increment Expanding Emissions at the San Juan and Four Corners Power Plants

Sithe and EPA essentially assumed that, as long as SO_2 emissions were reduced below the level determined necessary to attain the SO_2 NAAQS in the area, then SO_2 emissions reductions at San Juan and Four Corners Power Plants could be creditable as increment expanding in the DREF PSD permitting action. In addition to all of the flaws discussed above with this approach, EPA also failed to determine if there were any PSD compliance issues that could limit increment expansion at any of these power plants.

If an existing emissions unit undertakes a modification that is, or should have been, subject to PSD permitting, then the emission increases associated with that modification *consume* the increment. As has become clear in the numerous enforcement actions regarding modifications at coal-fired power plants brought by EPA over the past ten years, the fact that a facility did not apply for a PSD permit does not mean that modifications that should have been subject to PSD permitting did not occur. Yet, no information was provided in the DREF permit documents or in EPA's AAQIR to indicate that EPA had undertaken a compliance review of Units 1 and 2 of the San Juan Power Plant or of all five of the Four Corners Power Plant emission units to determine whether any such modifications have occurred. Considering that EPA is about to allow the construction of a new power plant that apparently could not be issued a permit without obtaining increment-expanding emissions from these existing power plants, it is imperative that EPA ensure a clean compliance history for each unit and determine that all emission reductions beyond those necessary to attain and maintain the NAAQS can be credited.

7. No Justification Was Provided for Sithe's Assumption that the Cameo Power Plant Expanded the SO_2 Increment

In its Class I SO_2 increment analysis, Sithe also considered SO_2 emission reductions at the Cameo Power Plant in Colorado as increment-expanding emissions. See January 2006 DREF Class I Area Update at 4-23. However, Sithe did not explain whatsoever its basis for determining that SO_2 emissions decreases at this facility occurred after the applicable SO_2 minor source baseline date and why such reductions were creditable as expanding the PSD increment. Without such an explanation, Sithe should not be allowed consider emissions changes at this facility as increment expanding in the DREF SO_2 increment analysis.

B. Sithe Improperly Determined Current Levels of Increment-Affecting Emissions

To determine the current levels of emissions from all of the coal-fired power plant units included in the DREF Class I SO_2 increment analysis, Sithe determined the 99th percentile hourly SO_2 emission rate that actually was emitted from each power plant unit in the year 2003 and in 2004, and then averaged those two 99th percentile values together to arrive a an hourly emission rate for each coal-fired power plant unit. See January 2006 DREF Class I Area Update at 4-22. Sithe then used its calculated "peak" hourly SO_2 emission rate for each coal-fired power plant unit as representing current maximum emissions for both the 3-hour and 24-hour SO_2 increment analyses. This was done for all increment consuming sources, as well as to determine the current level of emissions at the sources Sithe determined to be increment-expanding including San Juan Units 1 and 2 and the Four Corners Power Plant. However, there is no justification for this approach in any federal regulation or guidance.

The New Source Review Workshop Manual specifically addresses how current actual emissions are to be evaluated for increment-affecting sources, and Sithe's approach

contradicts those requirements. Specifically, the New Source Review Workshop Manual provides as follows:

> For a PSD increment analysis, an estimate of the amount of increment consumed by existing point sources generally is based on increases in actual emissions occurring since the minor source baseline date. . . *For any increment-consuming (or increment-expanding) emissions unit*, the actual **emission limit, operating level**, and operating **factor** may all be determined from source records and other information (e.g., State emissions files). For the annual averaging period, the change in the actual ***emissions rate*** should be calculated as the difference between:
>
> - *the current average actual **emissions rate*** ,and
> - *the average actual emissions rate as of the minor source baseline date (or major source baseline date for major stationary sources).*
>
> In each case, the average rate is calculated as the average over previous 2-year period (unless the permitting agency determines that a different time period is more representative of normal source operation).
>
> For each short-term averaging period (24 hours and less), the change in the actual ***emissions rate*** for the particular averaging period is calculated as the difference between:
>
> - *the current maximum actual **emissions rate,** and*
> - *the maximum actual **emissions rate** as of the minor source baseline date (or major source baseline date for applicable major stationary sources undergoing construction before the minor source baseline date).*
>
> **In each case, the maximum rate is the highest occurrence for that averaging period during the previous 2 years of operation.**

EPA's New Source Review Workshop Manual (October 1990 Draft) at C.48-49 [Bold print emphasis Added.]

Clearly Sithe's approach to determining current increment-affecting emissions did not comport with EPA policy.

Sithe's justification for its approach to use 99th percentile hourly emissions is as follows:

- This procedure sets aside the top 1%of hourly emissions as likely to be not representative of normal operation.
- The hourly emissions are conservatively high with respect to expected 3-hour and 24-hour averages.
- The emissions are also conservatively high for multiple-unit facilities in which all units are not operating at peak load simultaneously.

January 2006 DREF Class I Area Update at 4-22.

Sithe opined on this issue further, as follows:

> 1.What is the appropriate emission rate that reflects "maximum actual "emissions, especially if facility-wide emissions could reflect periods with some units lower than peak production or even off-line?
> Discussion: EPA Region 9 talked to other EPA regions on this question. There seems to be agreement that one should use the maximum actual hourly rate, though some regions felt there was some justification for using, e.g., 90th percentile as indicative of "normal" source operation, as opposed to the 100th percentile, which would include anomalous spikes, as it does for at least some of the Four Corners Power Plant (FCPP) units. In Region 8's own modeling for North Dakota SO_2 increment, 90th percentile was used because it is very unlikely that all sources would simultaneously operate at their maximum; and further, the sum of the 90th percentiles was close to the maximum emissions that actually occurred. In this case, the sources are not as clustered as they are for the North Dakota situation ,so a percentile value closer to 100%would be conservative. Due to the fact that the 100th percentile case does include hours that involve upset conditions, and because the shortest regulatory averaging time is 3 hours for SO_2, a 99th percentile selection based upon hourly values for emitting unit should be quite conservative. For more conservatism, the 99th percentile is taken only from the nonzero emission hours for each EGU unit for years 2003 and 2004, and averaged to provide the emission value for input to the model.

Desert Rock Energy Facility Application for Prevention of Significant Deterioration Permit - Class I Area Modeling Update, January 2006, at A-1.

Sithe's and EPA's approach is clearly inconsistent with the longstanding policy outlined in the New Source Review Workshop Manual. It must also be noted that EPA Region VIII's modeling for North Dakota which Sithe referred to was only draft and was never finalized.

Further, it must be realized that there is a purpose to modeling maximum actual short term emission rates in the cumulative increment analysis for a new PSD source. This modeling is supposed to not only ensure that Desert Rock would not cause or contribute to a violation of the PSD increment based on what was being emitted by existing sources in 2003-2004, it is also to ensure protection of the PSD increments beginning when the DREF facility begins operating and for the next 30 years (or more) over the life of the Desert Rock power plant

It must also be noted that one exceedance of the short term average PSD increments is allowed per year. Section 163(a) of the Clean Air Act; 40 C.F.R. §52.21(c). That allowance was likely to account for the possibility of anomalous spikes in emissions, such as those due to malfunctions. However, the fact that malfunctions are typically unexpected, infrequent events does not mean the

anomalous spikes in emissions associated with these types of events don't consume the PSD increment. In fact, EPA policy indicates that excess emissions, even those due to malfunctions, consume the available PSD increment. See, e.g., EPA's September 20, 1999 memorandum entitled "State Implementation Plans: Policy Regarding Excess Emissions During Startup, Shutdown, and Malfunctions" which discusses when affirmative defense provisions can be allowed for excess emissions due to malfunctions "except where a single source or a small group of sources has the potential to cause an exceedance of the. . .PSD increment."[51]

Thus, for all of the above reasons, Sithe should have modeled the 2003-2004 maximum 3-hour average and 24-hour average SO_2 emission rates for each power plant unit in its cumulative SO_2 increment assessment.

A review of the maximum 3-hour and 24-hour average SO_2 emission rates actually emitted by the modeled coal-fired power plants in 2003 and 2004[52] shows that, in almost all cases, these units emitted SO_2 at emission rates higher than what Sithe included for these units in its SO_2 increment assessment for DREF. Tables 9 and 10 show a comparison of the 99th percentile peak hourly emission rate considered as reflecting current emissions in the DREF Class I SO_2 increment analysis as compared to what actually occurred at these units over the 2003-2004 timeframe during the maximum 3-hour and 24-hour average emitting periods.

[51] See Attachment to EPA's September 20, 1999 memorandum entitled "State Implementation Plans: Policy Regarding Excess Emissions During Startup, Shutdown, and Malfunctions" at 3 (included as Enclosure 9 to this report).
[52] Hourly emissions data obtained from EPA's Clean Air Markets Database (CAMD), available at http://www.epa.gov/airmarkets/emissions/raw/index.html.

Table 9: Comparison of 99th Percentile Hourly SO_2 Emission Rate to Maximum 3-Hour Average SO_2 Emission Rate, 2003-2004

Power Plant Unit	99th Percentile Hourly SO_2 Emission Rate, lb/hr[53]	Actual Maximum 3-Hour Average Emission Rate, lb/hr	Number of 3-hour Average Emission Rates > 99th Percentile Hourly SO_2 Emission Rate
Cholla Unit 2	707	2208	64
Hunter Unit 2	741	4816	119
Hunter Unit 3	736	4646	102
San Juan Unit 3	2097	5549	44
San Juan Unit 4	2375	5669	125
Escalante	374	1399	2
Nixon Unit 1	1749	1922	86
Nucla	551	1116	41
San Juan Unit 1	1257	3099	39
San Juan Unit 2	1200	3417	51
Four Corners Unit 1	1275	6012	51
Four Corners Unit 2	1098	5588	57
Four Corners Unit 3	1972	6375	62
Four Corners Unit 4	3721	18382	122
Four Corners Unit 5	3891	13711	147

[53] Sithe data from Spreadsheet entitled "CALPUFF Modeling Background SO_2 Inventory by ENSR.xls." Enclosure 6.

Table 10: Comparison of 99th Percentile Hourly SO_2 Emission Rate to Maximum 24-Hour Average SO_2 Emission Rate, 2003-2004

Power Plant Unit	99th Percentile Hourly SO_2 Emission Rate, lb/hr[54]	Actual CAMD Maximum 24-Hour Average Emission Rate, lb/hr	Number of 24-hour Average Emission Rates > 99th Percentile Hourly SO_2 Emission Rate
Cholla Unit 2	707	817	2
Hunter Unit 2	741	2490	21
Hunter Unit 3	736	1211	7
San Juan Unit 3	2097	2651	2
San Juan Unit 4	2375	3015	12
Escalante	374	460	0
Nixon Unit 1	1749	1826	9
Nucla	551	546	0
San Juan Unit 1	1257	1248	0
San Juan Unit 2	1200	1381	2
Four Corners Unit 1	1275	1661	4
Four Corners Unit 2	1098	1894	5
Four Corners Unit 3	1972	2429	4
Four Corners Unit 4	3721	6704	11
Four Corners Unit 5	3891	5283	16

As these tables show, Sithe greatly underestimated increment consumption (and overestimated increment expansion) by its use of the 99th percentile hourly SO_2 rate, rather than evaluating the maximum 3-hour and 24-hour SO_2 emission rate that occurred at each unit during 2003-2004 as required by EPA policy. This is readily apparent for the 3-hour average SO_2 increment, where there were several 3-hour periods of actual emissions at each emission unit above what Sithe modeled in the DREF cumulative SO_2 Class I increment analysis, but it is also an issue for the 24-hour average SO_2 increment analysis for several units.

Tallying up what Sithe modeled for the increment-consuming units (i.e., those units listed above the darkened line in the tables) shows the extent to which Sithe underestimated increment-consuming emissions in the 3-hour average SO_2 increment analysis. Specifically, the sum of the 99th percentile hourly emission rates for those units above the dark line in the tables is 9,330 lb/hr, compared to the 27,325 lb/hr sum of the maximum actual 3-hour average SO_2 emission rates from these units. Even for the 24-hour increment inventory, the total of what Sithe modeled for these units is only 73% of the total actual maximum 24-hour average SO_2 emission rates from these units which total 13,016 lb/hr.

[54] Sithe data from Table 4-11 of January 2006 DREF Class I Modeling Update, at 4-23, converted from grams per second to pound per hour.

Further, a comparison of Sithe's assumed current emission rates for San Juan Units 1 and 2 and the Four Corners Power plant, which Sithe considered to be increment expanding in its increment analyses, to the actual maximum 3-hour and 24-hour average emission rates at these units shows that Sithe's analysis improperly assumed much greater reductions at these emission units than actually occurred in 2003 and 2004. In fact, a review of the total plantwide 3-hour average emissions for the San Juan Power Plant that actually occurred at this power plant during 2003-2004 (from EPA's CAMD data) indicates that the San Juan Power Plant SO2 emissions as reported to CAMD exceeded its allowable 3-hour SO_2 plantwide cap of 13,000 lb/hr once each in 2003 and 2004.[55] Similarly, a review of the total plantwide 3-hour average emissions for the Four Corners Power Plant that actually occurred at this facility during 2003-2004 (from EPA's CAMD data) shows that the plant's SO2 emissions as reported to CAMD exceeded the EPA's proposed 3-hour emission limit of 17,900 lb/hr once in 2003 and twice in 2004.[56] If there are compliance issues with these facilities, then it seems questionable whether there should be any increment-expanding emissions modeled from these sources in the SO2 increment analyses, at least for the 3-hour average SO2 increment.

C. Sithe Failed to Determine if There Were Increment Consuming Emissions Changes at All Facilities in the Region

With the exception of the San Juan and Four Corners Power Plants, it appears that Sithe only considered those emission units with emissions that are wholly increment consuming in its Class I SO_2 increment analysis. However, any emissions increase that occurs at a source which existed at the time of the applicable minor source baseline date consumes the available PSD increment. Thus, Sithe should have evaluated the other major sources in the region to determine if SO_2 emissions had changed at these emission units since the applicable minor source baseline date and included the increment-affecting emissions in its cumulative SO_2 increment analysis.

III. With Changes Made Only to the San Juan Power Plant Baseline Emissions Assessment, Sithe's Model Shows that DREF Will Contribute to SO_2 PSD Increment Violations At Mesa Verde National Park

Based on the discussions in Section II.A. above, it is clear that the hourly SO_2 emission rates determined by Sithe to reflect baseline emissions at Units 1 and 2 of the San Juan Power Plant are seriously in error. As discussed in Section II.A.5. above, there is substantial evidence to indicate that the proper SO_2 baseline emissions for San Juan Units 1 and 2 would be lower than the emission rates modeled by New Mexico in 1981 to demonstrate attainment of the SO_2 NAAQS for the 1981 New Mexico SO_2 SIP. If this is the case, then no SO_2 reductions at Units 1 and 2 of the San Juan power plant would be

[55] These exceedances of the 13,000 lb/hr 3-hour average limit occurred on 1/3/03 and 3/30/04.
[56] These exceedances of the EPA's proposed 17,900 lb/hr 3-hour average limit occurred on 8/5/03 and 4/4/04.

considered to be increment expanding, and possibly instead these units may have increment consuming emissions.

Even if it is appropriate to consider the SO_2 emissions rates at San Juan Units 1 and 2 that were modeled by New Mexico in 1981 to demonstrate attain the NAAQS as equal to the baseline emissions of these units, it is clear that Sithe erred in determining the short term average SO_2 emission rates at San Juan Units 1 and 2 deemed necessary to attain the SO_2 NAAQS. Indeed, Sithe's approach to determining the short term average SO_2 emission rates necessary to attain the NAAQS improperly resulted in an inflated level of baseline emissions from San Juan Units 1 and 2, which thus allowed Sithe to model a greater amount of SO_2 emissions as increment expanding. See Table 7 of this report. Sithe also was not justified in assuming that the 99^{th} percentile hourly emissions rate at each of these units, as well as all other existing power plant units modeled, reflected the maximum 3-hour and 24-hour SO_2 emission rates from increment-affecting sources. See Section II.B. above.

To determine the significance of these errors, modeling analyses were completed. It is important to note that initial modeling runs were completed based on review of the information available in the DREF administrative record regarding the level of control at San Juan Units 1 and 2 and the Four Corners Power Plant that was deemed necessary to show attainment of the SO_2 NAAQS. Subsequently, the author received documents from EPA Region VI regarding the New Mexico SO_2 SIP for San Juan County that shed light on many issues regarding the level of SO_2 control that was modeled to show attainment of the SO_2 NAAQS. See Section II.A.4. of this report. The results of the modeling analyses are in the November 8, 2006 report entitled "Cumulative SO_2 Modeling Analyses of Desert Rock Energy Facility and Other Sources at PSD Class I Areas," prepared by Khanh Tran of AMI Environmental, included with this report as Enclosure 8. (Tran report).

All of the modeling analyses were based on the same model and modeling inputs used by Sithe in its cumulative Class I SO_2 increment analysis with two exceptions: 1) All of the DREF SO_2 emissions sources were included in the modeling analyses, rather than just the DREF boilers that were modeled in Sithe's cumulative Class I SO_2 increment analysis (see Tran report at page 3); and 2) The increment affecting emissions of the San Juan power plant were revised in various scenarios.

First, two modeling analyses using 2001 MM5 meteorological data were conducted. Those scenarios modeled are as follows:

> 1) Assuming there are no increment affecting emissions (meaning zero increment expanding emissions) from Units 1 and 2 of the San Juan Power Plant. This analysis would reflect the likelihood that Units 1 and 2 of the San Juan power plant were either emitting SO_2 at lower emission rates, or had lower allowable emission rates, at the time of the applicable minor source baseline date than what was considered necessary to attain the SO_2 NAAQS and that current emission rates are higher. If this was the case,

then the increase in emissions at San Juan Units 1 and 2 would be increment-consuming, but for this analysis we assumed that San Juan Units 1 and 2 did not affect the PSD increment at all; and

2) Assuming that San Juan Units 1 and 2 were emitting SO_2 exactly at the level of emissions allowed under the 3-hour average plantwide SO_2 cap of 13,000 lb/hr at the time of the applicable baseline date. This scenario would reflect the San Juan Power Plant emitting at the maximum 3-hour average SO_2 emission rate allowed under the 1981 SO_2 SIP as baseline emissions, although as discussed above, it does not appear that this was the level of control deemed necessary to attain the SO_2 NAAQS and, in fact, it is not clear whether attainment of the NAAQS can be demonstrated for this plantwide emission limit when the Four Corners Plant is also operating at its 3-hour plantwide cap of 17,900 lb/hr. See Section II.A.4. above. In this analysis, an emission rate of 0.765 lb/MMBtu was determined to reflect the 3-hour average plantwide 13,000 lb/hr SO_2 limit (by dividing 13,000 lb/hr by the sum of the heat input capacities of the four San Juan units), and then baseline emissions for San Juan Units 1 and 2 were determined by multiplying each unit's heat input capacity (as reported in a 2/25/75 letter from PNM to New Mexico (Enclosure 4)) by 0.765 lb/MMBtu. This level of "baseline emissions" was then subtracted from Sithe's determination of the 99th percentile 2003-2004 average hourly emission rate from San Juan Units 1 and 2[57] to arrive at the following SO_2 emission rates modeled as increment expanding:
-1,223.8 lb/hr from Unit 1, and -1,214.8 lb/hr for Unit 2. See Tran Report at 3.

The maximum (high second high) SO_2 concentrations predicted by modeling these two scenarios are provided in Table 11 below, which is excerpted from the Tran report at 4. In either case, the DREF would be considered to contribute to violations of the 3-hour average and 24-hour average SO_2 PSD increments at Mesa Verde National Park.

[57] See the worksheet entitled "SO2 expansion" in the spreadsheet entitled "CALPUFF Modeling Background SO2 Inventory by ENSR.xls." (Enclosure 6).

Table 11: Maximum Cumulative SO_2 Concentrations (ug/m^3) predicted by Calpuff at Mesa Verde NP under Two Emissions Scenarios for San Juan Units 1 & 2 (2001 Meteorological Data)

Averaging Period	Scenario #1 (No Emissions from San Juan Units 1&2)	Scenario #2 Emissions -307.31 g/s from SJ Units 1 &2)	PSD Class I Increments (ug/m^3)
3-hour	49.732	34.669	25
24-hour	8.8556	5.9181	5
Annual	0.50944	0.38195	2

The scenarios modeled represent the upper bound and lower bound of the amount of increment expanding SO_2 emissions that could potentially be considered at San Juan Units 1 and 2 in the DREF cumulative SO_2 increment analyses. However, it is important to note that these scenarios do not even take into account Sithe's flawed approach of determining current maximum short term average SO_2 emission rates from San Juan Units 1 and 2 (as well as all other sources included in the modeling), which is discussed in Section II.B. above. These analyses also do not take into account the likelihood that there are increment consuming emissions from San Juan Units 1 and 2, especially for the 3-hour average SO_2 increment, when the maximum 3-hour average emissions from 2003-2004 at each unit are considered to reflect current 3-hour average emission rates as required by the New Source Review Workshop Manual. Further, no changes were made to what Sithe modeled as increment-expanding from the Four Corners Power Plant even though, as discussed above, it seems likely that Sithe overestimated the short term emissions rates at the Four Corners Power Plant units that were deemed necessary to attain the SO_2 NAAQS and underestimated current emissions by using 99^{th} percentile.

Based on the results of modeling these scenarios which showed SO_2 increment violations at Mesa Verde National Park, a third modeling analysis was done using 2002 meteorological data as follows:

> For modeling Scenario #3, it was again assumed that the San Juan Power Plant emitted at its 3-hour average 13,000 lb/hr emissions cap that applies under the 1981 New Mexico SIP (allocated among the four units as discussed above). Further, it was also assumed that these units currently emit at 13,000 lb/hr on a plantwide basis (again, allocated among the four units as discussed above) as maximum short term emission rates. This scenario was modeled for several reasons: 1) to assume a maximum short term average SO_2 baseline emission rate for each unit that reflects the maximum that would be allowed under the 1981 New Mexico SIP, and 2) to reflect the maximum short term average that the San Juan Power Plant can emit at currently under the enforceable SIP. Indeed, as discussed in Section II.B. above, it appears that the San Juan Plant exceeded this 13,000 lb/hr cap once in 2003 and 2004, so this scenario is

not unlikely at least for the 3-hour average time period. This approach meant that San Juan Units 1 and 2 were again not considered to expand or consume increment, and San Juan Units 3 and 4 were considered to consume increment based on these unit's allocation of the 13,000 lb/hr plantwide cap (i.e., each unit emitting SO_2 at 4,053 lb/hr). For San Juan Units 3 and 4, this level of emissions is higher than the 99th percentile values modeled by Sithe (i.e., 2,097 lb/hr and 2,375 lb/hr), is lower than the maximum 3-hour average emission rates that actually occurred at each of these units over 2003 and 2004 (5,549 lb/hr and 5,869 lb/hr), and is higher than the maximum 24-hour average emission rates that actually occurred at these units (2,651 lb/hr and 3,015 lb/hr respectively). See Tables 9 and 10 above. All other source emissions were left as originally modeled by Sithe, including the Four Corners Power Plant.

