BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
REGION 8

DRAFT TITLE V PERMIT TO OPERATE **BONANZA POWER PLANT**	**Draft Permit No. V-UO-000004-00.00**

EXHIBITS A THROUGH E TO COMMENTS OF DESERET GENERATION & TRANSMISSION CO-OPERATIVE

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June 16, 2014

EXHIBIT A

Deseret
Generation & Transmission Co-operative
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801-892-6500 • FAX: 801-892-6599

COPY

Ursula Trueman
Utah Division of Air Quality
1950 West North Temple
Salt Lake City, UT 84004

Attn. J. Tim Blanchard

RE: Request for Approval Order for DG&T Bonanza Unit (1) Power Plant Revised Emission Limits, Change in Coal Pile Parameters and Ruggedized Rotor Project, Uintah County

Dear Ms. Trueman:

Deseret Generation & Transmission Co-operative (DG&T) hereby respectfully submits this notice of intent (NOI) requesting revised emission limits for its Bonanza Unit (1) Power Plant, change in Coal Pile Parameters and Ruggedized Rotor Project. Attachment 1 provides a description of the Ruggedized Rotor Project.

The Ruggedized Rotor Project will increase the overall heat input capacity of the Turbine. The increased heat input has the potential to increase the potential to emit for certain Bonanza 1 emissions. DG&T is voluntarily requesting more stringent emission limits for Bonanza 1 to reduce its NO_x emissions by 528.17 tons per year. DG&T is also requesting certain annual emission limits for other emissions, resulting in an overall increase in the annual potential to emit (PTE) for the Project that is below the levels that might trigger additional review pursuant to new source review (NSR) and prevention of significant deterioration (PSD) requirements. DG&T proposes to increase its PTE for other emissions as follows: particulate emissions 22.60, PM_{10} 14.11 TPY, SO_2 38.21 TPY, CO 91.60 TPY, VOC 10.68 TPY.

DG&T also proposes a change in its Coal Pile parameters to allow the area of the pile to increase to 22 acres and the active reclaim area to increase to 11 acres. The total emission increase from this change will be 3.08 TPY of particulate emissions. The additional emissions will be offset by a reduction in the emission limit for particulate emissions from the tall stack.

The new Coal Pile parameters and Bonanza 1 emission limits are set forth in Attachment 2. A summary of the pre- and post-change emissions are summarized in Attachment 3. Detailed emission data and supporting calculations are set forth in Attachment 4. Also, included with this NOI is a summary of the emission control equipment upgrades completed or planned for Bonanza 1 for which DG&T plans to submit applications for applicable sales tax credits.

If you have any questions or comments regarding the enclosed, please contact Howard Vickers at (435) 781-5706.

Sincerely,

Stan Gordon

Stan Gordon
Plant Manager