The maximum (high second high) SO_2 concentrations predicted by modeling this scenario #3 is provided in Table 12 below, which is excerpted from the Tran report at 4, also indicated that DREF would contribute to violations of the 3-hour and 24-hour average SO_2 increments at Mesa Verde National Park. Further, DREF contribution to these concentrations was greater than the EPA's proposed Class I SO_2 significance levels.[58]

Table 12: Maximum Cumulative SO_2 Concentrations (ug/m^3) and DREF Contributions at Mesa Verde NP under Emissions Scenario #3 (Zero Emissions for San Juan 1&2; 1021.356 g/s for San Juan 3&4) (2002 Meteorological Data)

Averaging Period	Total Increment from DREF and cumulative sources	Contribution from DREF alone	PSD Class I Increments (ug/m^3)
3-hour	65.593	1.2192	25
24-hour	12.060	0.4530	5

Subsequent to receipt of the historical New Mexico SO_2 SIP files from EPA Region VI, a fourth emissions scenario was modeled with 2002 meteorological data, as follows:

Scenario #4 was to reflect as baseline emissions the SO_2 emissions levels that were modeled and approved by EPA in 1981 to show attainment of the 3-hour and 24-hour average SO_2 NAAQS, i.e., 0.65 lb/MMBtu at San Juan Unit 1 and 72% control or 0.4 lb/MMBtu at San Juan Unit 2. See Section II.A.4. above. For Scenario #4a, current maximum 3-hour

[58] EPA proposed Class I area significant impact levels in July of 1996 (61 Fed.Reg. 38338, July 23, 1996). However, EPA never finalized promulgation of those significant impact levels. Until significant impact levels for Class I increment analyses are promulgated by EPA, *any* impact in a Class I area by DREF should be considered significant. But for this scenario and scenario #4, we determined whether DREF's contribution would be greater than the EPA's proposed SO2 significant impact levels for Class I areas.

emission rates were determined for each unit (shown in Table 9). However, because the sum of these individual maximum 3-hour average emission rates exceeded the plantwide 3-hour average SO_2 SIP limit of 13,000 lb/hr, it was assumed that the 13,000 lb/hr cap allocated across all four units based on their share of total heat input capacity reflected the maximum 3-hour average emission rates that could occur at each unit. Then the difference between the allocated 13,000 lb/hr cap and what was modeled to show attainment of the SO_2 NAAQS in 1981 was modeled:

San Juan Unit 1: 374 lb/hr
San Juan Unit 2: 1,153 lb/hr
San Juan Unit 3: 4,053 lb/hr
San Juan Unit 4: 4,053 lb/hr

For Scenario #4b, current maximum 24-hour emission rates were determined for each unit (shown in Table 10). Because the total of these emission rates was less than the 13,000 lb/hr cap, the maximum 24-hour average emission rates over 2003-2004 were assumed to reflect current emissions consistent with the New Source Review Workshop Manual as discussed above. Then the difference between the maximum 24-hour average emission rate at each unit and what was modeled to show attainment of the SO_2 NAAQS in 1981 was modeled:

San Juan Unit 1: -858 lb/hr
San Juan Unit 2: 119 lb/hr
San Juan Unit 3: 2,651 lb/hr
San Juan Unit 4: 3,015 lb/hr

San Juan Unit 1 was considered to expand the 24-hour average increment in this model run.

The maximum (high second high) SO_2 concentrations predicted by modeling these scenarios are provided in Tables 13 and 14 below, which is excerpted from the Tran report at 5. These model runs also indicate that DREF would contribute to violations of the 3-hour and 24-hour average SO_2 increments at Mesa Verde National Park. Further, DREF contribution to these concentrations was greater than the EPA's proposed Class I SO_2 significance levels.

Table 13: Maximum Cumulative SO_2 Concentrations (ug/m^3) and DREF Contributions at Mesa Verde NP under Emissions Scenario #4a (192.402 g/s for San Juan 1&2; 1021.356 g/s for San Juan 3&4; zero emissions for Four Corners Units) (2002 Meteorological Data)

Averaging Period	Total Increment from DREF and cumulative sources	Contribution from DREF alone	PSD Class I Increments (ug/m^3)
3-hour	86.978	1.2533	25

Table 14: Maximum Cumulative SO_2 Concentrations (ug/m^3) and DREF Contributions at Mesa Verde NP under Emissions Scenario #4b (-93.114 g/s for San Juan 1&2; 713.916 g/s for San Juan 3&4; zero emissions for Four Corners Units) (2002 Meteorological Data)

Averaging Period	Total Increment from DREF and cumulative sources	Contribution from DREF alone	PSD Class I Increments (ug/m^3)
24-hour	8.5284	0.43058	5

All of the above modeling scenarios provide ample evidence that, had Sithe modeled more appropriate emission rates at just the San Juan Power Plant in its SO_2 Class I increment analysis, Sithe would have determined that DREF would contribute to 3-hour and 24-hour increment violations at Mesa Verde National Park. Yet, none of these modeling scenarios alter what was modeled by Sithe as increment-expanding at Four Corners Power Plant or what was modeled as reflecting current emissions at all of the other power plants modeled (i.e., 99^{th} percentile vs maximum 3-hour and 24-hour average emission rates).

No modeling scenario was done for the Four Corners Power Plant because it is difficult to know for certain what emissions rate reflects the level of control necessary to demonstrate attainment of the 3-hour and 24-hour average SO_2 NAAQS. This is especially because EPA has proposed a FIP that does not include the emission control requirement of 72% control that applied plantwide on a 30-day average basis under the 1981 New Mexico SIP and that was modeled to show attainment of the SO_2 NAAQS in 1981, and instead EPA has proposed a more stringent SO_2 reduction requirement but it applies on a longer yearly averaging time. EPA also did not provide any indication in its proposed FIP rulemaking of what emissions rate would reflect this higher level of SO_2 control. Since sulfur content of the coal could have changed since 1981, it is difficult to determine the emission rate that the proposed 88% control requirement reflects. Further, EPA should have done a modeling demonstration as a necessary component to proposed a FIP for the Four Corners Power Plant. This is especially necessary given all of the concerns that EPA expressed with the 1981 modeling, as discussed above.

However, while no revised modeling of the Four Corners Power Plant was done, it is interesting to determine what the increment-affecting emissions would be had Sithe considered the 72% control (0.47 lb/MMBtu) emissions level that was modeled by New Mexico to demonstrate attainment of the SO_2 NAAQS in 1981 as reflecting 3-hour and 24-hour average baseline emissions, and had Sithe considered as current emissions the maximum 3-hour and 24-hour average emission rates that occurred at each Four Corners unit during 2003-2004 as bounded by the 3-hour average plantwide cap of 17,900 lb/hr that would apply under the EPA's proposed FIP. Tables 15 and 16 below shows that the difference in increment-affecting emissions between this more appropriate approach to determining increment consumption as compared to Sithe's approach used in the DREF permit is quite significant. Indeed, it appears that the Four Corners Power Plant would be

considered to consume both the 3-hour and 24-hour average SO_2 increment rather than expand it.

Table 15: 3-Hour Average Increment-Affecting SO_2 Emissions at the Four Corners Power Plant based on Current Maximum Emission Rates and a Baseline Emissions Rate of 72% Control

Four Corners Unit	Baseline Emissions at 72% Control (0.47 lb/MMBtu)[59]	Maximum 3-Hour Average Emissions, lb/hr[60]	Increment Affecting Emissions (Max 3-hour minus 72% control), lb/hr	Increment Affecting Emissions Modeled by Sithe, lb/hr
1	804	1,568	765	-631.96
2	804	1,568	765	-535.85
3	954	1,862	908	-509.46
4	3,306	6,451	3,145	-1333.3
5	3,306	6,451	3,145	-872.2

Table 16: 24-Hour Average Increment-Affecting SO_2 Emissions at the Four Corners Power Plant based on Current Maximum Emission Rates and a Baseline Emissions Rate of 72% Control

Four Corners Unit	Baseline Emissions at 72% Control (0.47 lb/MMBtu)	Maximum 24-Hour Average Emissions, lb/hr[61]	Increment Affecting Emissions (Max 24-hour minus 72% control), lb/hr	Increment Affecting Emissions Modeled by Sithe, lb/hr
1	804	1,661	857	-631.96
2	804	1,894	1,091	-535.85
3	954	2,429	1,475	-509.46
4	3,306	4,004	698	-1333.3
5	3,306	5,022	1,716	-872.2

[59] These emission rates were calculated by multiplying the maximum heat input capacities of each unit the emissions rate of 0.47 lb/MMBtu (which EPA indicated was reflective of 72% control in its 1981 approval of the New Mexico SO2 SIP).
[60] A review of 2003-2004 maximum 3-hour average SO2 emissions at each Four Corners Unit was conducted (as shown in Tables 9 and 10 above) and the sum totaled more than the 17,900 lb/hr 3-hour average plantwide cap of the EPA proposed FIP would allow. Consequently, the 17,900 lb/hr cap was allocated to each unit based on heat input capacity and was assumed to reflect current maximum 3-hour average emission rates at each unit.
[61] Maximum 24-hour average emissions over 2003-2004 as shown in Table 10 above.

Thus, with all deficiencies in the SO_2 increment affecting modeling addressed, the predicted SO_2 increment violations would likely be of greater magnitude and more widespread than what was modeled for the various scenarios for the San Juan Power Plant.

IV. CONCLUSION

Due to all of the deficiencies in the DREF cumulative Class I SO_2 increment analysis described above, Sithe's analysis cannot be relied upon by EPA to ensure that DREF won't cause or contribute to a violation of the 3-hour average or 24-hour average SO_2 increments in affected Class I areas. Just remedying some of the deficiencies in what was modeled for the San Juan Power Plant shows that there will be violations of the 3-hour and 24-hour average SO_2 increments in Mesa Verde National Park and DREF's contribution to those violations would exceed the EPA's proposed Class I significance levels.[62] If all of the various deficiencies described above are accounted for in a new modeling exercise, the violations of the 3-hour and 24-hour average SO_2 increments will likely be of greater magnitude in Mesa Verde National Park and potentially may also be found in other Class I areas in the region. Further, many of the deficiencies in the Class I increment inventory likely also apply to Sithe's cumulative Class II SO_2 increment analysis. Based on the available documentation regarding the 1981 New Mexico SO_2 SIP and considering the Four Corners Power Plant FIP that EPA has proposed, EPA should conduct further modeling using current modeling techniques to adequately assess the 3-hour and 24-hour average emission rates at the Four Corners Power Plant and also at the San Juan Power Plant that will ensure compliance with the 3-hour and 24-hour average SO_2 NAAQS. Accordingly, EPA cannot issue the permit until it is verified, based on a proper increment –affecting emissions inventory, that DREF won't cause or contribute to a violation of the Class I SO_2 increment. Further, if it is found that SO_2 increment violations are currently existing at Mesa Verde National Park or other Class I areas in the region that will be affected by DREF, EPA policy makes clear that the increment violations must be entirely corrected before the DREF permit can be issued. See 45 Fed.Reg. 52678, August 7, 1980.

[62] See Tran Report , Enclosure 8.

Enclosures

Enclosure 1:	20 NMAC 2.31, as approved into the New Mexico SIP.
Enclosure 2:	October 15, 1973 letter from Public Service Company of New Mexico to the New Mexico Environmental Improvement Agency regarding its "Application for Certification of Registration" of San Juan Unit 2
Enclosure 3:	Application for Authority to Construction San Juan Unit 1, received by the state of New Mexico on May 18, 1973
Enclosure 4:	February 25, 1975 letter from Public Service Company of New Mexico to the New Mexico Environmental Improvement Agency with the Construction Schedule for Unit 1 at San Juan Station, January 1975 attached.
Enclosure 5:	May 9, 1975 Minutes of the Meeting of the Environmental Improvement Board of New Mexico
Enclosure 6:	Spreadsheet entitled "CALPUFF Modeling Background SO_2 Inventory by ENSR.xls"
Enclosure 7:	Draft "Four Corners Timeline for SO_2 Regulation Development"
Enclosure 8:	November 9, 2006 report entitled "Cumulative SO_2 Modeling Analyses of Desert Rock Energy Facility and Other Sources at PSD Class I Areas," prepared by Khanh Tran of AMI Environmental
Enclosure 9 :	EPA's September 20, 1999 memorandum entitled "State Implementation Plans: Policy Regarding Excess Emissions During Startup, Shutdown, and Malfunctions"
Enclosure 10:	Excerpts from the July 14, 1978 transcript of proceedings In The Matter Of: The Variance Request of the Public Service Company of New Mexico for its San Juan Coal-Fired Generating Unit No. 3 For A Variance Through May 1, 1982, before the New Mexico Environmental Improvement Board, Sante Fe, New Mexico.
Enclosure 11:	December 13, 1974 New Mexico Environmental Improvement Board Air Quality Control Regulation Number 602, which was approved by EPA at 41 Fed.Reg. 8057-8 (February 24, 1976) and modified at 41 Fed.Reg. 34749 (August 17, 1976).

Enclosure 12:	June 9, 1978 New Mexico Environmental Improvement Board Air Quality Control Regulation Number 602, which was approved by EPA at 45 Fed.Reg. 24460 (April 10, 1980).
Enclosure 13:	Excerpts from the February 4, 1981 New Mexico Environmental Improvement Board document entitled "Control Strategy Demonstration: New Mexico Air Quality Control Regulation 60, Coal Burning Equipment –Sulfur Dioxide" and from the February 13, 1981 supplement to this document.
Enclosure 14:	The November 24, 1980 New Mexico rule 602.
Enclosure 15:	July 23, 1981 Memorandum from Frances E. Phillips, Acting Regional Administrator, to Anne M. Gorsuch, Administrator of EPA.

This report was prepared by Vicki Stamper, an environmental engineer with more than fifteen years experience working on air quality issues, with a primary focus on the prevention of significant deterioration permitting program. Ms. Stamper currently works as a consultant to non-profit and environmental groups providing expertise and technical assistance on various air quality issues. A copy of Ms. Stamper's Curriculum Vitae is enclosed with this report.

Exhibit C
to September 30, 2008 Affidavit of Victoria R. Stamper

November 9, 2006 Tran Report Entitled
"Cumulative SO2 Modeling Analyses of Desert Rock Energy Facility and Other Sources at PSD Class I Areas"

Cumulative SO2 Modeling Analyses of Desert Rock Energy Facility and Other Sources at PSD Class I Areas

November 9, 2006

Prepared by:

Khanh Tran
Principal
AMI Environmental
206 Black Eagle Ave
Henderson, NV 89015
(702)564-9186
http://www.amiace.com

Table of Contents

Section		Page
I.	Modeling Methodologies	2
II.	Emissions Scenarios and Modeling Results	3
III.	References	6

Appendix A - Output of Calpost for Scenario #1 (Zero Emissions from San Juan 1&2)

Appendix B - Output of Calpost for Scenario #2 (Emissions of 307.31 g/s from San Juan 1&2)

Appendix C - Output of Calpost for Scenario #3 (Zero Emissions from San Juan 1&2; Emissions of 1021.356 g/s from San Juan 3&4)

Appendix D - Output of Calpost for Scenario #4a (Emissions San Juan 1&2=192.402 g/s; San Juan 3&4=1021.356 g/s; Four Corners units=0)

Appendix E - Output of Calpost for Scenario #4b (Emissions San Juan 1&2=-93.114 g/s; San Juan 3&4=713.916 g/s; Four Corners units=0)

AMI Environmental has performed a cumulative modeling analysis of sulfur dioxide (SO_2) emissions emitted by the Desert Rock Energy Facility (DREF) and other cumulative sources. DREF is a 1500-MW coal-fired power plant that has been proposed in the Four Corners area by Sithe Global Power, LLC (Sithe). AMI Environmental (AMI) has been retained by Western Clean Energy Campaign to review and comment on the air quality and visibility impact analyses of the proposed facility. These analyses have been conducted for the Prevention of Significant Deterioration (PSD) Permit Application that has been submitted by Sithe to U.S. Environmental Protection Agency (EPA) Region 9 (see References in Section III below).

I. MODELING METHODOLOGIES

Model Selection

To be consistent with the results of the modeling analysis performed by ENSR Corporation on behalf of Sithe, the same versions of the Calpuff model and its supporting programs (Calmet for meteorological data, Postutil and Calpost for post-processing) of the PSD Application were used by AMI in the current modeling. These model executables along with the input files have been provided to AMI by EPA Region 9 as part of the Electronic Modeling Archive (see References in Section III below).

Meteorological Data

The Calpuff modeling used the meteorological data generated by the Calmet program from the 2001 and 2002 meteorological output of the mesoscale model MM5. These MM5 datasets have been used by ENSR in the PSD modeling. They have a grid resolution of 36 km (2001 data) and 12 km (2002 data). They have been provided to AMI by EPA Region 9 as part of the Electronic Modeling Archive (see References in Section III below). Using the MM5 data, the Calmet generated hourly three-dimensional windfields and other meteorological inputs on a 4-km grid for use by the Calpuff model.

Receptors

The Calpuff modeling predicts SO2 concentrations at discrete receptors located at all 15 PSD Class I areas. These discrete receptors have been selected and recommended by the National Park Service for air quality and visibility modeling. The ENSR modeling used 3364 discrete receptors for 14 Class I areas, except Mesa Verde National Park. We have added 312 discrete receptors for Mesa Verde, for a total of 3676 discrete receptors.

II. EMISSIONS SCENARIOS AND MODELING RESULTS

The PSD modeling used the emissions and stack parameters of DREF and other cumulative sources shown in Table 4-11 (page 4-23) of the January 2006 Class I Area Modeling Update. The modeling performed by AMI used the same emissions and stack parameters except for the following differences:

1. Low-level emissions from DREF have also been modeled,
2. Emission Scenario #1 with zero emissions from San Juan Units 1 &2,
3. Emission Scenario # 2 with a combined emission rate of -307.31 g/s from San Juan 1 & 2,
4. Emissions Scenario #3 with zero emissions from San Juan 1& 2 and a combined emission rate of 1021.356 g/s from San Juan 3&4,
5. Emissions Scenario #4a with a combined emissions rate of 192.402 g/s from San Juan 1& 2, a combined emission rate of 1021.356 g/s from San Juan 3&4 and zero emissions from all Four Corners units, and
6. Emissions Scenario #4b with a combined emissions rate of -93.114 g/s from San Juan 1& 2, a combined emission rate of 713.916 g/s from San Juan 3&4 and zero emissions from all Four Corners units.

The PSD Permit Application modeling only considered the SO_2 emissions from the main boilers. In this modeling performed by AMI, the low-level emissions from the auxiliary boilers and other low-level sources (emergency diesel generators, firewater pumps) have also been modeled. An emission rate of 1.6823 g/s and stack parameters shown in Table 2-3 of the June 2006 Class II Area Modeling Update have been used in the modeling.

Five alternative emission scenarios were modeled for the San Juan generation station. Units 1 and 2 are expanding sources while Units 3 and 4 are consuming sources in the PSD modeling. In the first scenario, these expanding sources are assumed to have no emissions. In the second scenario, a combined emission rate of -307.31 g/s has been used (-154.2 g/s from San Juan Unit 1, and -153.11 g/s from San Juan Unit 2). This combined rate represents a 57% reduction of their original emissions of -722.069 g/s in the PSD modeling. In the third scenario, San Juan Units 1 &2 are assumed to have no emissions, and a combined emission rate of 1021.356 g/s has been used for the increment-consuming Units 3&4 (510.678 g/s from San Juan Unit 3, and 510.678 g/s from San Juan Unit 4).

Emissions Scenario #4a was modeled with a combined emissions rate of 192.402 g/s from San Juan 1& 2, a combined emission rate of 1021.356 g/s from San Juan 3&4 and zero emissions from all Four Corners units. Emissions Scenario #4b was modeled with a combined emissions rate of -93.114 g/s from San Juan 1& 2, a combined emission rate of 713.916 g/s from San Juan 3&4 and zero emissions from all Four Corners units.

Emissions scenarios 1 and 2 were modeled with the 2001 meteorological data. Modeling results are summarized in Table 1 below and outputs of the Calpost postprocessor are provided in Appendices A and B. This table shows that both short-term (3-hour and 24-hour) PSD Class I increments will be exceeded by the maximum concentrations (2nd high) predicted under both emissions scenarios for San Juan Units 1 and 2. Maximum concentrations of Scenario #1 are higher than those obtained under Scenario #2. These maximum concentrations were predicted by the Calpuff model to occur at the Mesa Verde National Park. This PSD Class I area is located about 80 km north of the DREF site. The annual-averaged maximum concentrations are well below the PSD Class I area increment of 2 ug/m^3.

Table 1 – Maximum Cumulative SO2 Concentrations (ug/m^3) predicted by Calpuff at Mesa Verde NP under Two Emissions Scenarios for San Juan Units 1 & 2 (2001 Meteorological Data)

Averaging Period	Scenario #1 (No Emissions from San Juan Units 1&2)	Scenario #2 Emissions=307.31 g/s from SJ Units 1 &2)	PSD Class I Increments (ug/m^3)
3-hour	49.732	34.669	25
24-hour	8.8556	5.9181	5
Annual	0.50944	0.38195	2

Emissions scenario #3 was modeled with the 2002 meteorological data. Modeling results are summarized in Table 2 below and the Calpost ouputs are provided in Appendix C. This table shows that both short-term (3-hour and 24-hour) PSD Class I increments will be largely exceeded by the maximum concentrations (2nd high). The 3-hr increment will be exceeded by 260%, and the 24-hr increment by 240%. The maximum concentrations were predicted by the Calpuff model to occur at the Mesa Verde National Park (Receptor #3372 for 3-hr and Receptor #3376 for 24-hr). Table 2 also shows the contributions from DREF emissions to these maximum concentrations (1.21892 ug/m^3 to the 3-hr concentration and 0.4530 ug/m^3 to the 24-hr concentration). Thus, the DREF contributions are considered to be significant since they exceed the EPA-proposed significance levels (1 ug/m^3 for 3-hr and 0.2 ug/m^3 for 24-hr).

Table 2 – Maximum Cumulative SO2 Concentrations (ug/m^3) and DREF Contributions at Mesa Verde NP under Emissions Scenario #3 (Zero Emissions for San Juan 1&2; 1021.356 g/s for San Juan 3&4) (2002 Meteorological Data)

Averaging Period	Total Increment from DREF and cumulative sources	Contribution from DREF alone	PSD Class I Increments (ug/m^3)
3-hour	65.593	1.2192	25
24-hour	12.060	0.4530	5

Both emissions scenarios #4a and #4b were modeled with the 2002 meteorological data. Modeling results for Emission Scenario #4a are summarized in Table 3 below and the Calpost ouputs are provided in Appendix D. This table shows that the 3-hour PSD Class I increment will be largely exceeded by the cumulative concentration (2nd high) by about 350%. This concentration was predicted by the Calpuff model to occur at the Mesa Verde National Park (Receptor #3371). Table 3 also shows the contribution from DREF emissions to this cumulative concentration (1.2533 ug/m^3). Thus, the DREF contribution is considered to be significant since it exceeds the EPA-proposed significance level (1 ug/m^3 for 3-hr).

Table 3 – Cumulative SO2 Concentration (ug/m^3) Exceeding the PSD Class I Increment with Significant DREF Contribution at Mesa Verde NP under Emissions Scenario #4a (192.402 g/s for San Juan 1&2; 1021.356 g/s for San Juan 3&4; zero emissions for Four Corners Units) (2002 Meteorological Data)

Averaging Period	Total Increment from DREF and cumulative sources	Contribution from DREF alone	PSD Class I Increment (ug/m^3)
3-hour	86.978	1.2533	25

Modeling results for Emission Scenario #4b are summarized in Table 4 below and the Calpost ouputs are provided in Appendix E. This table shows that the 24-hour PSD Class I increment will be exceeded by the cumulative concentration (2nd high) by about 70%. This concentration was predicted by the Calpuff model to occur at the Mesa Verde National Park (Receptor #3371). Table 4 also shows the contribution from DREF emissions to this cumulative concentration (0.43058 ug/m^3). Thus, the DREF contribution is considered to be significant since it exceeds the EPA-proposed significance level (0.2 ug/m^3 for 24-hr).

Table 4 – Cumulative SO2 Concentration (ug/m^3) Exceeding the PSD Class I Increment with Significant DREF Contribution at Mesa Verde NP under Emissions Scenario #4b (-93.114 g/s for San Juan 1&2; 713.916 g/s for San Juan 3&4; zero emissions for Four Corners Units) (2002 Meteorological Data)

Averaging Period	Total Increment from DREF and cumulative sources	Contribution from DREF alone	PSD Class I Increment (ug/m^3)
24-hour	8.5284	0.43058	5

III. REFERENCES

Sithe Global Power/ENSR Documents

Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility. Prepared for Steag Power LLC by ENSR Corporation, ENSR Document No. 09417-360-250R1, May 2004 (hereinafter referred to as *May 2004 PSD Permit Application*).

Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility. Prepared for Steag Power LLC by ENSR Corporation, ENSR Document February 2004 (hereinafter referred to as *February 2004 PSD Permit Application*).

Desert Rock Energy Facility Application for Prevention of Significant Deterioration Permit – Class I Area Modeling Update. Prepared for Sithe Global Power LLC by ENSR Corporation, ENSR Document No. 10784-001-0004, January 2006 (hereinafter referred to as *January 2006 Class I Area Modeling Update*).

Desert Rock Energy Facility: Class I Area Modeling Supplement. Prepared for Sithe Global Power LLC by ENSR Corporation, ENSR Document No. 10784-001-0004, March 2006 (hereinafter referred to as *March 2006 Class I Area Modeling Supplement*).

Desert Rock Energy Facility Application for Prevention of Significant Deterioration Permit – Class II Area Modeling Update. Prepared for Sithe Global Power LLC by ENSR Corporation, ENSR Document No. 10784-001-0004b, June 2006 (hereinafter referred to as *June 2006 Class II Area Modeling Update*).

Electronic Modeling Archive

Copies of the modeling inputs and some outputs of the Calpuff modeling have been provided by EPA Region 9 to AMI on CD-ROM . EPA Region 9 has also provided the meteorological data for the years 2001 and 2002 on DVD.

Public Service Company of New Mexico

P. O. Box 2267
Albuquerque, New Mexico 87103
February 25, 1975

Mr. Don E. Tryk, P.E.
Supervisor, New Source Review Section
Air Quality Division
Environmental Improvement Agency
P. O. Box 2348
Sante Fe, New Mexico 87503

Dear Mr. Tryk:

Enclosed are responses to questions in your letter of February 7, 1975 to Mr. C. D. Bedford with attachments.

The construction schedule for Unit 1 as well as the proposed schedules for Units 3 and 4 are enclosed. These show that Units 3 and 4 have a tim table which is similar to the time table for Unit 1.

The "attached drawings" for the electrostatic precipitator specifications which were missing from the original application have been attached heret Please note that while these drawings are for Unit 3 they are also applicable to Unit 4.

The planned sulfur dixoide control system is the Wellman-Lord System and is almost identical to the sulfur dioxide control system for Units 1 and 2. As we discussed last week, I am supplying an information sheet on the Wellman-Lord System which shows similarities between the Units 1 and 2 systems and the Units 3 and 4 systems. This information along with that which the EIA already has on file for Units 1 and 2 should enable you to properly evaluate the current applications. Please note the amounts of sulfur and sodium sulfate on the information sheet do not correspond to the amounts shown on the application. The design assumptions are different from operating conditions in that "worst case" conditions are used for design purposes.

I am enclosing a page (V-10) from the boiler specifications which sets forth the air pollution requirements of the boiler design. As you can see the boiler shall not only be limited to 0.45 lb. of NO_x per million Btu of heat input but shall have included provisions to further reduce the NO_x emissions below 0.45 lb. per million Btu heat input.

Answers to the specific questions enclosed with your letter are as follows:

Copies of this material sent to
J. Bartlett on 2/27/75
RCW

1. Reference, Section 2, Fuel Usage -

   The maximum continuous heat available to the furnace, defined as: Usable heat in fuel plus sensible heat in combustion air minus one-half (radiation losses plus unaccounted losses plus contractor's margin) equals $5,582 \times 10^6$ Btu per hour. (See footnote 1)

2. Reference, Section 5, Air Pollution Control Equipment -

   The emission rates are dependent on the maximum continuous heat input as defined in number 1 above and as such would increase if the unit were operated at greater than rated capacity. (See footnote 1 and paragraph 6. Reference, Overall Generating Station)

   Our plans are to design the equipment to "do better" than the regulations require for particulate and sulfur dioxide removal efficiencies under almost all conditions. However we feel that the regulated levels are the proper levels for dispersion modeling to determine compliance with ambient air standards. We will meet the existing regulations for new coal burning equipment (#504, #602, #603) for all conditions and combinations of coal grades and power levels except as may be covered by other regulations of the EIB (i.e., upset, breakdown, scheduled maintenance, initial startup, etc.).

3. Reference, Section 6, Stack Data -

   The stack exit velocity at maximum continuous rating would be approximately 75 feet per second. The 175°F stack exit temperature is based on reheating flue gas out of the SO_2 scrubber to a point giving 175°F stack outlet temperature. The amount of reheat involved is controlled based on what temperature gas is received at the reheater. The approximate temperature drop in the stack would average 10° to 15° Fahrenheit based on current design. The velocity of the flue gas will vary as a function of input to the boiler (combustion calculations) but with the SO_2 system installed the temperature will be essentially constant. Normal power boilers without SO_2 controls may vary as much as 50° to 75° Fahrenheit with boiler load.

4. Reference, Section 9, Waste Product Disposal -

   Several errors appeared in this Section of the application. In the case of ash burial the boiler bottom ash was omitted. The differences in the sulfur and sodium sulfate amounts arose from different assumptions concerning operating conditions. The correct figures for Section 9 are:

Ash - 446,280 tons per year
Sulfur - 11,410 " " "
Na_2SO_4 - 7,400 " " "

5. Reference, Brown & Root Specification M-320 -

The answer to the question is yes. (See footnote 1 and paragraph 6. Reference, Overall Generating Station)

6. Reference, Overall Generating Station -

The San Juan Station could conceivably operate at the following maximum continuous heat input conditions:

Unit 1 @ 3418 x 10^6 Btu/hr.
Unit 2 @ 3313 x 10^6 " "
Unit 3 @ 5582 x 10^6 " "
Unit 4 @ 5582 x 10^6 " "

These conditions of service, however, result in severe degradation of equipment availability and would only be used under emergency conditions. (See footnote 1)

The normal conditions of operation would be as follows:

Unit 1 @ 3240 x 10^6 Btu/hr.
Unit 2 @ 3155 x 10^6 " "
Unit 3 @ 5295 x 10^6 " "
Unit 4 @ 5295 x 10^6 " "

Since maximum continuous heat input will occur only under emergency conditions, it is very unlikely that all four units would be operating at maximum continuous heat input simultaneously.

Footnote 1 -

The maximum continuous heat input of 5582 x 10^6 Btu/hr. corresponds with 5% overpressure and would only occur under conditions of extreme system demand. This situation would be of a very short duration (1/2 hour average - 2 hour maximum) and would occur infrequently.

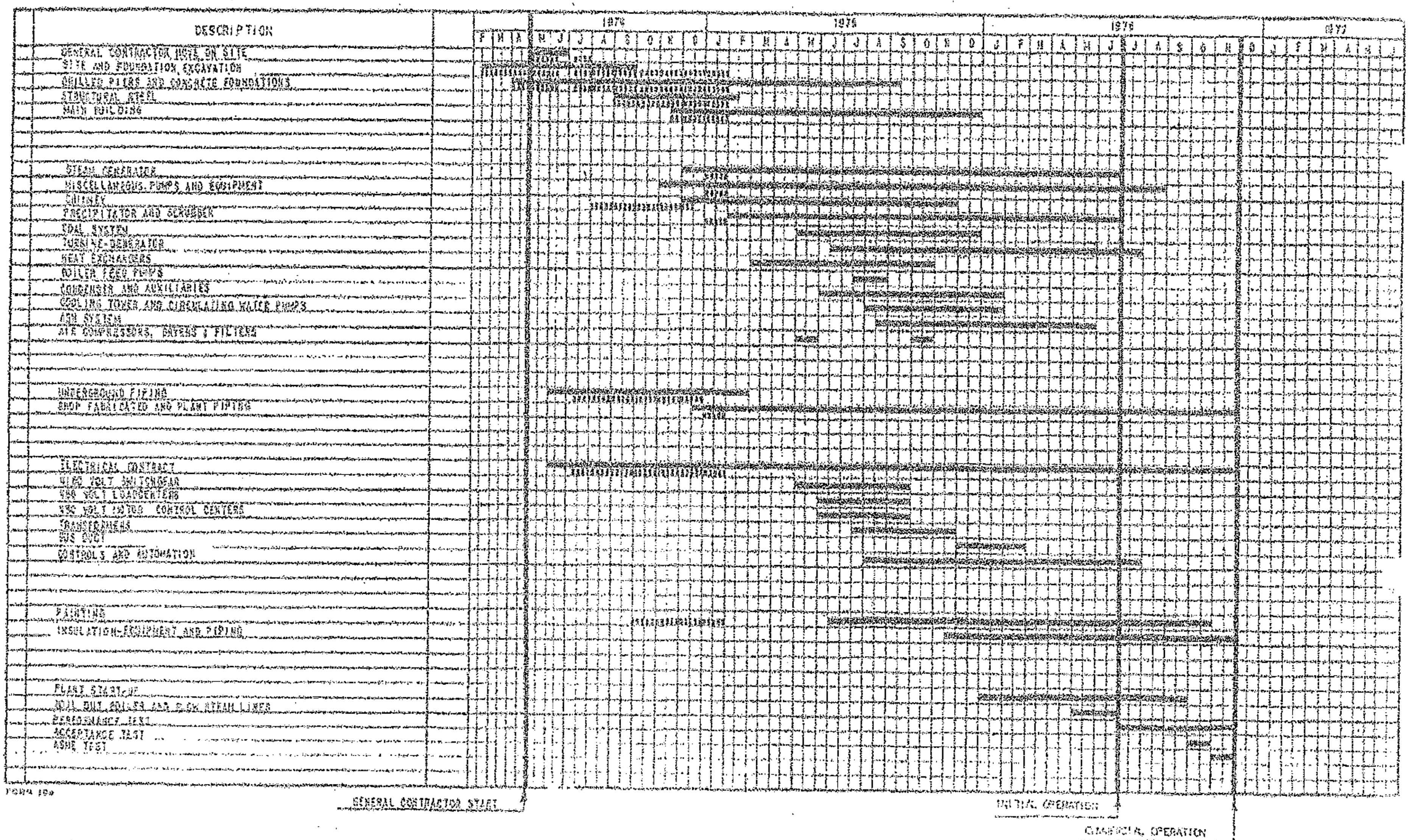
In reference to your table titled "Estimated Maximum Short-Term Emission Rates for San Juan Generating Station Units No. 3 and No. 4", if the intent is to estimate truly "short-term" emission rates, then the maximum continuous heat input of 5582 x 10^6 Btu/hr. should be used. The emission parameters which correspond to this heat input are as follows:

SCHEDULED
ACTUAL

CONSTRUCTION SCHEDULE
P.S.CO. OF NEW MEXICO
AND
TUCSON GAS AND ELECTRIC CO.
C-11800/C-11916

(CONSTRUCTOR - OPERATOR)
Stearns-Roger
January, 1975

CONSTRUCTION FOR UNIT 1
AT SAN JUAN STATION



MINUTES OF THE MEETING
OF THE
ENVIRONMENTAL IMPROVEMENT BOARD

May 9, 1975

A regularly scheduled meeting of the Environmental Improvement Board was called to order at approximately 10:00 a.m. by the Chairman, Mr. Roy S. Walker, in the 2nd floor Auditorium of the P.E.R.A. Building, Santa Fe, New Mexico.

Board members present were:

Mr. Roy S. Walker, Chairman
Mr. Kenneth G. Brown, Vice-Chairman
Mr. George E. Lambert, Secretary
Mr. William R. Atkins, Member

Also present were members of the Environmental Improvement Agency staff, the public and news services.

Mr. Douglas Fraser, Chief Attorney for E.I.A., suggested that agenda item number 3, setting of hearing date for requested review by the Board of the Agency's denial of a permit to construct San Juan Unit #4 by Public Service Company of New Mexico, be moved to agenda item number 8. Mr. Lambert moved that the agenda be accepted with Mr. Fraser's proposed change. Mr. Atkins seconded, and the motion passed unanimously.

Mr. Fraser stated that a news release had been sent out by the Agency on May 7, 1975, indicating the subject matters that would be discussed at the meeting. He added that this was in compliance with the Open Meetings Law.

Mr. Atkins moved that the minutes of the previous meeting be accepted. Mr. Lambert seconded, and the motion passed unanimously.

The request by Arizona Public Service Company and Public Service Company of New Mexico for an extension of time for filing their schedules of complaince for Air Quality Control Regulation No. 602 was the Board's next item of concern

Mr. Richard Cole, attorney for P.N.M., noted that Public Service Company of New Mexico was also requesting an extension of time within which to file its schedule of compliance for Air Quality Control Regulation No. 504. He said that since Regulation 602 is on appeal in the Court of Appeals, P.N.M. feels it inappropriate to file a compliance schedule without knowing the outcome of the appeal. He said that, if it suited the Board, P.N.M. would give them a report on the status of the appeal in six months or some other suitable amount of time. He added that P.N.M. is continuing with its SO_2 removal contracts and is not delaying any action as a result of the appeal.

Mr. Fred Hannahs, attorney for Arizona Public Service Company, stated that his company would agree with the request and reasons given by Mr. Cole. He added that the requests stem from a letter addressed to A.P.S. form the Agency recommending that they request an extension of time within which to file their schedule.

Mr. Robert Engel, attorney for the Air Quality Division of the Agency, said the Agency has no objection to the requests for extension of time by P.N.M. and A.P.S. and added that Mr. Cole's suggestion of a status report on the appeal might be a good one.

Mrs. Nancy Bartlit, N.M. Citizens for Clean Air & Water, asked if Arizona Public Service Company is continuing with its SO_2 removal schedule. Mr. Jim Weis, Arizona Public Service Company replied that A.P.S. is proceeding with its schedule of compliance with the Environmental Protection Agency.

Mr. Lambert moved to grant an extension of time to A.P.S. and P.N.M. until November 30, 1975 (six months), to cover both Regulations 504 and 602. Mr. Brown seconded.

Mr. Atkins asked if the granting of this extension would in any way waive the requirements of meeting the regulations by the specified dates set out in the regulation. Mr. Engel replied that it would not.

Mr. Brown moved to amend the motion to grant the extensions for six months or 30 days after the determination of the appeal, whichever comes sooner. Mr. Lambert accepted the amended motion, and it passed unanimously.

Blevins Lumber Company's proposed assurance of discontinuance from Air Quality Control Regulation No. 402 was the next topic of discussion. Mr. Engel noted that this assurance was proposed by Mr. Ogle C. Yates, general manager of Blevins Lumber Company and has not been approved by the Agency. He introduced Mr. Yates who read aloud his proposed assurance of discontinuance. The assurance proposed an effective date through May 31, 1976, thirty days prior to which the company would submit to the Board a proposed schedule of compliance.

Mr. Yates explained that his company had chosen utilization of its woodwaste rather than consumption. He admitted that the emissions from the burner are deteriorating rather than improving but said his company could not presently bring the burner into compliance due to economic reasons. He appeared before the Board a year ago because the Agency felt his company might be violating its present assurance of discontinuance, but he said his company has made improvements since then.

Mr. Brown asked how the company planned to keep the emissions at a minimum and to what extent they are exceeding the current regulation. Mr. Yates replied that the burner at times reaches 100% opacity. The current regulation requires 20% opacity. The current regulation requires 20% opacity. He added that he did not know how he would keep emissions at a minimum. Mr. Brown asked why he chose a deadline date of May 31, 1976. Mr. Yates replied that a company named Navajo Forest Products had agreed to use Blevins' refuse to make particle board, but that it would be some time in April of 1976 before they could start putting the woodwaste to use.

CONTROL STRATEGY DEMONSTRATION: NEW MEXICO AIR QUALITY CONTROL REGULATION 602, COAL BURNING EQUIPMENT--SULFUR DIOXIDE

4 February 1981

Prepared for

Region VI
Environmental Protection Agency

Prepared by

Air Quality Bureau
Health and Environment Department
New Mexico Environmental Improvement Division
Crown Building
725 St. Michael's Drive
Santa Fe, New Mexico 87503

SUMMARY

A Control Strategy Demonstration for amended New Mexico Air Quality Control Regulation (NMAQCR) 602 is performed by the New Mexico Environmental Improvement Division (EID). The Demonstration utilizes a non-guideline model, COMPLEX I, IOPT(25)=3, supplemented by site-specific ambient air quality data to demonstrate attainment of ambient SO_2 standards. A detailed substantiation of the applicability of this dispersion model in this locale is presented.

NMAQCR 602 regulates sulfur dioxide (SO_2) emissions from coal burning equipment in the state of New Mexico. Coal burning equipment affected by this regulation includes both the Four Corners and San Juan Generating Stations. The amended regulation provides for interim SO_2 emission limitations for the time interval 31 December 1982 through 31 December 1984, and permanent SO_2 emission limitations thereafter. The Control Strategy Demonstration is made on the basis of a full spectrum of worst case emission scenarios specified on the basis of the regulation to demonstrate attainment of primary ambient SO_2 standards for 31 December 1982 - 31 December 1984 and all applicable SO_2 standards thereafter.

The meteorological data base applied to this Control Strategy Demonstration is the four year data record, 1975-1978, collected at the 60m Four Corners Meteorological Tower. These data are demonstrated to be the most appropriate data record available for modeling purposes. Stability categories are determined by integrating cloud cover data from the Farmington Airport with concurrent wind data recorded at the Four Corners tower.

Preliminary modeling was performed to identify critical receptors and critical meteorological conditions. This analysis included runs of PRMAX AND MPTER over flat terrain and COMPLEX I over complex terrain. The outcome of the screening analysis was that the only possible

receptor-dispersion combination that could cause concentrations to approach ambient standards was stable impaction on high terrain. A finely resolved receptor grid was specified on the basis of the screening analysis for subsequent use in evaluating the ambient air quality effects of the imposition of the regulation.

Since the Coal Burning Equipment regulated by NMAQCR 602 are situated in complex terrain, and the screening analysis showed terrain impaction under stable conditions to be the limiting case, complex terrain models contained in the existing and proposed revisions to the Modeling Guidelines were investigated as to their appropriateness to the locale. Model comparisons between VALLEY and site-specific measured ambient data showed that the VALLEY Model significantly overestimated observed concentrations. In addition VALLEY could not be applied to evaluate protection of the Federal secondary standard. Following this comparison, both COMPLEX I and COMPLEX II with various terrain treatment options were subjected to performance evaluations, (1) with measured ambient concentrations collected at the Hogback monitor, the site-specific worst case complex terrain location and (2) with intensive tracer measurements, carried out in the vicinity of the Harry Allen Power Plant site, a complex terrain situation similar to the San Juan Basin.

The model selection process was carried out in accordance with the letter and spirit of the applicable modeling guideline documents. Both performance evaluations indicated that COMPLEX I, with IOPT(25)=3 most faithfully reproduced both the observed maximum concentrations and the full concentration frequency distributions, while maintaining an adequate margin of conservatism. The other COMPLEX I and COMPLEX II terrain modeling options all produced concentration distributions that appeared to be unnecessarily conservative in relation to both the Hogback data and the Harry Allen tracer data.

The worst case emissions scenarios together with the four years of Four Corners tower data were used as input to COMPLEX I, IOPT(25)=3 in conjunction with the refined receptor grid. For the 31 December 1982 to 31 December 1984 emissions scenarios (involving both the Four Corners and the San Juan plants at continuous full load) attainment of the primary SO_2 standard was demonstrated.

For the post-1984 emissions scenarios, attainment of the primary standard also was demonstrated, even under the assumption that the worst-case three hour emissions from both plants would occur continuously over the four-year meteorological data record. This assumption lead to the calculation of two exceedances of the secondary standard in one of the four meteorological data years, and no violations in any of the other three years. On the basis of a Monte Carlo simulation of scrubber design removal efficiencies, the frequency of a violation of the secondary standard was calculated to be about once in every 650,000 years, assuming continuous full load operation at both plants.

Ambient SO_2 collected continuously over 8 years by various organizations at identified worst case flat terrain and complex terrain locations in the areas surrounding the Four Corners and San Juan plants were reviewed. These data showed that violations of the primary and secondary SO_2 standards have never been recorded in this area, and that only one exceedance of the secondary standard has ever been recorded. Amended regulation 602 requires dramatic reductions in the levels of SO_2 emissions in relation to those occurring during the years when these ambient measurements were made. Therefore, it is concluded on the basis of the ambient air quality data, as well as on the basis of the results of modeling the worst case emission scenarios with the most appropriate dispersion model for a four year meteorological data record, that amended Regulation 602 will protect ambient air quality standards for SO_2 in the San Juan Basin.

TABLE 2-1. SULFUR DIOXIDE EMISSION LIMITATIONS ON FOUR CORNERS AND SAN JUAN GENERATING STATIONS REQUIRED BY NMAQCR 602

Generating Unit	Date of Enactment to December 31, 1981		December 31, 1981 to December 31, 1982		December 31, 1982 to December 31, 1984		After December 31, 1984	
	%Removal(a)	lb/hr(b)	%Removal(a)	lb/hr(b)	%Removal(a)	lb/hr(b)	%Removal(a)	lb/hr(b)
Four Corners Units 1, 2 and 3	50	N/A	50	N/A	60	6000	N/A	(d)
Four Corners Units 4 and 5	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(d)
Four Corners Plant-wide	N/A	N/A	N/A	N/A	N/A	N/A	72	17,900
San Juan Unit 2	60	N/A	72	N/A	72	N/A	72	N/A
San Juan Units 1, 3 and 4	(e)	N/A	(e)	N/A	(c)	N/A	(c)	N/A
San Juan Plant-wide	N/A	N/A	N/A	N/A	N/A	13,000	N/A	13,000

(a) Percent removal requirements are 30-day averages.
(b) The pounds per hour requirements are short-term averages (3-hour) which may be exceeded no more than once per year. Compliance is determined with the EPA Test No. 6.
(c) Emission limitations for San Juan Units 1, 3 and 4 are expressed in lb/MBtu. After December 31, 1982 the limitation is initially 0.55 lb/MBtu, which is equivalent to 67.5% SO_2 removal for average sulfur coal.
(d) Emissions limitations shall be submitted to EID prior to December 31, 1984. The sum for all five Four Corners units shall not exceed 17,900 lb/hr.
(e) Three-hour emission limitation is 1.2 lb/MBtu.

3 EMISSIONS CONFIGURATIONS

3.1 BACKGROUND INFORMATION

3.1.1 Design Characteristics of San Juan Flue Gas Desulfurization System

The Wellman Lord Sulfur Dioxide Recovery System is a regenerable system that uses a sodium-water solution to absorb SO_2 from a flue gas stream. The absorbing solution, containing sodium sulfite, reacts with the SO_2 to form sodium bisulfite. In the second step of the process, the SO_2 gas is thermally liberated from the solution, that is, the solution is heated, driving off the SO_2. This results in a regenerated absorber solution. In the scrubber system for San Juan Units 1 and 2, the SO_2 gas is reacted with natural gas to yield molten sulfur. In the scrubber system for Units 3 and 4, the SO_2 gas is reacted with air and water to yield sulfuric acid. In addition, both systems produce sodium sulfate as a by-product, which must be selectively removed from the solution by crystallization and then dried.

Both the end products, sulfur and sulfuric acid, and the by-product, sodium sulfate, are intended to be sold commercially.

3.1.2 Design Characteristics of Four Corners Flue Gas Desulfurization System

The flue gas desulfurization systems at the Four Corners Generating Station will consist of two basic designs. These are the Chemico Venturi scrubber system currently being upgraded at Units 1, 2, and 3 and the wet limestone scrubbers for Units 4 and 5 which are currently in the design stage.

3.1.2.1 Scrubber System for Units 1, 2, and 3

The Chemico Venturi scrubbers for Four Corners Units 1, 2, and 3 were originally installed for particulate removal and have recently been upgraded to optimize SO_2 removal. Each unit has two scrubber modules which treat the entire flue gas stream and which cannot be by-passed. The upgrading and optimization process is continuing in order to comply with the 72 percent, 30-day removal average required by section B of NMAQCR 602. It is estimated that the upgrading will result in mean hourly SO_2 removal efficiencies of 74 percent with a standard deviation of less than 5 percent.

It should be noted that because of the recent upgrade, these units cannot be operated at SO_2 removal efficiencies less than 50 percent for prolonged time periods without causing scaling problems in the scrubbers.

3.1.2.2 Scrubber System for Units 4 and 5

Scrubber design for Four Corners Units 4 and 5 calls for each unit to have four dedicated scrubber modules and one dedicated spare module. Each module will be designed to process 22 per cent of the flue gas at peak capacity. Normal bypass will be 12 percent of the total flue gas for each unit.

The scrubber system for each unit is being designed so as to reliably meet 72 percent removal. Each scrubber system is designed for a nominal

12/7

removal efficiency of 76 percent, an estimated median of 74 percent and an estimated 10th percentile of 72 percent.

3.1.2.3 Cumulative Probability of Removal Efficiencies

As indicated in the last two sections, the scrubber system for each of the five units is being designed or upgraded so as to individually meet the 72 percent, 30-day removal requirement. A result of this design is that individual unit removal efficiencies significantly below 72 percent are highly unlikely. Plant-wide removal efficiencies significantly below 72 percent are even more unlikely because of the necessity of having simultaneous scrubber upsets on all units. For example, in order to emit 17,900 lb/hour (52.4 percent SO_2 removal efficiency for average sulfur coal), which is the 3-hour emission limitation, it will be necessary to have a total of five Unit 4 and 5 modules completely out of operation and to have scrubber upsets on all of Units 1, 2, and 3. Such a condition is almost inconceivable.

In order to arrive at an estimate of the probability of having plant-wide removal efficiencies less than 72 percent, the cumulative frequency distribution of removal efficiencies was estimated for each generating unit on the basis of their design characteristics. These distributions are shown in Figures 3-1 and 3-2 for Units 1, 2, 3, and Units 4 and 5, respectively. On the basis of these individual cumulative frequency distributions, a cumulative frequency distribution for the plant-wide removal efficiency can be determined by means of a Monte Carlo method.

The Monte Carlo method was applied as follows. The hourly distributions set forth in Figures 3-1 and 3-2 were conservatively assumed to be average, thus for a rare 24-hour period the control level could conceivably be as low as 45 percent.

> Scenario 1C--Four Corners Units 4 and 5 at 80 percent load, remaining units as per notes (1) and (2) above. This was defined to evaluate the effects of a lower plume rise on the dispersion from these two units.

> Scenario 1D--Four Corners Units 4 and 5 at 60 percent load, remaining units as per notes (1) and (2) above. The purpose was the same as Scenario 1C.

All four scenario emissions subsets were used in the comprehensive modeling analyses.

3.2.3 Scenario 2 Emissions Configurations

For the post-1984 case, as per Table 2-1, the Four Corners plant is subject both to a 72 percent overall plant removal efficiency as a minimum 30-day rolling average and to a total plant-wide 3-hour emission limitation of 17,900 lb/hour. This latter figure corresponds to a removal efficiency of 52.4 percent at full load with coal of mean sulfur content. As discussed in section 3.1.2, this 3-hour emission rate has an extremely low probability of occurrence.

For the post-1984 case, as per Table 2-1, the San Juan plant also is subject to two requirements, i.e., 0.55 lb/MBtu for Units 1, 3, and 4, and 72 percent removal for Unit 2, and a plant-wide 3-hour emission limitation of 13,000 lb/hour. These two requirements also obtain for 1982 - 1984, but the 3-hour limitation was not incorporated into the Scenario 1 emissions sets because only the primary ambient air quality standard is of concern for that two-year period.

Two basic Scenario 2 subsets were defined, as follows:

- Scenario 2A--Four Corners units 1 to 5 and San Juan unit 2 at 72 percent control, and San Juan units 1, 2, and 4 at 0.55 lb/MBtu, with all nine units at full load.
- Scenario 2B--Four Corners at 17,900 lb/hour distributed to each unit in proportion to its load capacity, and San Juan at 13,000 lb/hour distributed in accordance with load capacity.

Scenario 2A is a reasonable worst case, not only because all nine units at the two plants are assumed to be at full load on a continuous basis, but also because for Four Corners about 80 percent of the time short term removal efficiencies will be greater than 72 percent, as was discussed in section 3.1.2. Consideration also was given to modeling at reduced load factors (with 72 percent control) as was specified for Scenarios 1C and 1D. However, the modeling runs for those cases yielded concentrations less than those for Scenario 1A. Therefore, full loads were considered to be the worst cases also for Scenario 2.

Scenario 2B can be thought of as an absolute worst case for each plant. Each plant has an extremely low probability of exhibiting this level of emissions, as was discussed in section 3.1.2, with a vanishingly small probability of the simultaneous occurrence of these levels at each plant.

Both Scenarios 2A and 2B were ultimately used in both the preliminary modeling analyses and the comprehensive modeling analyses.

(continuous) removal efficiency for Four Corners Units 1 to 3 of 45% (Scenario 1B), which is below the minimum 30-day average value of 60%. This latter scenario produces the highest concentrations of any of the four scenarios, yet the highest second high concentration for even this scenario in any of the four data years is less than 365 μg/m^3. The results in Table 7-1 also show that for these worst-case emissions scenarios, exceedances are calculated only at one receptor on the 42-point refined receptor grid. At every other receptor point, the highest calculated value in every year is less than 365 μg/m^3.

These results show that for the period 31 December 1982 to 31 December 1984, the Four Corners and San Juan generating stations operating under Regulation 602 will lead to attainment of the primary national ambient air quality standard.

7.2.2 Scenario 2 Results

Scenario 2 corresponds to emissions from the two plants after 31 December 1984. Two basic subsets of scenario 2 were developed for modeling purposes as discussed in section 3.2.2. Both Scenarios 2A and 2B have an extremely low probability of actual occurrence, particularly the latter.

Scenario 2A is defined by simultaneous full load conditions at both the Four Corners and San Juan plants, which will occur relatively rarely. It further assumes that emissions at each plant will correspond to the minimum 30-day rolling averages as required by Regulation 602. Most of the time, each plant will be operating at higher removal efficiencies, as is shown for the Four Corners plant by Figure 3-3, from which it

12/5

is seen that about 78% of the time the 72% removal value required by the regulation will be exceeded on a short-term (3-hour) basis.

Table 7-2 sets forth the summarized results for each of the four data years for Scenario 2A modeled by COMPLEX I, IOPT(25) = 3. The highest second highest calculated 24-hour concentration in any of the years is 139 $\mu g/m^3$, a value far below the primary standard of 365 $\mu g/m^3$. The highest second highest calculated 3-hour concentration is seen to be 949 $\mu g/m^3$, a value well within the secondary standard of 1300 $\mu g/m^3$. Full output listings for the scenario 2A results are provided in Appendix F. These results show that even with continuous full load conditions at both plants (a rare event) and simultaneous minimum 30-day removal efficiencies (an improbable event), attainment of the primary and secondary standards will occur.

Regulation 602 also places limits on 3-hour emission rates for both the Four Corners and San Juan plants, i.e., 17,900 lb/hr and 13,000 lb/hr, respectively. The actual occurrence of these emission rates at either plant is extremely unlikely, as was discussed in section 3.2.2 for Four Corners, even assuming continuous operation at full load, which of course will not occur. Nevertheless, in order to evaluate the ambient effects should such emission rates occur simultaneously, scenario 2B emissions also were modeled.

Table 7-3 summarizes the results of the Scenario 2B runs. Full output listings are provided in Appendix F. The calculated highest second highest 24-hour average concentration is 240, a value well within the primary standard of 365 $\mu g/m^3$.

12/5

TABLE 7-2. MAXIMUM CALCULATED 3-HOUR AND 24-HOUR AVERAGE CONCENTRATIONS USING COMPLEX I, IOPT(25)=3, FOUR YEARS OF FOUR CORNERS TOWER DATA, AND CONTINUOUS FULL LOAD FOR BOTH FOUR CORNERS AND SAN JUAN WITH SCENARIO 2A EMISSION RATES, BASED ON 72 PERCENT REMOVAL FOR FOUR CORNERS UNITS 1 TO 5 AND SAN JUAN UNIT 2, AND SAN JUAN UNITS 1, 3, AND 4 AT 0.55 lb/MBtu (67.5 PERCENT REMOVAL WITH AVERAGE SULFUR CONTENT)

Meteorological Data Year	Averaging Period	Worst Receptor			Second Worst Receptor		
		Maximum	Second Maximum	Receptor	Maximum	Second Maximum	Receptor
1975	24 hours	124	110	15	114	113	36
1976	24 hours	151	123	36	119	104	35
1977	14 hours	157	139	36	124	123	35
1978	24 hours	129	89	21	109	102	36
1975	3 hours	611	571	36	576	529	21
1976	3 hours	833	628	36	542	492	18
1977	3 hours	1106	949	36	869	795	35
1978	3 hours	605	349	40	494	474	36

TABLE 7-3. MAXIMUM CALCULATED 3-HOUR AND 24-HOUR AVERAGE CONCENTRATIONS USING COMPLEX I, IOPT(25)=3, FOUR YEARS OF FOUR CORNERS TOWER DATA, AND CONTINUOUS EMISSIONS OF 17,900 lb/hr (52 PERCENT REMOVAL WITH MEAN SULFUR CONTENT) FROM FOUR CORNERS AND 13,000 lb/hr (54 PERCENT REMOVAL WITH MEAN SULFUR CONTENT) FROM SAN JUAN

Meteorological Data Year	Averaging Period	Worst Receptor			Second Worst Receptor		
		Maximum	Second Maximum	Receptor	Maximum	Second Maximum	Receptor
1975	24 hours	191	191	36	179	160	15
1976	24 hours	254	211	36	197	157	41
1977	24 hours	265	240	36	209	203	35
1978	24 hours	191	130	21	185	174	21
1975	3 hours	1015	974	36	886	807	21
1976	3 hours	1422	1064	36	1025	823	42
1977	3 hours	1861	1626	36[a]	1436	1329	35[a]
1978	3 hours	994	591	40	842	814	36

a) Third highest value is 1062.
b) Third highest value is 968.

12 6

The calculated highest second high 3-hour value for the 1977 data year is 1626 $\mu g/m^3$, a value which exceeds the secondary standard. In the other three years, the calculated highest second high value is seen to be 1064 $\mu g/m^3$, a value well within the standard. In 1977, the two highest values at the second worst receptor also are seen to be greater than 1300 $\mu g/m^3$.

An inspection of the output listing (Appendix F) shows that the third highest value at any receptor in the 1977 year is 1062 $\mu g/m^3$ at receptor 36. Thus, only two exceedances are calculated to occur at any receptor. Further inspection of the output shows that the calculated exceedances at the two different receptors occur during the same two 3-hour periods, i.e., the 7th 3-hour on day 344 and the 3rd 3-hour period on day 211. A calculation of the probability that a violation of the secondary standard will actually occur can be made, if several assumptions are made, as follows.

First, assume that the Four Corners plant operates continuously at full load. Second, assume that all of the two exceedance concentrations result from the Four Corners SO_2 emissions. Because two separate exceedances were calculated, for the total emission rate from Four Corners of 17,900 lb/hr (2255g/s), the probability of an exceedance in any 3-hour period in the 1977 data year is 2/2920, or 0.00068.

The minimum total emission level which could cause two exceedances is $\frac{1300}{1626} \times 2255 = 1802$g/s. The uncontrolled emission rate for the Four Corners plant is 4682g/s. Therefore, the scrubbing efficiency associated with an emission rate of 1802g/s is $1 - \frac{1802}{4682} = 61.4\%$.

In order to find the probability that the scrubbing efficiency will be less than or equal to 61.4% it is necessary to construct a cumulative frequency distribution of SO_2 removal efficiencies. The Monte Carlo analysis discussed in section 3.2.2 was used to construct Figure 3-3, which represents the cumulative frequency distribution of removal efficiencies for the entire plant. For the removal efficiency value of 61.4% (or less), the associated probability extracted from the Monte Carlo simulation is 0.0018, or .18% of the time.

The probability of an exceedance in any 3-hour period in 1977 is a function both of the probability of the necessary (minimum) χ/Q value and the probability of the specified (maximum) scrubbing efficiency. If it (logically) is assumed that the meteorological conditions are independent of the removal efficiencies, then the probability of an exceedance in any particular 3-hour period is the product of the two probabilities, or $(.00068)\ (0.0018) = 1.2 \times 10^{-6}$.

If the probability of an exceedance in any 3-hour period is 1.2×10^{-6}, the probability of a violation (two exceedances) in any year is given by the following expression, based on equation 10, set forth in the ExEx Report (SAI, 1980):

$$\Pr(\text{violation}) = 1-[(1+2919p)\ (1-p)^{2919}],$$

where p is the probability of an exceedance in any 3-hour period. When $p = 1.2 \times 10^{-6}$, Pr(violation) is 6.1×10^{-6}. The other three data years (1975, 1976, and 1978) indicated a zero probability of violation (see Table 7-3). Therefore, for the four-year meteorological data period, the calculated probability of violation in any year is about 1.5×10^{-6}, or once in every 650,000 years. Even this calculated probability is based upon the assumption of full load on a continuous basis, and thus it is clear that any violation of the secondary standard has a vanishingly small probability of occurrence.

These Scenario 2A and 2B modeling results thus demonstrate that under Regulation 602, the Four Corners and San Juan generating stations will not cause any violations of the primary and secondary national ambient air quality standards in the post-1984 period.

Four Corners Timeline for SO_2 regulation development

9/71—EIB held public hearings to consider 33% control or 77% control requirement for all power plants. EIA proposed that 33% control would be sufficient to meet the NAAQS.

1/27/72—NM SIP submitted

3/25/72—NM EIB adopts AQCR 602—requires 39% control on Unit 2 at SJGS

5/31/72—EPA approves NM SIP with exceptions for compliance schedules, NSR and source surveillance. EPA says SO_2 in 4 Corners AQCR meets NAAQS.

7/27/72—EPA says NM SIP does not provide for attainment of the SO_2 NAAQS in Four Corners AQCR. EPA extends attainment date to 7/27/74. EPA proposes rule to require APS and PNM have 70% control of SO_2 emissions by 7/31/77 in order to attain and maintain the NAAQS for SO_2. The control efficiency requirement is based on modeling results.

9/6/72—2 day hearing on EPA's proposed regulation in Santa Fe. PNM testifies that 70% control is not possible by 7/31/77.

3/23/73—EPA promulgates regulation requiring 72% control by 3/15/76.

7/23/73—PNM submits compliance schedule to comply by 7/31/77.

10/29/73—PNM submits variance petition to EIB for compliance with AQCR 602.

12/18/73—EPA proposes changes to regulation:

1.) allow PNM and SJGS to obtain credit for reducing SO_2 by pretreatment and reducing power output
2.) Emission limit would be averaged over total plant, not each emissions unit
3.) Require all SO_2 control at maximum practicable efficiency regardless of load
4.) Final compliance date moved to 7/31/77

1973—PMN and Four Corners put a monitoring network in place. They contend that, according to the monitoring, NAAQS are not exceeded now, so 70% control is not required. APS performs airborne plume tracking with plant at full load demonstrating NAAQS is not exceeded.

1/10/74—EIB grants variance to PNM from AQCR 602.

2/6/74—EPA hearing on proposed rule change. PNM testifies that monitoring shows the standard is not and will not be violated, "at least in areas that are populated". PNM also testifies that extensions are needed to put controls in place, and even at that, they might not be technically feasible. APS challenges the NOAA model that is the basis for the

70% control requirement. EID testifies that they intend to modify the NM SIP for power plant control to adopt a regulation that will allow attainment of the NAAQS. EID indicates they may seek 80% control of SO2 emissions. Citizens for Clean Air and Water object to APS seeking only 70% control while PNM has indicated they might achieve 90% control.

1/74—APS files compliance schedule based on a compliance date of 7/31/77 to add scrubber and absorber to Units 4 and 5, test and modify existing Venturi scrubbers on Units 1,2 and 3.

2/74—PNM and APS begin a "field monitoring study".

3/21/74—EPA promulgates its revised regulation

12/74—EIB approves regulation 602B requiring 65% control on smaller coal burning equipment (250-3000 MMBtu) and 85% control on units over 3000 MMBtu. After 7/31/79, the control requirement becomes 90%. EIB reasons for adoption:

- Protects welfare, property and public interest
- Allow for more growth in the Four Corners area, so the power plants don't "use up" all of the standard
- NM must be at least as stringent as the EPA regulation so that NM can regain authority
- These control efficiencies are technically achievable
- These higher control efficiencies are necessary to protect visibility

10/3/75—NM revises SIP for regulation 602B adopted by the EIB

2/24/76—EPA approves NM SIP, revokes its federal regulation

4/6/76—NM Court of Appeals invalidates parts of 602B requiring control efficiencies on coal burning equipment by majority with 1 dissenting opinion:

- EIB cannot plan for growth by placing limits on one industry to allow for other industry.
- EIB has no authority to require at least as stringent control as EPA as federal rule is primary (the court seemingly did not understand that NM was trying to regain authority)
- APS presented evidence that only 35% control is necessary to meet the NAAQS
- EID testimony from Bruce Nicholson only showed that APS is now and will be exceeding the NAAQS at 30% control. Not sufficient evidence that higher efficiency is necessary.
- There is no evidence that visibility will be impaired as SO2 is a colorless gas.

5/76—EIB requests hearing on appeal decision from NM Supreme Court. Court denies request.

6/76—EIA, Energy Resources Board, Department of Development and APS work on development of AQCR 602. Proposed regulation called for 60% removal of SO2 from existing equipment.

8/17/76—EPA revokes approval of NM SIP.

8/24/76—EID asks EPA what minimum degree of control would be approvable to EPA for incorporation in the NM SIP. EID begins development of AQCR 602 in coordination with APS. It is decided that 60% control over the entire plant is sufficient.

11/12/76—EID proposed new 602B requiring 60% control on existing equipment. EIB tabled motion while awaiting legislative guidance (amendment of the AQCA) as to what their authority was.

1/77-2-77—State legislature fails to amend the AQCA.

4/15/77—APS applies for variance to 602. EIB grants variance with conditions:

1. Variance is for 1 year or until 602B is amended.
2. If any violations of SO2 are monitored, variance is terminated.
3. APS must install a monitor SE of the plant and on Mesa Verde Plateau, if feasible.
4. APS shall notify EIA of any violations of the AAQS.

APS argued that there was currently no valid regulation controlling SO2 emissions from units #4 and 5 except the existing 1972 regulation requiring 33% control (that EPA disapproved in the SIP submittal). APS essentially wanted a variance from complying for units #1-3. APS testified that modeling the current APS emissions (facility-wide 8% control) predicted potential NAAQS violations on the Hogback, but this is not an inhabited area, so there is no potential harm to human health in granting the variance. APS also testified that they were having problems with new scrubbers and might achieve 60% control eventually, but not by the 1977 deadline in 602. APS testified that EPA now believed that 40% control would be adequate to meet the NAAQS. Bruce Nicholson of EID modeled APS only with units #1-3 @ 30% control, units 4-5 uncontrolled (current conditions). Assuming full load, in flat terrain near the plant, predicted 24-hour average concentrations ranged from 0.13 –0.24 ppm. The 24-hour NAAQS is 0.14 ppm. At 70% load, predicted concentrations were 0.12-0.22 ppm. In high terrain, predicted concentrations were 0.12-0.3 ppm. He presented the following comparison with other 24-hour average modeling results for current APS emissions:

1973 EIA modeling: 0.19 ppm in flat terrain, assuming 30% control on units 1-3

1976 4 Corners EIS: .17-0.19 ppm in flat terrain, 0.14 in complex terrain (predictions adjusted for current APS emissions)
1973 SO2 standards hearing, PNM testimony: 0.31 ppm with SJGS and APS uncontrolled; APS testimony: 0.15 ppm with APS controlled
1975 Revised 4 Corners Cumulative impact statement: 0.29 ppm in complex terrain
1975 EPA analysis: at least 0.12 ppm in the Hogback, 0.12-0.3 ppm on Mesa Verde Plateau

5/77—EID proposes new 602B to the EIB. APS disapproves of proposal.

6/77—NMCCAW and APS propose different versions of 602B to the EIB.

6/77—Navajo Tribal Council approves resolution to require permits and receive fees for sulfur emissions on the Navajo Nation. Annual fee would be $25 million for APS in 1982 with 60% control or $3.8 million annually if APS controlled to 90% (using glue gas desulfurization).

7/77—EID and APS work to iron out their differences and withdraw previous proposals to the EIB. Joint EID/APS proposal for 602B submitted to the EIB.

7/77—NM AG opinion that EIB must consider the AAQS in approving regulations, and cannot approve regulations that are more restrictive than necessary to meet the AAQS. The EIB can consider all existing sources and reasonably anticipated growth in approving regulations.

8/77—EIB hearings to determine percent control of SO2 required at APS 4 Corners to meet the NAAQS and NMAAQS. EID/APS offer joint proposed 602:

1.) 602A stays the same (78-80% control required for new equipment
2.) 60% control required for existing equipment by 1/1/78
3.) 602C allows flexibility in obtaining 60% control average over the entire facility. NOI for 602C would be due 1/1/78. Proposed emission unit limits due 11/30.80. Compliance with limits must be achieved by 11/30/82. In the interim, a supplemental control system must be utilized. This is comprised of air monitors and procedure for curtailing emissions if an exceedances is possible.

Navajo Nation (Harold Tso and Michael Willingham) testify that 90% control is reasonable economically because the proposed Navajo Nation sulfur fee for APS will be reduced to $3.8 million annually at this control level, whereas at 60% control, the Nation will charge APS $25 million annually.

PNM testifies that although 602A requires 80% control, they design their controls to achieve 90% so that they have a margin of safety. Units 1 and 2 will achieve 90% control by 12/77. Units 3 and 4 will also achieve 90% when operational. PNM is opposed to any change to 602A requiring 90% because they will not have a margin of safety at 90% control requirement. PNM also opposes being part of the supplemental control system because PNM will not contribute significantly to any violation, they do not believe EPA will accept such a plan, and they don't want to have to curtail their operation.

WESCO and Plains Electric testify that they agree with the APS/EID proposal. They oppose the NMCCAW proposal.

League of Women Voters, Durango Chamber of Commerce, Shiprock Chapter and the Farmington Jaycees testify in opposition to the APS/EID proposal.

Ken Hargis (EID) testifies that 60% plantwide average control is necessary to meet the NAAQS. Modeling predicts that PNM could contribute to a NAAQS violation currently. The APS/EID proposal will attain and maintain the NMAAQS, which is a more restrictive standard than the NAAQS, therefore, the proposal will meet the requirement to attain the NAAQS. EPA has indicated that they believe 60% plantwide average control will be adequate to maintain the NAAQS. Hargis testified that although monitors have shown no violations of the NAAQS, there may be violations occurring where there are no monitors.

Bruce Nicholson (EID) testified on the modeling. He included APS, PNM, WESCO, El Paso and the proposed PNM Bisti plant (a 2000 MW coal-fired power plant). He did not include the proposed Navajo plant. He used Turner's Gaussian model. He assumed 60% control on all APS units and unit 2 at SJGS (existing) and 80% control on units 1,3 and 4 at SJGS (new). His modeling showed compliance with the NAAQS and NMAAQS. Since 60% control was required on existing equipment to show compliance, it follows that the NMAAQS and NAAQS are now being exceeded and a monitoring system/curtailment system is necessary. In APS' cross-examination of Bruce, the point comes out that since PNM will actually achieve 90% control on all units at SJGS, the 60% control requirement for the existing APS units is overly conservative. In further cross-examination, Bruce testifies that he modified the EPA Valley Model (and renamed it the "Sector-averaging Model") so that plume reflection was no longer included. This reduced predicted impacts by a factor of 2, on average. Under cross, Bruce testified that he couldn't remember why he testified that 70% control on existing units was necessary to meet the NAAQS at the '74 EIB hearing.

Frank Courtenay (APS consultant) testified that he used the EPA Valley Model unmodified in his modeling analysis, which demonstrated that the APS/EID proposal meets the NAAQS. He discussed the use of the model with EPA. Joe Tikvart of OAQPS approved the use of the model for this analysis. Frank did not modify the model as Bruce did; however, he did not model for "F-stability class", which is the EPA recommendation. Frank's methodology would eliminate prediction of concentrations under the most stable atmospheric conditions [Mary Uhl note: highest concentrations would occur under F-stability]. Frank testifies that current emissions from APS and PNM do cause exceedances of the NAAQS in the Hogback and in simple terrain near the APS plant.

Dr. Taylor (APS) testifies on SO2 monitoring in the 4 Corners area. He says that none of the 8 monitors currently in the area has detected a violation of the NAAQS. On cross, he is asked about Dr. Bob Jacko's (Purdue University) recommendation that 24 monitors are necessary to sufficiently monitor for SO2 around a power plant. [Mary Uhl note: I played tennis in high school with Bob Jacko's daughter.] Dr. Taylor disagrees with Dr. Jacko, he testifies that 10 monitors are sufficient and APS objects to placing a monitor on the Hogback, as it is a rock and there is nothing to protect there.

Dr. Clyde Hill (U of Utah) testifies about SO2 damage to plants. There is no evidence of SO2 injury to plants in the Four Corners area.

At end of 5 days of hearings, EIB decides it needs to hear more evidence. EID testifies that 60% control would cost APS $30-40 million less than previous regulations and that the impact will be the same.

11/21/77—EIB holds 2 days of hearings. Citizens and the state testify. APS declines to testify and offers a settlement to the citizens because they think the EIB might adopt a regulation requiring more than 60% control. Negotiations followed. The parties presented to the EIB for consideration the following:

1. APS agreed to install controls to meet 67.5% control.
2. All parties would propose the EIB adopt a regulation with this control efficiency.
3. Agreement that there would be monitoring and if monitoring showed that 67.5% was sufficient to meet the NAAQS and NMAAQS, the regulation would remain unchanged.
4. If monitoring showed the control efficiency was insufficient to meet the NAAQS and NMAAQS, the EIB would be petitioned to change the reg.

11/77-6/78—Monitoring protocol was negotiated with all parties.

6/1/78—PNM accuses APS of not being sincere about following through on monitoring.

6/9/78—EIB met to consider and approve the monitoring protocol and approved AQCR 602B with 67.5% control requirement for APS 4 Corners and SJGS. Cost of equipment was estimated to be $220 million.

7/78—PNM met with APS and concluded that APS was going to delay the monitoring and that APS wanted to use monitoring to reduce the SO2 control requirement. APS subsequently petitioned the EIB (in violation of the agreement) to lower the control requirement in AQCR 602 based on APS' independent monitoring study. They contend that their monitoring shows that the present regulation requires more control of SO2 than is necessary to meet NMAAQS and NAAQS.

1978-1979—PNM attains 67.5% control efficiency to meet the regulation (which ensures compliance with the NAAQS and NMAAQS).

1980—EID files injunction in District Court against APS, claiming they have not complied with negotiated agreement of 1977.

1980—parties negotiate new agreement requiring 72% control of SO2 emissions from APS 4 Corners Plant by 12/31/84. "Completion of this latest environmental improvement project will mean that the plant should be in compliance with all applicable State and Federal SO2 Regulations." The cost of the new control equipment will be passed on to the consumer.

State of New Mexico
Environmental Improvement Board
Crown Building, P. O. Box 968
Santa Fe, New Mexico 87503

RECEIVED
'78 JUN 13 AM 11: 02
STATE COMMISSION OF PUBLIC RECORDS & ARCHIVES

AIR QUALITY CONTROL REGULATION 602

Air Quality Control Regulation Number 602, adopted by the Environmental Improvement Board on March 25, 1972; amended on December 13, 1974, is amended June 9, 1978 to read as follows:

602. COAL BURNING EQUIPMENT - SULFUR DIOXIDE. --

A. No person owning or operating new coal burning equipment having a power generating capacity in excess of 25 megawatts or a heat input of greater than 250 million British Thermal Units per hour shall permit, cause, suffer or allow sulfur dioxide emissions to the atmosphere in excess of .34 pounds per million British Thermal Units of heat input (higher heating value).

B. Except as provided in Section C, no person owning or operating existing coal burning equipment having a rated heat capacity greater than 250 million British Thermal Units (higher heating value) per hour shall permit, cause, suffer or allow sulfur dioxide emissions to the atmosphere in excess of .53 pounds per million British Thermal Units of heat input (higher heating value). This section shall become effective July 9, 1978.

C. Any person owning or operating an existing coal burning station having units with a rated heat capacity greater than 250 million British Thermal Units (higher heating value) per hour:

1. may file a written statement of intent to submit individual emission limits for each unit of the station such that total emissions from the station will not exceed .53 pounds per million British Thermal Units of heat input (higher heating value) when all units are operating at maximum capacity. Such written statements of intent must be filed with the Board on or before July 9, 1978. Any person submitting a timely written statement of intent shall not be required to comply with the provisions of Section B. Any person not submitting a timely written statement of intent shall comply with the provisions of Section B;

2. if, having submitted a statement of intent as provided in Subsection C.1, shall file with the Board on or before December 31, 1980, a petition stating proposed individual emission limits for each unit within the station such that total emissions from the station will not exceed .53 pounds of sulfur dioxide per million British Thermal Units of heat input (higher heating value) when all units are operating at maximum capacity. Individual emission limits for each unit shall be expressed in terms of pounds of sulfur dioxide per million British Thermal Units of heat input (higher heating value); and

3. having received from the Board approval of the proposed individual unit emission limits, shall not permit, cause, suffer or allow sulfur dioxide emissions to the atmosphere from any unit in excess of the approved individual emission limits for each unit.

G. No person owning or operating existing coal burning equipment subject to this regulation shall permit, cause, suffer, or allow operation of the existing coal burning equipment without normally maintaining in good operating condition at least one monitor, approved by the Department which shall continuously measure and record sulfur dioxide concentrations in the gases within the stack from which the gases are released to the atmosphere. Instruments and sampling systems installed and used pursuant to this section shall be calibrated in accordance with the methods prescribed by manufacturer's recommended zero adjustment and calibration check procedures at least once every 24 hours of operation, unless the manufacturer specifies or recommends calibration checks more frequently; provided, however, that no calibration and adjustments shall be required during periods when the coal burning equipment is not operating. The reference method shall be consistent with the method for manual sampling of sulfur dioxide specified in Section F.

H.1. To aid the Department in determining compliance with this regulation, persons owning or operating coal burning equipment subject to this regulation shall, after July 9, 1978 or December 31, 1982, whichever is its compliance date, submit quarterly reports to the Department for the periods January 1 through March 31, April 1 through June 30, July 1 through September 30, and October 1 through December 31 of each year, each report to be received by the Department within forty-five days of the end of the quarterly period. The quarterly reports shall contain the following

a) hourly averages of the concentrations of sulfur dioxide, expressed in parts per million, in the gases which are being emitted to the atmosphere, except for periods of instrument calibration and zero adjustments;

b) hourly averages of the percent excess oxygen in the gases coming from the coal burning equipment;

c) rate of heat input (higher heating value) into the coal burning equipment calculated for each day; and

d) daily average or daily composite percent sulfur and heat content (higher heating value) of the coal utilized by the coal burning equipment determined for each day.

2. Upon request, the Department may approve alternative methods of monitoring and reporting the information specified in Subsection H.1.

I. 'new coal burning equipment' means coal burning equipment the construction of which is commenced after September 1, 1971;

2. 'existing coal burning equipment' means coal burning equipment that was fully constructed and operational or under construction prior to September 1, 1971;

3. 'existing coal burning station' means one or the combination of two or more units of existing coal burning equipment at one location;

4. 'construction' means fabrication, erection, or installation of an affected facility; and

5. 'commenced' means that an owner or operator has undertaken a continuous program of construction or that an owner or operator has entered into a binding agreement or contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction.

I hereby certify that Air Quality Control Regulation 602, as covered in this text was amended by the Environmental Improvement Board on June 9, 1978.

Kenneth G. Brown

Kenneth G. Brown, Chairman

N.M. ENVIRONMENTAL IMPROVEMENT BOARD
NOTICE OF PUBLIC HEARING
ON PETITION FOR VARIANCE
FROM AIR QUALITY CONTROL REGULATION 602.A

COAL BURNING EQUIPMENT - SULFUR DIOXIDE

The New Mexico Environmental Improvement Board will hold a public hearing on July 14, 1978 beginning at 1:30 p.m. in the PERA Building Auditorium in Santa Fe. The hearing is to consider the variance request of Public Service Company of New Mexico for San Juan Unit 3 from AQC Regulation 602.A.

Statements to be incorporated in the public record may be sent to Environmental Improvement Board, P. O. Box 968, Santa Fe, New Mexico 87503 prior to the hearing or be presented at the hearing, orally or in writing. Statements should be entitled: "Statement for Public Record regarding Variance Petition of Public Service Company of New Mexico". Those who wish to cross-examine witnesses at the hearing must submit a written request to do so to the EIB by 4:00 p.m., July 12, 1978.

ss/Kenneth G. Brown, Chairman

BEFORE THE

NEW MEXICO ENVIRONMENTAL IMPROVEMENT BOARD

SANTA FE, NEW MEXICO

IN THE MATTER OF:	)
	)
THE VARIANCE REQUEST OF THE PUBLIC SERVICE COMPANY OF NEW MEXICO FOR ITS SAN JUAN COAL-FIRED GENERATING UNIT NO. 3 FOR A VARIANCE THROUGH MAY 1, 1982.	)))))

TRANSCRIPT OF PROCEEDINGS

July 14, 1978

BE IT REMEMBERED that on to-wit, the fourteenth day of July, 1978, this matter came on for hearing before the New Mexico Environmental Improvement Board, sitting at the P.E.R.A. Auditorium, P.E.R.A. Building, Santa Fe, New Mexiço, at the hour of two fifty o'clock in the afternoon.

(2) Manager, Corporate Planning - 1971-73.

(3) Assistant and then Manager, Engineering - 1969-71.

(4) Senior Engineer, System Studies - 1967-69.

(5) Special Projects Engineer - 1963-67.

Sandia Corporation:

(1) Technical Staff Member - 1962 and 1963.

I have also been a member of the following committees or forums:

(1) Western Systems Coordinating Council, Technical Studies Subcommittee, Planning Coordination Committee, Environmental Committee,

(2) New Mexico Power Pool, Engineering Committee 1969 to 1974 (Chairman - 1971 to 1974)

(3) E.E.I. Rate Research Committee

(4) Western Energy Supply and Transmission Associate (WEST), Engineering and Planning Committee - 1973 to 1978 (Chairman - 4/76 to 4/78) Management Committee - 1978

Q. Mr. Bedford, would you briefly outline the purpose of your testimony?

A. Public Service Company of New Mexico, individually and as agent for Tucson Gas and Electric Company, is requesting this variance based upon the provisions of Section 12-4-8. The requested variance extension is for sulfur dioxide control on San Juan Unit Number Three for the period of May 1, 1981, until May 1, 1982.

San Juan Generation Station, when completed, will consist of four generating units. These units will be owned jointly by Public Service Company of New Mexico and Tucson Gas and Electric, except for Unit Number Four, which will be owned solely by P.N.M. The first unit began commercial operating in November, 1973, and the second unit began commercial operation in December of 1976. The third and fourth generation units will begin commercial operation in May of 1979 and May of 1982, respectively.

P.N.M. began selection of a sulfur dioxide removal system in 1972, which coincided with the adoption by this Board of Air Quality Control Regulation 602. In February of 1974, P.N.M. selected a system for installation of San Juan Units One and Two. It is the Wellman-Lord sulfur dioxide removal process, which became operational on Unit Number One in April of 1978 and became operational on Unit Number Two in July of 1978. The system is designed for ninety percent removal and this process is the first of its kind installed on coal-fired generating units the size of San Juan Units Number One and Two in the world. This prototype system on Unit One and Two cost P.N.M. and T.G.& E. in excess of one hundred twenty million dollars.

Desert Rock Energy Co., PSD Appeal 08-03
Conservation Petitioners' Exhibits

EXHIBIT 43

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 300
DENVER, CO 80202-2466
Phone 800-227-8917
http://www.epa.gov/region08

APR 12 2002

Ref: 8P-AR

Terry L. O'Clair, Director
Division of Air Quality
Environmental Health Section
North Dakota Department of Health
P.O. Box 5520
Bismarck, ND 58506-5520

Dear Terry:

EPA has reviewed the draft North Dakota revisions to the State Implementation Plan (SIP) and Air Pollution Control Rules, as submitted by you with a letter dated February 14, 2002. Our comments for the April 19, 2002 public hearing are detailed in the attachment to this letter. In particular, please note our comment #17 regarding approvability concerns with the proposed addition of Class I significant impact levels to Chapter 33-15-15, Prevention of Significant Deterioration of Air Quality. As a reminder, a written response to EPA's comments, and all other comments received, is required to meet the completeness criteria outlined in 40 CFR Part 51 Appendix V and must be included in the formal Governor's submittal of these revisions to the SIP once they are finalized.

As you are aware, there are several proposed revisions that are not appropriate for incorporation into the North Dakota SIP for various reasons. These reasons are listed below along with the proposed North Dakota provisions that fall into each category.

1. Programs for which EPA should delegate authority to the State: Chapter 33-15-12 Standards for Performance for New Stationary Sources (New Source Performance Standards - NSPS) and any related emission guideline plans, Chapter 33-15-13 Emission Standards for Hazardous Air Pollutants (40 CFR Part 61 National Emission Standards for Hazardous Air Pollutants - Part 61 NESHAPs), and Chapter 33-15-22 Emission Standards for Hazardous Air Pollutants for Source Categories (40 CFR Part 63 National Emission Standards for Hazardous Air Pollutants - Part 63 NESHAPs);
2. Programs which EPA has already approved at the State level: Chapter 33-15-14-06 Title V Permit to Operate (8/16/99) and 33-15-21 Acid Rain Program (10/11/95); and
3. Rules that are not generally related to attainment or maintenance of the National Ambient Air Quality Standards (NAAQS): Chapter 33-15-24 Standards for Lead Based Paint

Activities.

Any necessary follow-up on the above proposed revisions will be handled separately, with the exception of our comments on Chapters 33-15-12 Standards of Performance for New Stationary Sources and 33-15-14-06 Title V Permit to Operate, which are included below.

We appreciate the opportunity to provide comments for your public hearing. If you have any questions on EPA's comments, please call me at 303-312-6005, or have your staff call Amy Platt at 303-312-6449.

Sincerely,

Richard R. Long
Director
Air and Radiation Program

Enclosure

cc: Tom Bachman, ND Department of Health
Chris Shaver, NPS
Sandra Silva, USFWS

bcc: Kathleen Paser, 8P-AR
Megan Williams, 8P-AR
Sara Laumann, 8RC

ATTACHMENT

COMMENTS FOR NORTH DAKOTA'S APRIL 19, 2002 PUBLIC HEARING

Chapter 33-15-01, General Provisions

1. Although 33-15-01-07, Variances, is not the subject of the current revisions, please be advised that this provision should be removed from the Federally approved SIP. Section 110(i) of the Federal Clean Air Act, as amended, prohibits the suspension of any requirement of an applicable SIP from being taken with respect to a stationary source by a State or the Administrator of EPA, except by SIP revision under section 110(a) (and a few other exceptions). When you make your formal Governor's submittal of the final revisions, please request that EPA remove this provision from the SIP.

2. In addition to the federally enforceable monitoring or testing methods in 40 CFR parts 50, 51, 60, 61, and 75 listed as presumptively credible evidence in 33-15-01-17.2.b(1), North Dakota should add federally enforceable monitoring or testing methods from 40 CFR part 63. However, since EPA does not approve the "presumptively credible evidence" language in any newly approved credible evidence rules, we suggest that North Dakota instead revise the language in Chapter 33-15-01-17.2.a. and b. to simplify it and make it more consistent with other states by replacing the current language with the following: "For the purpose of submitting compliance certifications or establishing whether or not any person has violated or is in violation of any standard in the North Dakota state implementation plan, nothing in the North Dakota state implementation plan shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test or procedure had been performed."

Chapter 33-15-05, Emissions of Particulate Matter Restricted

3. It is not clear whether the exemption language proposed in 33-15-05-02.1.c. would result in an increase in emissions. Please define "gaseous fuels" and "other gaseous fuels." To be approvable, the State will need to demonstrate that this proposed provision will not interfere with the NAAQS, Prevention of Significant Deterioration (PSD) increments, or any other Clean Air Act requirements.

4. The proposed language in 33-15-05-03.3.1. removes standards for salvage incinerators. Please explain what the State considers a "salvage incinerator" so we can determine whether removing standards for them is acceptable. To be approvable, the State needs to demonstrate how it will ensure that these facilities are not interfering with the NAAQS, PSD increments, or any other Clean Air Act requirements.

5. It is not clear why the proposed language in 33-15-05-03.3.4.c. to change the temperature requirement from 1600 to 1400 degrees Fahrenheit in a secondary chamber of a

crematorium is acceptable. EPA recommends minimum secondary chamber temperatures of 1600-1800 °F based on design types as follows: 1600 °F for units 500 lb/hr and under, in-line and retort types; 1800 °F for units greater than 500 lb/hr, multi-chamber type (see page 47 of the enclosed Regulatory Alternatives Paper, prepared by The Incinerator Work Group of EPA's Industrial Combustion Coordinated Rulemaking (ICCR) Coordinating Committee, September 8, 1998). To be approvable, the State needs to demonstrate that this proposed change will not interfere with the NAAQS, PSD increments, or any other Clean Air Act requirements.

6. The proposed last sentence in 33-15-05-03.4.e., regarding deviations from charging procedures for crematoriums, should be revised to read "......approved by the department **and EPA.**"

7. The proposed first sentence in 33-15-05-04.1., regarding alternative methods of measurement, should be revised to read ".....as approved by the department **and EPA....**" In addition, we note that 33-15-05-04, Methods of measurement, outlines methods used to determine compliance with sections 33-15-05-01 and 33-15-05-02. What will be the method for determining compliance with sections 33-15-05-03.2. and 33-15-05-03.3.?

Chapter 33-15-06, Emissions of Sulfur Compounds Restricted

8. We have several concerns with the proposed language in 33-15-06-01.1.e. This subsection provides that Chapter 33-15-06, Emissions of Sulfur Compounds Restricted, does not apply to installations that burn pipeline quality natural gas or commercial-grade propane alone or in combination with each other.

a. Before we could approve this proposed provision, the State will need to submit a demonstration showing that installations that burn pipeline quality natural gas or commercial-grade propane could not exceed the existing SO_2 emission limits in the SIP.

b. We are assuming that you are proposing to add this provision because sources that burn pipeline quality natural gas or commercial-grade propane usually have low SO_2 emissions. However, we are concerned that if a large number of sources burning pipeline quality natural gas or commercial-grade propane are located near each other there could be a problem with meeting the NAAQS or PSD increments. Therefore, before we could approve this proposed provision, additional language should be added that indicates that the department shall impose additional requirements on installations burning pipeline quality natural gas or commercial-grade propane if it is determined that these installations may cause or contribute to exceedances of the NAAQS or PSD increments.

c. Elsewhere the State has included a definition for pipeline quality natural gas. However, a definition for commercial-grade propane has not been included. Before we could approve this proposed provision a definition for commercial-grade propane needs to be adopted. We are assuming that the department intends for commercial-grade propane to be roughly equivalent to, in terms of sulfur content and pounds of sulfur/mmbtu, pipeline quality natural gas. If that is not the case, we may have additional concerns with this proposed provision.

d. We are assuming that this proposed provision does not obviate installations from meeting other requirements under the State's regulations, e.g., permitting requirements. If this assumption is incorrect, we may have additional concerns with this proposed provision.

e. Finally, the proposed provision indicates that installations that burn pipeline quality natural gas or commercial-grade propane are not subject to the chapter. However, the chapter contains, among other things, methods of measurement and continuous emission monitoring requirements. We do not believe that installations burning pipeline quality natural gas or commercial-grade propane should be excluded from meeting such requirements, as required in those subsections.

9. The language in the opening paragraph of 33-15-06-03 should be revised to indicate that replacement or applicable alternative methods to NSPS reference methods can be used as "approved by the department and EPA."

10. Although the State is not revising 33-15-06-03.5.a. at this time, we have the following comment. This rule provides equations to determine the pollutant emission rate if Method 6 is used. We question why this equation is provided. The purpose of Method 6 is to determine SO_2 concentration from stationary sources. It is not intended to determine a pollutant emission rate. The equations provided in 33-15-06-03.5.a. are the same equations provided in Method 20 - a method to determine, among other things, SO_2 emissions from gas turbines. We do not understand why you would use a gas turbine equation for potentially any source that calculates an SO_2 concentration with Method 6.

11. If you intend to keep the equations in 33-15-06-03.5.a., then we would make the following comment. On page 6-4, the state is proposing to replace the table in 33-15-06-03.5.a(5) with F Factors from Method 19. For the most part, the Fc factors in Method 19 are lower than in the State's current table. Using method 19 Fc factors will result in lower pollutant emission rates being calculated. Since this appears to be a SIP relaxation, the State will need to demonstrate that there will be no adverse impacts to the NAAQS, PSD increments, or any other Clean Air Act requirement. As part of your demonstration, please explain why the higher F factors were used originally. Also, the equations in 33-15-06-03.5.a. indicate that a "Fc"and a "F" factor are needed to calculate a pollutant emissions rate. The F factors in Method 19 are "Fd," "Fw" and "Fc." There is no plain "F" factor. Either the equation in 33-15-06-03.5.a. will need to be revised to replace "F" with "Fd" or "Fw" or the state will need to leave its plain "F" factor found in the current table in 33-15-06-03.5.a(5).

Chapter 33-15-12, Standards of Performance for New Stationary Sources

12. The emission guidelines at 40 CFR, part 60, subpart DDDD - Emission guidelines and

compliance times for commercial and industrial solid waste incinerator (CISWI) units that commenced construction on or before November 30, 1999, require that nine items be included in the State's CISWI Plan.

1) Inventory of affected CISWI units, including those that have ceased operation but have not been dismantled.
2) Inventory of emissions from affected CISWI units in the State.
3) Compliance Schedules for each affected CISWI unit.
4) Emission limitation, operator training and qualification requirements, a waste management plan, and operating limits for affected CISWI units that are at least as protective as the emission guidelines contained in Subpart DDDD.
5) Performance testing, recordkeeping, and reporting requirements.
6) Certification that the hearing on the State plan was held, a list of witnesses and their organizational affiliation, if any, appearing at the hearing, and a brief written summary of each presentation or written summary of submission.
7) Provision for State progress reports to EPA.
8) Identification of enforceable State mechanisms that you selected for implementing the emission guidelines of Subpart DDDD.
9) Demonstration of the State's legal authority to carry out the sections 111(d) and 129 State plan.

The State's proposal to incorporate by reference (IBR) the model rule will meet the requirements of items 3, 4, and 5 listed above. In addition to the proposed rule changes to IBR the model CISWI rule, the draft CISWI Plan meets the requirements of items 1, 2, and 8 of the list above.

However, before we can consider the draft plan complete and determine its adequacy, items 6, 7, and 9 from the above list need to be included, as well as a letter from the Attorney General stating that the State will be able to carry out the specific intent of the emission guideline using the State rule as designed with the IBR as indicated in its current version of the proposed rule.

Chapter 33-15-14, Designated Air Contaminant Sources, Permit to Construct, Minor Source Permit to Operate, Title V Permit to Operate

13. Section 33-15-14-02 - Permit to Construct: Please note that we will not be acting on the changes to the State's public participation requirements, 33-14-14-02.6., that were originally submitted to EPA in 1997 (and that also appear in this version of the State's rules) until EPA finalizes revisions to the Federal minor New Source Review (NSR) public participation requirements.

14. Section 33-15-14-02.19 and 33-15-14-03.16 - Amendment of Permits: In light of the State's proposed addition of Class I significant impact levels (33-15-15-01.4.f(3)), we would like an explanation as to why this proposed revision - to change the phrase "have a significant impact" to "be a major modification" - would not be considered a relaxation of

the existing SIP. Since a "major modification" in 33-15-15-01.1.hh(3) is defined as "any emissions rate or any net emissions increase associated with a major stationary source or major modification, which would construct within ten kilometers [6.21 miles] of a class I area, *and have an impact on such area equal to or greater than one µg/m³ (twenty-four-hour average)*"[emphasis added], and since the proposed Class I significant impact levels in 33-15-15-01.4.f(3) are more inclusive than the one µg/m³ (24-hr average) specified in the definition of "major modification," we believe this may be a relaxation of the State's rules and would like clarification from the State on this point. If this change does result in a relaxation of the State's rules, we will need a demonstration from the State that these changes will not interfere with the NAAQS, PSD increments, or any other Clean Air Act requirements. **Please note our concerns with the State's proposed Class I significant impact levels, discussed under comment #18 below.**

15. Section 33-15-14-06 Title V Permit to Operate: Although these proposed revisions will not be incorporated into the SIP in their final form, we did want to note that they are acceptable. Please note one typographical error in 33-15-14-06.1.O (2)(aa). Only source categories under section 111 or 112 of the Federal Clean Air Act that were regulated as of August 7, 1980 must count fugitive emissions when determining whether the source is major (not August 1, 1980).

Chapter 33-15-15, Prevention of Significant Deterioration of Air Quality

16. In the summary of proposed changes, the State indicates that it is revising subsection 33-15-15-01.4.f.(1) to incorporate by reference 40 CFR Part 51, Appendix W, Guideline on Air Quality Models. It is not clear how the proposed change accomplishes this. We would like some clarification on the result of this change, which eliminates reference to the "Guidelines on Air Quality Models" and to the "North Dakota Guideline for Air Quality Modeling Analyses" and which eliminates the phrase "incorporated by reference" (*i.e.*, how does the State interpret this proposed version differently than what is currently approved into the SIP?).

17. In 33-15-15-01.4.f.(3), the State is proposing to add Class I significant impact levels that define ambient concentrations above which a source will be considered to "cause or contribute to air pollution in a class I area, have an impact on a class I area, or have a significant impact on a class I area.."

We have recently consulted with our Headquarters offices and it is EPA's position (as we stated in an August 30, 2001 letter to the North Dakota Department of Health) that it is not appropriate to establish Class I significance levels *when an increment violation already exists*. We believe any impact (not just one that is "significant") on a receptor in a Class I area that shows a violation of the PSD increment would be considered to contribute to that violation. Furthermore, we believe that, even if some of the impacts are relatively small they are still contributing to an existing problem.

Under current EPA policy, the PSD Class II significant impact levels are used primarily as a threshold in new source permitting to determine the scope of the modeling analysis. For Class I areas, no PSD significant impact levels have ever been codified by EPA for use in the permitting process. Given the higher level of air quality protection that Congress deemed necessary in Class I airsheds, EPA believes that it would be ill-advised to extend the use of Class I significant impact levels in determining if a source causes or contributes to air pollution in a Class I area, has an impact on a Class I area, or has a significant impact on a Class I area where violations of the increment are already occurring. In the 1980 preamble to our PSD regulations, we indicate that:

> Each proposed major construction project subject to PSD must first assess the existing air quality for each regulated air pollutant that it emits in the affected area. This analysis requirement does not apply to pollutants for which the new emissions proposed by the applicant would cause insignificant ambient impacts. Today's PSD regulations define pollutant-specific impacts that are typically considered inconsequential and that can be exempted from analysis, *unless existing air quality is poor or adverse impacts to a Class I area are in question.* [emphasis added] (45 FR 52678)

Where there is a Class I increment violation, significant deterioration has occurred, which is what the CAA intended the PSD program to prevent. The use of significant impact levels would enable new sources to avoid doing a cumulative impact analysis to determine the source's potential impact on the increment levels. EPA believes this should not be allowed, until a state submits a SIP revision to correct any increment violations.

Furthermore, we believe adding these Class I significant impact levels is a relaxation of the existing SIP, interferes with Clean Air Act requirements and is inconsistent with section 110(l) of the Clean Air Act. Unless the State adds a provision to ensure that the proposed Class I significant impact levels would not be used where violations of the increment are already occurring, we believe we would likely not approve such a revision.

Desert Rock Energy Co., PSD Appeal 08-03
Conservation Petitioners' Exhibits

EXHIBIT 44


San Juan Pow
San Juan River
Morgan Lake
Four Corners Power Plant
Navajo Nation

EXECUTIVE SUMMARY

This environmental impact statement (EIS) is being prepared in compliance with the National Environmental Policy Act (NEPA) to analyze and disclose environmental effects that could occur with implementation of the proposed Desert Rock Energy Project (also referred to as the proposed project). The three project proponents— Diné Power Authority (DPA), Desert Rock Energy Company LLC (an affiliate of Sithe Global Power LLC), and BHP Navajo Coal Company (BNCC)—are proposing the following:

- DPA and Desert Rock Energy Company LLC jointly propose to develop, construct, and operate a coal-fired electrical power plant with a capacity to generate up to 1,500 megawatts (MW) of power. Supporting facilities would include a well field that would draw 4,500 acre-feet per year (af/yr) from the Morrison Aquifer for project-related purposes and an additional 450 af/yr for local municipal use, a water-supply pipeline from the well field to the power plant, 500 kilovolt (kV) transmission lines, other upgrades and ancillary facilities required for the production and transmission of electricity, and new access roads.
- BNCC proposes to expand existing surface-coal-mining operations at the Navajo Mine, which is located within the existing BNCC lease area (see Figure ES-1), to provide fuel for the power plant. Under this proposal, mining operations and related facilities would extend into coal resource Areas IV North, VI South, and V within the lease area. These operations would require construction of additional facilities. All mined areas would be reclaimed as mining operations are completed.

The proposed project would be located entirely within the Navajo Indian Reservation approximately 30 miles southwest of Farmington in San Juan County, New Mexico (Figure ES-1). The power plant would occupy about 150 acres of a 592-acre parcel of land immediately adjacent to and west of the BNCC lease area. This parcel would be leased from the Navajo Nation. The coal fuel supply would be mined from Areas IV South and V (approximately 17,500 acres) and transported by conveyor system to a coal preparation facility that would be located in Area IV North of the BNCC lease area, near the power plant.

The purpose and need of the proposed project is to:

- Support the Navajo Nation's objective for economic development by providing long-term employment opportunities and revenue cash-flow streams from the development of Navajo natural resources.
- Use Navajo Nation coal to generate electricity.
- Help meet demand for up to 1,500 MW of electrical power in the rapidly growing southwestern United States.
- Provide fuel diversity and a more economically stable and predictable power supply for utilities in the Southwest.

The proposed project requires a long-term (50 year) lease between the Navajo Nation and DPA, and a corresponding sublease between DPA and Desert Rock Energy Company LLC. Because the project would be located within the Navajo Indian Reservation (land held in trust by the Federal Government for the Navajo Nation), the lease would require approval by the U.S. Department of Interior's Bureau of Indian Affairs (BIA), the lead Federal agency responsible for the preparation of this EIS. BIA has determined that approval of the lease and other aspects of the proposed project would be a major Federal action and thus requires the preparation of an EIS. Other Federal agencies and the Navajo Nation are cooperating with BIA in preparation of this EIS: the Bureau of Land Management (BLM), Office of Surface Mining Reclamation and Enforcement (OSM), U.S. Environmental Protection Agency Region IX (USEPA), and U.S. Army Corps of Engineers (USACE). This EIS is intended to satisfy NEPA requirements vis-à-vis each agency's decision-making responsibilities related to the siting, construction, operation, and maintenance of the proposed project and to aid other Federal, Navajo Nation, State, and local permitting authorities with their permitting responsibilities regarding surface coal mining, CCB disposal, and reclamation activities that would take place on the BNCC lease area under the Surface Mining Control and Reclamation Act of 1977 (SMCRA).

PROPOSED PROJECT AND ALTERNATIVES

Three alternatives are evaluated in detail in this Draft EIS:

- Alternative A is the no action alternative—no project would be built.
- Alternative B is the action proposed by DPA, Desert Rock Energy Company LLC, and BNCC—construction and operation of a 1,500 MW power plant and associated facilities and expansion of Navajo Mine operations to support the plant.
- Alternative C is an alternative to the proposed action—construction and operation of a 550 MW power plant and associated facilities and expansion of Navajo Mine mining operations to support the plant.

A number of alternative locations, technologies, and fuel sources were evaluated and eliminated before detailed analysis. These alternatives and the reasons they were eliminated are described in Section 2.4 in Chapter 2.

The three alternatives evaluated in detail in the EIS are briefly described below. Additional detail is provided in Section 2.2 in Chapter 2.

<u>Alternative A – No Action</u>

Council of Environmental Quality regulations implementing NEPA require that an agency consider no action as one alternative to a proposed action (Title 40, Code of Federal Regulations, Section 1502.13(d) [40 CFR 1502.13(d)]). Under the No Action Alternative considered here, approvals for the long-term lease, rights-of-way, mining permits, and other permits needed for the proposed power plant and associated facilities would not be granted. Without these approvals and permits, the project would not be implemented.

For analysis purposes, the effects of taking no action serve as the baseline of environmental information against which impacts from the proposed project would be predicted to occur if the necessary agency actions are taken.

<u>Alternative B – Proposed Action</u>

Under Alternative B, the facilities and activities that would be associated with the proposed action alternative include (1) the power plant and associated infrastructure, (2) construction activities, (3) operation and maintenance activities for the proposed power plant, (4) mining operations in the BNCC lease area, and (5) decommissioning activities.

The proposed facilities would include up to two 750 MW generation units and a plant-cooling system, coal-handling and processing facilities, power transmission lines and interconnection facilities, a water-supply system, an access road to the plant site, waste-management operation facilities, and other ancillary facilities associated with the generation and transmission of electricity. Table ES-1 summarizes the acreage requirements for each major facility for each action alternative.

Table ES-1 Acreage Requirements for Proposed Facilities and Infrastructure under Alternatives B and C

Facility	Acres	
	Alternative B	**Alternative C**
Power Plant		
Leased site	592	592
Footprint	149	110
Coal Preparation Facilities on BNCC Lease Area	101	101
Infrastructure		
Proposed Transmission Line (Segments A, C, D)	1,205	766
Alternative Transmission Line (Segments B, C, D)	1,373	829
Proposed Water Well Field B	890	792
Alternative Water Well Field A (includes utility corridor)	1,040	942
Main Power Plant Access Road	21	21

Power Plant. The power plant would be a supercritical pulverized-coal type facility. Use of a single reheat, supercritical steam cycle and other design features would enable this plant to operate with higher net efficiency than existing coal-fired power plants in the region.

The power plant would be constructed within a 592-acre leased area east of the Chaco River and north of the Pinabete Wash. The footprint of the plant and associated facilities would occupy about 149 acres within that area (see Figure ES-1). Air pollutants would be reduced through use of the emission controls described in Chapter 2.

Access Road. The proposed access road would access the power plant site from BIA 5082 (Burnham Road) and run west across the BNCC lease area along the boundary between Areas IV North and IV South. This alignment would interconnect with BNCC's proposed Burnham Road Realignment Project as shown on Figure ES-1.

Transmission Line. Two single-circuit 500 kV transmission lines, each within a 250-foot-wide right-of-way, would leave the power plant site and parallel the east side of the Chaco River (Segments A and C on Figure ES-1) in a northerly direction for approximately 14.9 miles to Arizona Public Service's Four Corners Generating Station. From the generating station, one single-circuit 500kV transmission line would parallel an existing 230kV transmission line within a 250-foot-wide right-of-way, across the San Juan River, to interconnect with the proposed Navajo Transmission Project transmission line, a distance of approximately 10.8 miles (Segment D on Figure ES-1). The proposed typical structure for the transmission line would be a self-supporting, four-legged, steel-lattice structure approximately 135 feet in height with a nominal spacing of 1,200 to 1,600 feet between structures.

An alternative transmission line corridor evaluated in this EIS would be composed of Segments B, C, and D (Figure ES-1), which would be longer than the proposed alignment by nearly 3 miles. The primary difference between the two corridors is that Segment B would parallel the Chaco River on the west side, and Segment A on the east side. In addition, Segment B would be collocated with existing transmission lines for about 8.8 miles of its length.

Water-Supply System. The average annual water consumption demand for Alternative B is estimated to be 4,500 af/yr, or 2,795 gallons per minute (gpm) on average, of continuous flow for a period of 50 consecutive years. Water re-use would be optimized for a zero-liquid discharge. An additional 450 af/yr would be made available to meet Navajo municipal demand. Based on evaluation of the hydrogeologic characteristics of the Morrison aquifer in the study area and the results of the well impact analysis, it was estimated that 10 to 20 new production wells would meet this demand (URS Corporation 2005). Ground water from nearby deep wells that access the Morrison aquifer would be the primary water supply.

The proposed well field area would occupy 890 acres within the power plant site lease area and along the proposed transmission line Segment A if adequate space is not available for all of the project wellheads within the lease area (see Proposed Well Field Area B on Figure ES-1). The 10 to 20 wells generally would be placed equally apart at a minimum of 0.25-mile spacing, as practicable based on surface characteristics and hydrology. Each well would be networked to the water-transmission pipeline mains, which would deliver the water to the onsite 2.5-million-gallon water storage tank. Each well would be equipped with a submersible pump powered by an electric motor. The final size of the pumps and motors would not be determined until after test wells were drilled and properly developed. The wells would be controlled via telemetry by the water level in the storage tank. The telemetry system would likely be connected by fiber optic cable buried in the pipeline trench.

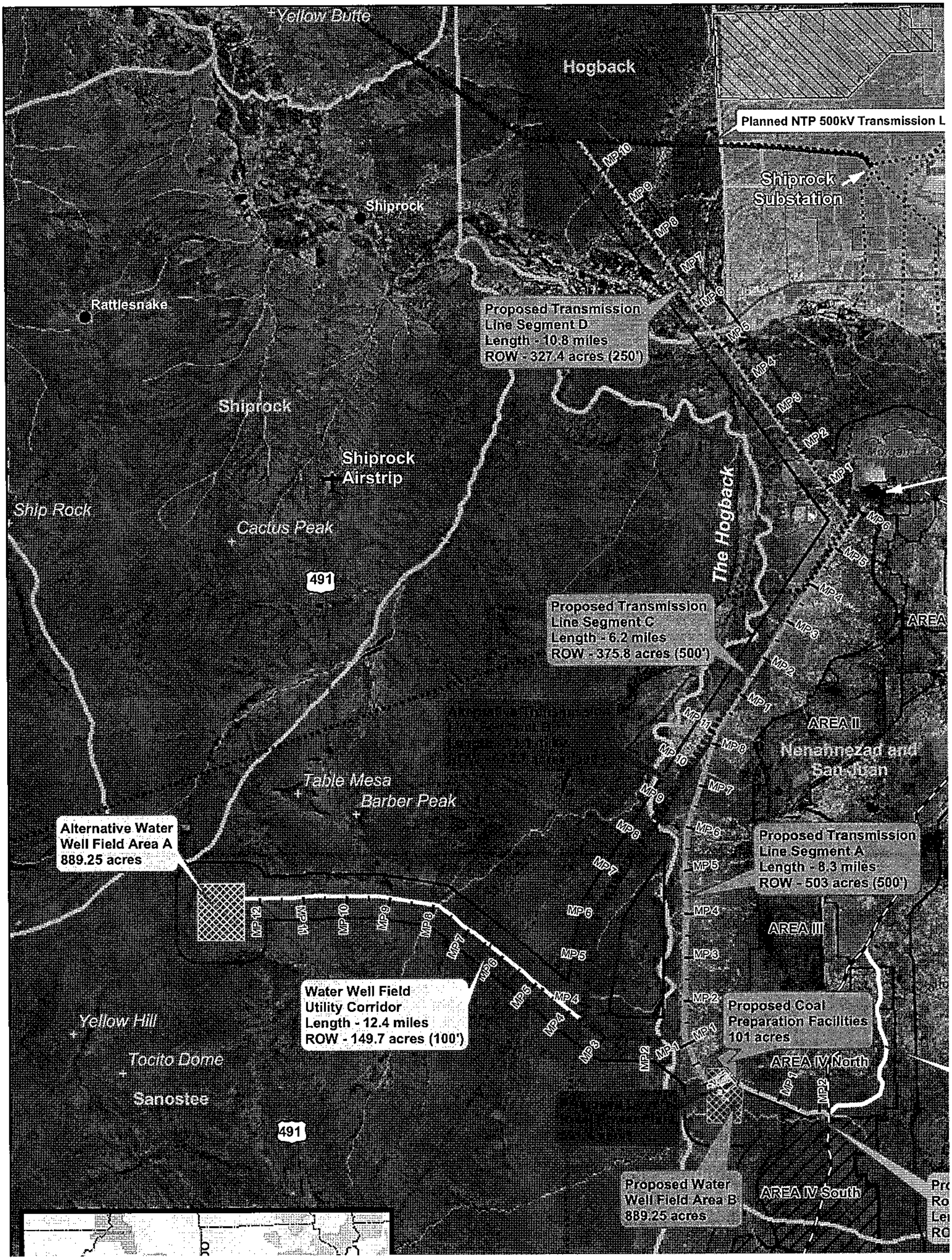
An alternative well field location also is evaluated in this EIS. Alternative Well Field Area A would be located west of Highway 491 and south of Table Mesa, on nearly 890 acres about 12.4 miles northwest of the proposed plant site (see Well Field Area A on Figure ES-1). A 100-foot-wide utility corridor would be required to supply electricity to the wells.

For either well field alternative, a system of collector and water-transmission pipelines would be constructed to deliver water to the plant site. Appurtenant facilities would include isolation valves, control valves, access manways, air release/vacuum valves and vaults, blow-off valves, fiber-optic splice vaults, cathodic-protection facilities where necessary, and pipeline-alignment markers.

Overhead or underground power lines would be constructed to supply electricity to the wells. The power lines would be constructed in the same right-of-way and paralleling the pipelines, with appropriate spacing between the utilities as needed to ensure safety. The length of each power line would be determined upon completion of design and engineering studies. Control of the well pumps would be from the power plant control room via telemeterized digital control system.

If production wells are located outside the plant boundary, road access to the wells would be needed for construction, operation, and maintenance. Unpaved access roads would be approximately 15 feet wide and constructed in accordance with BIA and/or Navajo Nation road standards.

Mining Operations in the BNCC Lease Area. A new surface mine (the proposed Navajo Mine Extension Project) would be developed to provide coal to the power plant. The mine would be located in areas IV South and V within the existing BNCC lease area, which are adjacent to the proposed power plant site (see Figure ES-1). At full production, 6.2 million tons of coal would be mined per year for the proposed project. The mine would have a life of 50 years.


Yellow Butte
Hogback
Planned NTP 500kV Transmission L
Shiprock Substation
Shiprock
Rattlesnake
Proposed Transmission Line Segment D Length - 10.8 miles ROW - 327.4 acres (250')
Shiprock
Shiprock Airstrip
Ship Rock
Cactus Peak
491
The Hogback
Proposed Transmission Line Segment C Length - 6.2 miles ROW - 375.8 acres (500')
AREA I
AREA II
Nenahnezad and San Juan
Table Mesa
Barber Peak
Alternative Water Well Field Area A 889.25 acres
Proposed Transmission Line Segment A Length - 8.3 miles ROW - 503 acres (500')
AREA III
Water Well Field Utility Corridor Length - 12.4 miles ROW - 149.7 acres (100')
Proposed Coal Preparation Facilities 101 acres
AREA IV North
Yellow Hill
Tocito Dome
Sanostee
491
Proposed Water Well Field Area B 889.25 acres
AREA IV South
MP 1
MP 2
MP 3
MP 4
MP 5
MP 6
MP 7
MP 8
MP 9
MP 10
MP 11
MP 12

Alternative C – 550 MW Subcritical Facility

The purpose of this alternative is to provide a basis for comparing and considering the potential impacts of the proposed action. Alternative C is modeled after the Cottonwood Energy Project, which was proposed by BNCC in 2002 for the same site as that proposed for the 1,500 MW project under Alternative B. Relative to Alternative B, power generation under this alternative would be less efficient and there would be greater emissions and water usage per unit of power produced, but overall emissions and water consumption would be lower because of the reduced size of the unit. Coal usage under Alternative C would be 10 to 15 percent higher per megawatt-hour because of the higher heat rate of the subcritical plant.

The project location would remain the same under this alternative. Facilities would include one 550 MW generation unit, a plant-cooling system, coal handling facilities, power transmission interconnection facilities, a water-supply system, an access road to the plant site, and waste-management operation facilities.

Power Plant. The smaller, 550 MW power plant would also be constructed within the 592-acre lease area east of the Chaco River and north of the Pinabete Wash. The footprint of the plant and associated facilities would occupy about 110 acres within that area (39 acres fewer than Alternative B). Air pollutants would be reduced through emission controls (see Chapter 2).

Access Road. The access road to the power plant under Alternative C would be the same as that under Alternative B.

Transmission Line. The transmission line alternatives for Alternative C would follow the same corridors as in Alternative B. However, the right-of-way requirements would be reduced because one single-circuit transmission line would be constructed. The proposed transmission line would require about 766 acres under Alternative C, a reduction of about 439 acres from Alternative B. The alternative transmission line corridor would require 829 acres under Alternative C, or 544 acres fewer than Alternative B.

The proposed typical structure for the transmission line would be a self-supporting, four-legged, steel-lattice structure approximately 135 feet in height with a nominal spacing of 1,200 to 1,600 feet between structures. These characteristics would be the same as the proposed project under Alternative B.

Water-Supply System. The anticipated needs for water would be 4,000 af/yr, which would be a reduction in water usage of about 12 percent compared to Alternative B. An additional 450 acre-feet would be provided for Navajo municipal use annually, assuming the same water agreement would apply for both Alternatives B and C. The proposed water source would be groundwater from the Morrison aquifer, similar to Alternative B. Based on evaluations of the hydrogeologic characteristics of the Morrison aquifer, it was estimated that 9 to 18 new production wells would meet this anticipated water demand. The alternative locations for the well field would be the same as evaluated under Alternative B; however, the well field itself would be about 11 percent smaller.

Each well would be networked to the water-transmission pipeline mains that would deliver the water to the onsite 1.5-million gallon water-storage tank. Each well would be equipped with a submersible pump powered by an electric motor. The wells would be controlled via telemetry by the water level in the regulating/storage reservoir. The collector pipelines would be connected to manifolds on the water-transmission pipeline mains that would deliver the groundwater to the water-storage tank at the power plant site.

Mining Operations in the BNCC Lease Area. A new surface mine (the Navajo Mine Extension Project) would be developed within Area IV South of the BNCC lease area to provide coal to the power plant. Under Alternative C, Lease Area V would not be required to supply adequate coal. At full production, 2.4 million tons of coal would be mined per year to support the power plant operations. The mine would have a life of 50 years.

AFFECTED ENVIRONMENT

Chapter 3 describes the existing conditions of the human and natural environments that could potentially be affected by the action alternatives. The descriptions of existing conditions are based on the most recent data available in professional literature, published and unpublished reports, and agency databases. Field reconnaissance and interviews were conducted as necessary to verify specific information (such as biological resources, land use, and traditional and cultural resources). The environmental resources described include air, water, geology, soils, wetlands, vegetation, fish and wildlife, cultural, visual, noise, land use, and socioeconomics.

ENVIRONMENTAL CONSEQUENCES

The potential environmental consequences of each alternative were determined using the description of the existing conditions of the environment provided in Chapter 3 as a baseline to identify and measure potential impacts. Best management practices, conservation measures, and the effectiveness of mitigation measures were considered in assessing the impacts on each resource. The full discussion of the impact assessment is provided in Chapter 4.

The cumulative effects of the project were considered as part of the analysis (see Chapter 5). Cumulative effects result from the proposed action's incremental impacts when these impacts are added to the impacts of other past, present, and reasonably foreseeable future actions, regardless of the agency or person who undertakes them (Federal or non-Federal).

The impact of most consequence under Alternative A would be the non-realization of project-related economic development (though it is possible that BNCC's Lease Areas IV South and V could be developed to support a different project in the future, for purposes of analysis, is was assumed that the area would remain undeveloped). Under this scenario, there would be no gain in project-generated direct wage income, induced income, and tax and royalty payments to the Navajo Nation (an estimate of $43 million under Alternative B, and $18 million under Alternative C). This impact would have great resonance in a disproportionately low-income Navajo community characterized by high unemployment and lack of economic opportunity. Because the project would not be built under this alternative, most environmental resources would remain unchanged.

The environmental consequences under Alternatives B and C—the action alternatives—would include effects on the natural environment as well as socioeconomic effects. The differences between the two action alternatives would be primarily differences in scale: the types of impacts would be the same. The components of the project would be in the same general locations, but the smaller 550-MW facility under Alternative C would result in an overall smaller footprint for the power plant and associated facilities. With the smaller unit, fewer acres would be disturbed and less water and coal would be required, but the smaller plant would use resources less efficiently: it would burn more coal and emit more air pollutants per kilowatt generated. In addition, the economic impact of the two plants would vary. Key differences in impacts between Alternatives B and C are described below, presented by the resource area that would be affected. Table ES-2 summarizes and compares the key impacts that would result from Alternatives A, B, and C.

The key socioeconomic impacts under the action alternatives would be related to the economic benefits associated with each project. It is estimated that many of the workforce would originate from the local area, where qualified workers reside and employment is needed. Alternative B would provide more jobs relative to Alternative C (about 420 permanent jobs versus 255 permanent jobs, plus construction employment for both alternatives). Tax and royalty payments to the Navajo Nation would also be greater under Alternative B (estimated at $43 million, compared to $18 million under Alternative C).

Air quality would be affected under both action alternatives as the result of power plant emissions, vehicle emissions, and emission of pollutants from earthmoving activity during construction. Mining and coal-handling operation would also generate fugitive dust. However, mitigation measures would reduce fugitive dust, particularly during construction, and the Federal National Ambient Air Quality Standards (NAAQS) would not be exceeded under either alternative. The smaller facility under Alternative C would emit about 39 percent of the pollutants relative to the facility proposed under Alternative B. However, the project proponents have committed to voluntarily employing mitigation measures that were developed with the National Park Service and U.S. Forest Service. These measures provide for the project proponents to invest in third-party capital improvements that would reduce sulfur dioxide (SO_2) in the region. The actions stipulated in the mitigation agreement would reduce SO_2 in the region by 110 percent of the proposed project emissions, and also include a commitment to controlling mercury emissions. Several trends influence the potential for project-related cumulative impacts on regional air quality, notably the increase in energy development projects and overall reductions of SO_2 from existing sources in the region. Modeling of cumulative air quality in the region indicates that the proposed project would not result in additive degradation to existing air quality because of SO_2 reductions on other projects.

The risk to human health under both action alternatives was analyzed, primarily as it is related to air emissions. As mentioned, the health-protective NAAQS criteria would not be exceeded under either alternative, and risks associated with residential exposure to air toxics would be below target health goals. The cumulative cancer risk is greater than USEPA's acceptable risk range; however, nearly all of that risk is due to existing concentrations of arsenic in soil and native vegetation and the contribution of arsenic from the operation of the proposed facility would be slight. Arsenic is naturally occurring in soil and background concentrations of arsenic commonly result in health risks in excess of USEPA's target health goals because of the toxicity of the chemical.

Potential impacts on both surface and ground water resources were assessed. General construction of the power plant site and associated facilities could indirectly affect surface water resources by increased stormwater runoff from the site carrying sediment and contamination loads into surface water and by contamination from construction equipment and activities infiltrating area surface waters. These impacts would be mitigated by measures including stormwater-runoff control, revegetation, and erosion control measures. Surface waters in the proposed project area could be impacted by filling, bridging, or the installation of culverts during construction activities. Commitments to reduce impacts on Waters of the U.S. would be made through the USACE permitting process in accordance with the Clean Water Act.

As part of both action alternatives, a well field would provide groundwater for use by the project - 4,500 af/yr (plus 450 af/yr for Navajo municipal uses) for Alternative B and 4,000 af/yr (plus 450 af/y for Navajo municipal uses) for Alternative C. A groundwater predictive computer model was constructed to evaluate the impacts on groundwater drawdown that would be associated with various combinations of well locations. It was concluded that the 10-foot drawdown contour line would reach one well registered by the New Mexico State Engineer's Office, but this level of drawdown would not constitute a significant adverse impact. The project proponents would continue to refine and calibrate the ground water model following construction, installation, testing, and logging of test and monitoring wells.

Initial studies to analyze samples from artesian well locations in Burnham and Sanostee Chapters were conducted to evaluate the potential for a relationship between those water sources and the Morrison aquifer. The Burnham Chapter artesian wells and the Morrison Aquifer analysis showed the two water sources have dissimilar geochemical "footprints" (MBE 2007a). The geochemical comparisons of samples from the Sanostee Chapter do not conclusively indicate a similarity or dissimilarity with respect to the geochemical "footprints" of either water source (MBE 2007b). Further sampling from test wells at the proposed water well field B will assist in determining classification of the water supply and any geochemical footprint between the Morrison Aquifer and seeps and springs, as well as provide more information on the depth and quality of groundwater.

Concern has been voiced by stakeholders about the disposal of coal combustion byproducts (CCBs) such as fly ash. A 2006 study by the National Academy of Sciences (NRC 2006) identified potential impacts on water quality from CCBs. The study suggested that, while there were no cases where water quality exceedences were directly attributable to the burial of CCBs, concern about proper management was warranted. Characterization of a mine CCB disposal site and of the materials placed in it was essential and the report recommended that characterization methods, including leach tests that are currently used by OSM permittees on the Navajo Nation, were the correct approach. The report suggested that SMCRA be amended to disseminate these methods throughout the industry. Reclamation plans need to specify how CCBs would be used and what sorts of covers are placed to prevent root invasion and uptake of trace elements. The report also suggested that monitoring plans be designed to target potential releases from CCB disposal areas, and establish performance standards. The current Navajo Mine SMCRA permit stipulates all of these conditions and has been approved by OSM and the Navajo Nation. It is expected that these stipulations would also exist in the permit for BNCC Lease Areas IV South and V.

The primary impacts on biological resources under both action alternatives would be associated with surface disturbance: vegetation removal and associated habitat loss or fragmentation, and changes to wildlife movement or corridors as a result of increased human activity. The types of impacts would be the same under both alternatives, but surface disturbance would be less under Alternative C due to the smaller footprint for facilities. Surface disturbance could also cause soil erosion and affect productivity, but mitigation measures and best management practices would be employed to reduce effects on soils. The biggest difference in surface disturbance between the two action alternatives is that coal would not be extracted from Lease Area V under Alternative C, and thus no mining operations would occur in that area as a result of the project. Impacts on biological resources would be mitigated through reclamation of temporary right-of-way and control of noxious and invasive weeds. Under both alternatives, impacts on federally listed or sensitive species would be localized and not likely to result in a loss of species viability nor cause a trend towards federal listing. Mitigation measures to protect the Mesa Verde cactus and avoid impacts on other species that may inhabit the area have been identified, including biological monitoring.

Both alternatives would cause small increases in mercury and selenium deposits that could reach the San Juan River or Morgan Lake; however, the change in water quality under both alternatives would be nominal relative to established standards. Mercury and selenium are bioaccumulative, meaning it accumulates in the tissues of aquatic wildlife. Unlike mercury, concentrations of selenium do not increase significantly (biomagnify) in animals at each level of the food chain going from prey to predator. Potential adverse impacts to area aquatic resources from incremental increases in mercury and selenium concentrations would be minor and long term. These impacts are not likely to result in a loss of species viability range-wide, nor cause a trend to Federal listing. The subsequent minor change in water quality may affect, is likely to adversely affect federally listed aquatic species (Colorado Pikeminnow and razorback sucker).

Impacts on land uses along the transmission lines could be avoided under both action alternatives by adjusting the tower locations to avoid sensitive land uses. Leased homesites on the mining lease areas would be displaced; Alternative B would displace 14 such homesites and Alternative C would displace 8. Holders of impacted homesites, grazing permits, and customary-use areas would be compensated for the value of disrupted livestock production and relocation or replacement of improvements to their grazing area or homesite in accordance with 13 Navajo Tribal Code Section 1401-1403, which requires compensation for all surface use.

The project would impact visual resources in the project area under both action alternatives. Residential viewers who would be able to view the facilities would be most affected by these changes. Although the stack height would be higher under Alternative B, the primary impact of the introduction of a new industrial facility in this location would be essentially the same for the two action alternatives.

Cultural resources in the project area would potentially be affected under both action alternatives. The residual effects (after mitigation) would be the same under both action alternatives. Mitigation would include sensitive placement of transmission towers to avoid cultural sites, and adherence to the measures outlined in the project-specific programmatic agreement regarding the treatment of cultural properties. In addition, potential adverse impacts on traditional cultural properties and Navajo burials would be addressed in accordance with the Navajo Nation's Policy for the Protection of *Jishchaa'*: Gravesites, Remains, and Funerary Items.

Environmental justice is a concern under all three alternatives due to the disproportionately minority and low-income population in the project area. Any deterioration of environmental quality would be disproportionately borne by this population. A key issue raised during scoping was air quality and associated effects on human health. The emissions of air pollutants would increase under both of the action alternatives; however, modeling indicates that the cumulative impacts would be below health-protective Federal standards. The cumulative impacts analysis identifies that this region is home to two other coal-fired power plants as well as other energy and mining projects. Thus, the local population is disproportionately impacted by the cumulative land use and visual effects of these facilities, which generate power for a much larger area.

Under both action alternatives, alternative locations for the transmission lines and the well field are also evaluated. Table ES-3 highlights the key distinctions in the infrastructure alternatives.

The primary difference between the two transmission line routes would be the use of Segment A versus Segment B (refer to Figure ES-1). Segment B would result in more surface disturbance than Segment A because of the longer route. This would translate to somewhat more stress on vegetation and habitat and fugitive dust from earthmoving activity during construction. Two residences would be within the right-of-way for Segment B, but fewer cultural sites are present. Potential impacts on cultural resources would be avoided through sensitive tower placement or mitigated in accordance with the programmatic agreement or the Navajo Nation's policy for the Protection of *Jishchaa'*.

The proposed well field area B would be co-located with the power plant lease area and a portion of the proposed transmission line. The alternative well field A would be located west of the power plant site and would require construction of a water pipeline to link the two facilities. Well field alternative A would require more surface disturbance than the alternative B well field, since a water pipeline would be required. Mesa Verde cactus populations were identified along the water pipeline corridor, increasing the possibility of impacts on this sensitive plant.

Table ES-2 Summary of Impact Assessment

Resource	No-Action – Alternative A	Proposed Action – Alternative B 1,500 MW Facility	550 MW
Air Quality	Alternative A would not result in an increase in air emissions. Existing sources of criteria pollutants in the air toxics in the region would continue to operate. Ambient concentrations meet Federal standards for air quality.	Air pollutant emissions would result from earthmoving activity during construction (fugitive dust, PM_{10} and $PM_{2.5}$), tailpipe emissions from vehicles (PM, NO_x, SO_2, CO, and VOC), and coal combustion by the power plant (CO, NO_x, SO_2, and others). Mining operations and coal handling operations also would generate PM_{10} emissions. Alternative B would comply with Federal air quality standards. Particulate emissions during construction would be temporary and mitigated through adherence to the recommended mitigation measures. The project proponents have committed to mitigation measures to invest in third-party capital improvements projects to further reduce SO_2 in the region. The actions stipulated in the mitigation agreement would reduce SO_2 in the region by 110 percent of the proposed project emissions, and also include a commitment to controlling mercury emissions.	Air pollutant em same sources as Pollutant emissi would generally Alternatives B a PM_{10} would be g because of its sh (see Table 4-7). would result fro Alternative C (se emissions per un occur. Alternative C w quality standard Particulate emis would be tempo adherence to the measures.
Water Resources	Existing activities at the site, primarily cattle grazing and rural domestic consumption, would cause minimal to no impact upon the existing groundwater system. Runoff from the agricultural and grazing lands can carry sediments, and possibly nutrients and other pollutants, to surface waters where they could potentially degrade water quality.	Stormwater runoff from construction activities and mining operations would be controlled by mitigation measures. Commitments to reduce impacts on Waters of the U.S. (about 1.46 acres total for the permitted plant and associated facilities) would be made through the USACE permitting process in accordance with the Clean Water Act. Drawdown due to groundwater pumping was modeled, and no substantial impacts to	Same impacts as would be fewer waters due to the plant and lack of V.

Resource	No-Action – Alternative A	Proposed Action – Alternative B 1,500 MW Facility	[cut off] 550 MW
		existing wells are anticipated. Groundwater modeling will continue to be refined and calibrated following construction, installation, testing, and logging of test and monitoring wells.	
Biotic Resources	Alternative A would not result in loss or change to vegetation or habitat.	Alternative B would result in the removal of vegetation for the life of the project (a maximum of about 16,996 acres) and changes in the density or diversity of vegetation in areas that are reclaimed. Impacts on wildlife would include noise, habitat loss and fragmentation, changes to wildlife corridors or movements, increased mortality from vehicle traffic, and increased fugitive dust and sedimentation. Impacts on federally listed or sensitive species would be localized and not likely to result in a loss of species viability nor cause a trend to federal listing. Small increases in mercury and selenium levels may occur in the San Juan River and Morgan Lake; this would be expected to produce a minor, long term impact because of bioaccumulation of these substances.	Same impacts or Alternative B, al impacted (a max Impacts on feder species would be in that impacts o species would be result in a loss o trend to federal l between the alte narrower right-o line would slight migratory stopo nesting habitat f flycatcher, and (Lease Area V w effects on habita
Land Use	Alternative A would not result in changes to land use.	Negligible impacts on land use and recreation would result from the construction and operation of the power plant. One residence would be within the right-of-way for Segment D of the proposed transmission line, and a planned burial area would be crossed by Segment C. These uses would be avoided by adjusting the locations of the lattice towers to the extent practicable. Leased homesites (9 residences and 5 hogans) would be displaced as a result of the mining	Same as Alterna residences woul mining operatio mined under this

Resource	No-Action – Alternative A	Proposed Action – Alternative B 1,500 MW Facility	... 550 MW
		operations in Lease Areas IV and V. BNCC would reach agreement with holders of homesite leases or grazing permits to compensate them, in accordance with 13 Navajo Tribal Code Section 1401-1403.	
Topography, Soils, and Geology	Alternative A would result in no effects on topography, soils, geology, or mineral resources at the proposed project site.	The implementation of the proposed project would result in surface disturbance that would alter the topography, increase soil erosion, and reduce soil productivity. These impacts would be mitigated through best management practices, such as design controls, and reclamation plans.	Impacts would b although fewer a
Agriculture	Alternative A would not change current conditions for agriculture and grazing.	Negligible to minor impacts on grazing would occur because of the small acreage that would be affected, relative to the larger use area. Best management practices would reduce impacts on soils and vegetation associated with surface disturbance. Existing agricultural fields would be crossed by the proposed transmission line, but impacts would be avoided or mitigated by paralleling existing lines and sensitive tower placement.	Same as Alterna
Visual Resources	Alternative A would not result in changes to visual resources.	Impacts on visual resources would occur as a result of the introduction of an industrial facility on an undeveloped landscape and the removal of vegetation.	Impacts would b but would affect because of the sl mining would oc
Socioeconomics	Under Alternative A, the employment and tax revenue would not be generated. High unemployment and poverty levels on the Navajo Indian Reservation would not be alleviated under Alternative A.	The proposed project would generate direct and indirect employment, induced income as those wages circulate throughout the economy, and tax and royalty revenue. The proposed project would be expected to provide 420 permanent jobs plus construction employment, and tax and royalty payments to the Navajo Nation totaling $43 million annually.	Alternative C als employment and it would be redu scale of the proje expected to prov construction emj payments to the million annually

Resource	No-Action – Alternative A	Proposed Action – Alternative B 1,500 MW Facility	550 MW
Cultural Resources	No cultural resources would be affected by the construction or operation of the projects.	Impacts on cultural resources would be expected to be minimal after mitigation, which would include adherence to measures outlined in the programmatic agreement to avoid or reduce those impacts. Potential adverse impacts on traditional cultural properties and Navajo burials would be addressed through consultation with the Navajo Nation Historic Preservation Department and through compliance with the Navajo Nation's Policy for the Protection of *Jishchaa'*: Gravesites, Human Remains, and Funerary Items.	Impacts would b after mitigation.
Paleontological Resources	No paleontological resources would be affected by the construction or operation of the projects.	The areas where project facilities would be constructed may contain fossils. Any potential impacts would be mitigated through on-the-ground surveys and monitoring during construction, and training construction personnel to recognize possible paleontological resources.	Impacts would b after mitigation.
Traffic and Transportation	Alternative A would not change current conditions if traffic and transportation.	Traffic would be generated by travel of equipment and employees to the proposed project site, most notably during construction. The increase over existing conditions would not adversely impact the existing transportation network. Improvements would be provided on N36, N3005, N5 and Burnham Road.	Impacts would g Alternative B, al would be lower.
Noise	Alternative A would not change existing noise levels.	During construction, predicted noise levels from the proposed project would not exceed the 90 dBA hourly sound level limit set by the Federal Transit Administration. During operation, it would not exceed the 55dBA Ldn limit set by the USEPA at sensitive receptors.	Same as Alterna

Resource	No-Action – Alternative A	Proposed Action – Alternative B 1,500 MW Facility	/ 550 MW
Human Health	Existing sources of criteria pollutants in the air toxics in the region would continue to operate. Because ambient concentrations meet Federal standards for air quality, current conditions would be expected to cause minimal to no adverse health effects.	Air emissions would not exceed the health-protective NAAQS criteria. Risks and hazards for residential exposures to air toxics emitted through both direct pathways (inhalation) and indirect pathways (contacts with soil and ingestion of wheat, native plants, or beef) of exposure would be below target health goals.	Same as Alterna
Environmental Justice	The economic developments associated with each of the projects would be foregone under Alternative A. Wages, employment, and related economic and social benefits to the local population would not occur under Alternative A. Taxes and other revenues that would be distributed to all Navajos would not occur under Alternative A. The local population that would have been the recipients of wages and other economic benefits is over 95 percent Navajo and 40 percent of Navajo households live below the poverty line.	The proposed project would comply with Navajo Employment Preference requirements. Any deterioration in air quality would be disproportionately experienced by the local population, which meets the criteria for environmental justice considerations. However, proposed project emissions would meet all NAAQS. Economic and social benefits would affect local and nationwide populations. Local populations would benefit directly from jobs, wages, and improved infrastructure; the general population of the Navajo Indian Reservation would benefit through distribution of taxes and other revenues.	Impacts would b although the eco environmental ju reduced by at lea

Table ES-3 Summary of Impact Assessment for Alternative Infrastructure Locations

Resource	Transmission Line		Water-Supply	
	Proposed Transmission Line Segments A, C, and D	**Alternative Transmission Line Segments B, C, D**	**Proposed Well Field Area B**	
Air Quality	About 145.7 (Alternative B) or 92.7 tons (Alternative C) of PM_{10} would be generated due to earthmoving during construction.	An additional 17.1 (Alternative B) or 10.8 tons (Alternative C) per year of PM_{10} would be generated due to earthmoving during construction.	About 82.7 (Alternative B) or 73.8 tons (Alternative C) of PM_{10} would be generated due to earthmoving during construction.	Abc 137 PM eart
Water Resources	For Segment A, permanent impacts to Waters of the U.S. would total 0.02 acre (1066.80 square feet), and no direct impacts on Waters of the U.S. would be associated with Segments C and D. During construction, the potential for an impact on surface or groundwater from accidental hazardous fluid spills would be reduced through hazardous fluid spill prevention and protection practices.	Same as the proposed transmission line, except that impacts to Waters of the U.S. from Segment B would total 0 acres.	Impacts to Waters of the U.S. would total .18 acre. Contamination of wells would be avoided through specific drilling requirements and regulations written by the Navajo Nation Department of Water Resources that would apply to these wells and be enforced during construction.	Sam B, e of tl
Biotic Resources	Vegetation would be affected within the right-of-way, primarily during construction (1,205 acres under Alternative B, 766 acres under Alternative C). During construction, habitat removal and alteration would displace wildlife to adjacent habitat with similar vegetation structure; impacts would be minor and localized.	This alternative would result in more acres of surface disturbance (1,373 acres under Alternative B and 829 under Alternative C) and thus more vegetation removal. Impacts on wildlife would be the same as the proposed transmission line. The potential for impacts on federally listed and sensitive species would be the same as	Vegetation (and potential habitat) would be removed on a maximum of 45 acres within the 890-acre well field. Construction and operation of this well field would not be expected to adversely affect any federally listed species.	Veg wou max wel 150 of a pipe recl of tl Mes wer pipe

Resource	Transmission Line		Water-Supply	
	Proposed Transmission Line Segments A, C, and D	**Alternative Transmission Line Segments B, C, D**	**Proposed Well Field Area B**	
	Federally listed and sensitive species could be affected by noise and disturbance during construction. Mesa Verde cactus populations could be affected along Segment D (which is common to both alternatives).	the proposed transmission line.		cou con
Land Use	No residences would be within the proposed right-of-way for Segment A. One residence would be within the right-of-way for Segment D of the proposed transmission line, and a planned burial area would be crossed by Segment C. These uses would be avoided by adjusting the locations of the lattice towers to the extent practicable.	Two residences would be within the right-of-way for Segment B. One residence would be within the right-of-way for Segment D of the proposed transmission line, and a planned burial area would be crossed by Segment C. These uses would be avoided by adjusting the locations of the lattice towers to the extent practicable.	No direct impacts on existing land uses.	No land cou plar prop Cha with this.
Soils and Geology	Impacts of the alternatives would be the same.	Impacts of the alternatives would be the same.	Soil disturbance would occur during construction and maintenance activities.	Gre dist con pipe
Agriculture	Impacts of the alternatives would be the same.	Impacts of the alternatives would be the same.	Minor impacts on grazing from forage removal; no impacts on farming.	Min fora farn this oper redu farn con Cha imp

	Transmission Line		Water-Supply	
Resource	**Proposed Transmission Line Segments A, C, and D**	**Alternative Transmission Line Segments B, C, D**	**Proposed Well Field Area B**	
Visual Resources	Segment A would not parallel existing transmission lines, resulting in a change to existing scenic integrity.	Segment B would parallel existing transmission lines for about 6 miles of its length, reducing new visual impacts.	The visual impact of the well field would be less pronounced, as the viewing conditions in this area would be dominated by the power plant.	The wou und
Socioeconomics	Impacts of the alternatives would be the same.	Impacts of the alternatives would be the same.	Impacts of the alternatives would be the same.	Imp be t
Cultural Resources	23 archaeological and historical properties were identified along Segment A, of which one is listed on the National Register and 19 are Register-eligible. Three Navajo traditional cultural properties, 3 Navajo burials, and 20 Anasazi components that are traditional cultural properties also were identified near Segment A. Impacts may be avoided through sensitive tower placement.	5 archaeological and historical properties were identified along Segment B, and all are considered Register-eligible. Three Navajo burials and 4 Anasazi archaeological sites were identified near Segment B. Impacts may be avoided or mitigated through sensitive tower placement, adherence to the Navajo Nation's Policy for the Protection of *Jishchaa'*, and other mitigation as established in the Programmatic Agreement.	The portion of the well field located on the leased site includes 27 archaeological and historic sites containing 34 historic components, of which 12 are consider Register-eligible. Other potentially affected sites would be the same a described for Segment A of the transmission line. These sites may be avoided through flexible well placement and/or mitigated as established in the Programmatic Agreement.	This Reg Ana be a The loca Nav arch prop Reg
Paleontological Resources	Impacts of the alternatives would be the same.	Impacts of the alternatives would be the same.	Impacts of the alternatives would be the same.	Imp be t
Traffic and Transportation	Short-term impacts may occur on Navajo roads during construction; delays may be encountered on Highway 64 along Segment D where the proposed transmission line would cross the highway.	Same as the proposed alternative.	No additive impact on transportation.	Woi be r

Resource	Transmission Line		Water-Supply	
	Proposed Transmission Line Segments A, C, and D	Alternative Transmission Line Segments B, C, D	Proposed Well Field Area B	
Noise	No sensitive receptors occur within 2 miles.	Sensitive receptors would be within 2,600 feet of Segment B, but noise levels would be below recommended levels during construction.	Impacts of the alternatives would be the same.	Imp be t
Human Health	Impacts of the alternatives would be the same.	Impacts of the alternatives would be the same.	Impacts of the alternatives would be the same.	Imp be t

CONSULTATION AND COORDINATION

The analyses for this Draft EIS were completed in consultation with other agencies and the public. The BIA invited the Navajo Nation and six federal agencies to participate in the preparation of the Desert Rock Energy Project EIS; BIA received five acceptance responses, from (1) Navajo Nation, (2) USEPA, Region IX, (3) OSM, (4) BLM, and (5) USACE. The U.S. Fish and Wildlife Service was the sixth agency invited to be a cooperating agency; however, its participation occurred as part of consultation for Section 7 under the Endangered Species Act. The BIA has and will continue to work closely with the cooperating agencies throughout the EIS process.

BIA hosted a total of nine public scoping meetings, four in December 2004, and another five meetings in March 2005, which were attended by a total of 372 people in three states and numerous local communities. A detailed report of comments and issues heard from the public was developed and placed on the proponent's Desert Rock Energy Project web site at www.desertrockenergy.com, and an informational newsletter (also on the website) detailing the results of the scoping period and the remaining milestones for the EIS was distributed in September 2006.

In addition to the public scoping meetings, Desert Rock Energy Company LLC and its affiliate, Sithe Global, LLC, and DPA held over 50 meetings with local Navajo Chapter residents, Chapter officials, Navajo grazing officials and others in the communities adjacent to the proposed project from 2004 to the present. Comments and information obtained during those meetings were used in developing alternatives and in refining the preliminary project design. Additional information on this and other consultation and coordination efforts is provided in Chapter 6 and Appendix L.

BIA will conduct public hearings on the Draft EIS in June 2007, and comments received during the public review period will be considered and incorporated into the Final EIS.

AGENCIES' PREFERRED ALTERNATIVE

The BIA has proposed a preferred alternative, as follows:

Alternative B – Approval of the long-term lease, rights-of-way, and all associated components of the Desert Rock Energy Project.

<u>Power Plant</u>

Approval of the long-term business land lease between the Navajo Nation and DPA and the sublease between DPA and Desert Rock Energy Project LLC (BIA).

Approval of a National Pollutant Discharge Elimination System (NPDES) permit associated with the power plant (USEPA).

Approval of an individual permit for the proposed power plant under Section 404 of the Clean Water Act and to ensure compliance with the Clean Water Act (USACE).

Approval of water quality certification under Section 401 of the Clean Water Act for the power plant (Navajo Nation).

Coal Supply and Coal Combustion Byproduct (CCB) Disposal

Approval of a significant revision to the BNCC's NPDES permit associated with the mining and reclamation operations and coal preparation facilities (USEPA).

Approval of revisions to BNCC's current SMCRA permit to allow development of coal processing facilities, conveyance systems, and infrastructure in Area IV North of the BNCC lease area (OSM).

Approval of a future SMCRA permit to allow coal mining, CCB disposal, and reclamation activities in Area IV South and Area V of the BNCC lease area (OSM).

Approval of the Resource Recovery and Protection Plan or a Mine Plan of Operations for Area IV South and Area V of the BNCC lease area (BLM).

Approval of nationwide permits or an individual permit for under Section 404 of the Clean Water Act for the mining operations in Area IV South and Area V, and to ensure compliance with Section 404 of the Clean Water Act (USACE).

Approval of water quality certification under Section 401 of the Clean Water Act for the mining operations in Area IV South and Area V (Navajo Nation).

Water-Supply System

Approval to grant the rights-of-way requested for the water-supply system (BIA, Navajo Nation).

Approval of an individual permit for the proposed water-supply system including pipelines under Section 404 of the Clean Water Act and to ensure compliance with Section 404 of the Clean Water Act (USACE).

Approval for use of tribal water resources (Navajo Nation).

Transmission Line (Segments A, C, and D)

Approval to grant the right-of-way requested for the proposed transmission lines (BIA, Navajo Nation).

Approval of an individual permit for the proposed transmission lines under Section 404 of the Clean Water Act and to ensure compliance with Section 404 of the Clean Water Act (USACE).

Access Roads

Approval to grant the right-of-way requested for the proposed access roads (BIA, Navajo Nation).

Approval of an individual permit for the proposed access roads under Section 404 of the Clean Water Act and to ensure compliance with Section 404 of the Clean Water Act (USACE).

1.2 NEED FOR THE ACTION

The Navajo Nation is encouraging development of the proposed Desert Rock Energy Project as part of a broader effort to generate jobs, increase self-sufficiency, and improve the quality of life on the Reservation for the Navajo people. The proposed project would support the Navajo Nation's objective for economic development by providing long-term (1) employment opportunities and (2) revenue cash-flow streams from the sale of power and Navajo Nation natural resources to support the project (e.g., coal, water).

Development of these resources has long been an aim of the Navajo Nation. The Navajo Tribal Council established the DPA in 1985 as an enterprise of the Navajo Nation to engage in energy development for the benefit of the Navajo Nation (21 Navajo Nation Code [NNC] Section 201). Specifically, Section 201 charters DPA to "provide an instrumentality of the Nation to participate in the development of a major coal-fired, mine-mouth steam electric generating station to be located within the extended boundaries of the Navajo Nation in northwestern New Mexico." DPA's goals for the Desert Rock Energy Project are to facilitate tribal self-sufficiency, create significant economic development opportunities, and improve the socioeconomic conditions on the Reservation through responsible and sustainable development of Navajo Nation resources, by generating high-quality jobs and substantial long-term revenues. Because DPA was established on behalf of the Navajo people, the consideration of potential project impacts on tribal members were taken into account during the evaluation of each potential site.

DPA entered into an agreement with Desert Rock Energy to assist in developing the proposed project. The agreement with Desert Rock Energy provides the Navajo Nation with the financial support and resources to develop the Navajo Nation's natural resource of coal. Together, DPA and Desert Rock Energy propose to generate and sell electrical power at competitive prices, using Navajo coal reserves, for the purpose of (1) meeting the forecasted energy demands of the growing populations of the southwestern United States, particularly those in Arizona, New Mexico, and southern Nevada and (2) provide fuel diversity and a stable predictable power supply for utilities in the Southwest.

The need for the proposed project is described in more detail below.

- ***Support the Navajo Nation's objective for economic development by providing long- term employment opportunities and revenue cash-flow streams from the sale of Navajo natural resources (e.g., water, coal).*** The Desert Rock Energy Project would create new employment opportunities and significantly expand the tax base of the Navajo Nation. The project could generate up to 1,600 jobs during the 4-year construction period. In the long term, the project would employ up to 200 people at the power plant and an additional 200 people at the BNCC mine expansion. The project could deliver more than 400 jobs with long-term, direct employment at wage levels averaging more than two times the current full-time Navajo workers' annual average wage of $28,152 (according to the 2000 census). The Desert Rock Energy Project could support direct and indirect economic development for several decades to come.

  Economic benefits to the community would include (1) wage income from new employment at the plant and the mine, (2) income for existing and new businesses from project-related purchases of goods and services and from new wage income circulating in local economies, (3) tax and royalty revenue for the Navajo Nation from the power plant and mine expansion, and (4) additional locally owned businesses developing to support the power plant, mine expansion, and their employees.

Economic development is one of the key goals of the Navajo Nation Government since the economic condition of Navajo tribal members is well below the U.S. average. Based on the 2000 Census, 38.5 percent of all families residing on the Navajo Indian Reservation have a household income below the national poverty level of $16,895 per year. The average per family annual income of $23,992 is a multiple of the average per capita income of $7,578 per year; most families have more than one wage earner contributing to the total. Unemployment rates on the Navajo Indian Reservation exceed 50 percent, and many educated tribal members are unable to return to their homes because of the lack of jobs.

- ***Use Navajo Nation coal to generate electricity.*** The Desert Rock Energy Project would be sited to cost-effectively use Navajo Nation coal resources to fuel the power plant. More than one-half of the total annual direct revenues to the Navajo Nation and one-half the permanent jobs created by the project are a direct result of the use of Navajo Nation coal. Mine-mouth power plants are cost-effective in this region due to the lack of access to rail transportation infrastructure, the higher production costs of Navajo Nation coal, and the lower coal quality (high ash content), as compared to coal resources by rail from the Wyoming Powder River Basin. A mine-mouth power plant is one of the few practical ways to use the Navajo Nation coal resource for the benefit of the Navajo people. It is estimated that the Navajo Indian Reservation overlies abundant coal resources that could be used for power generation. The Desert Rock Energy Project is projected to consume an average of 6.2 million tons per year over the 50-year life of the project.
- ***Help meet the demand for up to 2,000 MW of electrical power in the rapidly growing southwestern United States.*** A new, baseload power plant would provide a reliable and predictable power supply to a region experiencing escalating demand. Between 1990 and 2000, the population of the western region of the United States grew by nearly 20 percent (Perry and Mackun 2001). The Western Electricity Coordinating Council's (WECC) 2005 Ten-Year Coordinated Plan Summary[3] identified the Arizona/New Mexico/Southern Nevada sub-region of the western United States (of which the Four Corners area is a part) as an area in need of additional power generation to sustain growth.
- ***Provide fuel diversity, and provide a more economically stable and predictable power supply for utilities in the Southwest.*** Natural-gas-fired generation presently contributes about 37.3 percent of total generating capacity in the WECC (WECC 2005). Figure 1-1 represents the existing, or installed, generation sources within the WECC as of January 2005. In addition, Figure 1-2 shows WECC planned resource additions for the period from 2005 to 2014. Note that net additions of natural gas resources exceed 80 percent of new resources. The Desert Rock Power Plant and other coal-fired projects currently being permitted or proposed in the Southwest that are not currently included in WECC's planned resources can increase fuel diversity by reducing the need for new natural gas resources. Natural gas prices have increased substantially over the last 3 years and prices have been volatile. The average cost of coal sold to the power plant under long-term contract is forecast to be less than one-third of the cost of natural gas on a per-MMBtu (million British thermal unit) basis. Because this fuel supply can be contracted for as long as 25 years, a coal-fired power plant is exposed to significantly reduced price volatility as compared to natural gas, which is sold typically under maximum contract lengths of three years.

---

[3] Western Systems Coordinating Council (WSCC) was formed with the signing of the WSCC Agreement on August 14, 1967 by 40 electric power systems. Those "charter members" represented the electric power systems engaged in bulk power generation and/or transmission serving all or part of the 14 Western States and British Columbia, Canada. Now known as the WECC, it continues to be responsible for coordinating and promoting electric system reliability as had been done by WSCC since its formation. In addition to promoting a reliable electric power system in the western interconnection, WECC will support efficient competitive power markets, assure open and non-discriminatory transmission access among members, provide a forum for resolving transmission access disputes, and provide an environment for coordinating the operating and planning activities of its members as set forth in the WECC bylaws.

Table 1-2 Southwest Utilities and Estimated Annual Load Growth

Utility Name	2006 Peak Load (MW)	Generation (MW)	Annual Load Growth (MW)
Salt River Project	6,300	5,122	250
Arizona Public Service Company	6,400	6,257	250
Nevada Power Company	6,141	3,066	300
Public Service Company of New Mexico	1,675	1,875	50
Tucson Electric Power	1,900	1,999	50
El Paso Electric	1,282	1,622	50
Navajo Tribal Utility Authority	150	0	5
Total			955

SOURCE: Western Electricity Coordinating Council 2005

Salt River Project (SRP) has issued a request for proposals (RFP) for baseload resources. SRP defines baseload resources as those with a very high availability factor, with availability in the summer being the most critical. SRP would expect at least a 95 percent availability factor in the summer months (June through September). Availability during other months of the year could be reduced to allow maintenance. The products requested would be for a 20-year term, deliverable to the SRP Valley transmission system. The RFP calls for a total of 600 MW of baseload resources in the years 2012 through 2016.

Arizona Public Service (APS) issued an RFP on January 24, 2006, for baseload power for delivery as early as 2009 but no later than 2014, and completed a system study for the Desert Rock Energy Project. APS is seeking proposals for unit-specific baseload generating capacity of 100 MW to 500 MW per unit and will consider proposals offering multi-units at a single site with phased in-service dates. APS will consider proposals that have individual units larger than 500 MW but intends to limit its interest to facilities with no more than 500 MW per unit. Proposed generators must have the ability to operate at or above an 85 percent annual capacity factor. The baseload capacity offered may be for deliveries beginning as early as 2009, but delivery must begin no later than 2014. APS is expected to purchase or self build up to 1,000 MW to meet their project baseload requirements through 2014.

Public Service Company of New Mexico issued an RFP on May 10, 2006, for 229 MW of capacity by 2010. In addition, the RFP indicated a planned capacity need of 515 MW in 2012.

The Southwest Public Power Resources Group, which represents 39 southwest public power utilities, issued an RFP on June 30, 2006, for 400 MW of baseload needs by 2012.

Navajo Tribal Utility Authority has stated an interest in purchasing about 50 MW from the Desert Rock Energy Project to replace a contract they have with Tucson Electric Power that will expire in 2009.

1.3 ISSUES IDENTIFIED DURING SCOPING

As the lead Federal agency, BIA has a responsibility to solicit comments from the public regarding the proposed project and to consult with relevant Federal and State agencies, local governments, and federally recognized American Indian tribes. Scoping is a process that invites public input on the proposed project early in the NEPA process to help determine the scope of issues to be addressed and identify the significant issues related to the proposed action. BIA carried out the NEPA scoping process for the Desert Rock Energy Project.

BIA's notice of intent to prepare an EIS and conduct public scoping meetings was published in the *Federal Register* on November 10, 2004. BIA solicited comments from agencies and the public and hosted public scoping meetings during December 2004 in Phoenix and Flagstaff, Arizona, and Farmington and Gallup, New Mexico. At the request of the public, BIA extended the scoping period and agreed to conduct additional public meetings. A second notice of intent was published in the *Federal Register* on March 10, 2005, announcing the extension of the scoping period and the additional public meetings. The meetings were held in Cortez, Colorado, and Burnham, Sanostee, Shiprock, and Albuquerque, New Mexico in March 2005. The duration of the scoping period, required to be a minimum of 30 days, was 150 days.

Comments received during the scoping period were analyzed and documented in the Desert Rock Energy Project Summary Scoping Report issued in July 2005 and can be found at www.desertrockenergy.com. By the end of the scoping comment period, BIA had received 106 statements made by speakers at public meetings attended by 372 people, and received 1,117 written or electronically mailed submissions.

1.3.1 Summary of Comments

A tribal member of the Four Corners area summed up the feeling of many area residents with a declaration that, "We like to smell the clean air and see the beautiful mountains surrounding us." This statement captures the essence of much community concern about the Desert Rock Energy Project—it simultaneously touches on concerns about air pollution and its effects on health and the local ecosystem, haze and its effects on the social and economic environment, and the yearnings of an American Indian community that has for centuries kept rhythm with the subtle processes of nature. There is a continuum of opinions about the Desert Rock Energy Project—from denouncing the project as just another chapter in a history of exploitation of Native American lands and people, to welcoming of economic opportunity. Many appeared willing to take a wait-and-see attitude and to place their confidence in the EIS process, while some strongly urged that the project go elsewhere or not be developed anywhere.

The preponderance of scoping comments indicated anxiety regarding the cumulative environmental effects of coal-fired power plants in the region. Additionally, some comments questioned the continued use of fossil fuels in light of a near-future pending energy crisis stemming from oil production and concerns about global warming. There were many demands for answers about the additional effects the project would have on the region, and actions that would mitigate those effects, should the project go forward. Some were optimistic about the prospect of economic opportunity, while others expressed great skepticism about the reality or the extent of those opportunities. Three major topics of concern emerged from scoping comments: (1) environmental issues, (2) social and economic issues, and (3) concerns about representation. These are described in more detail below.

1.3.1.1 Environmental Issues

Air quality, global warming, and other global atmospheric effects of burning fossil fuels stood out as the issues of greatest concern. Many commenters expressed fear about the effects of project emissions on community and global health and called for a thorough evaluation of the project's expected effects, including a cumulative impacts analysis, on regional air quality and consideration of alternative non-fossil fuels to generate electricity. Asthma, other respiratory diseases, and cancer were cited as concerns. Others were concerned about the accumulation/disposal of fly ash, mercury, and other heavy metals in the ecosystem, including contamination of groundwater, and one commenter complained about the dangers to children from consuming mercury-contaminated fish. Regional haze, another more visible effect of the cumulative mining and production of electrical power in the area, was the subject of many comments.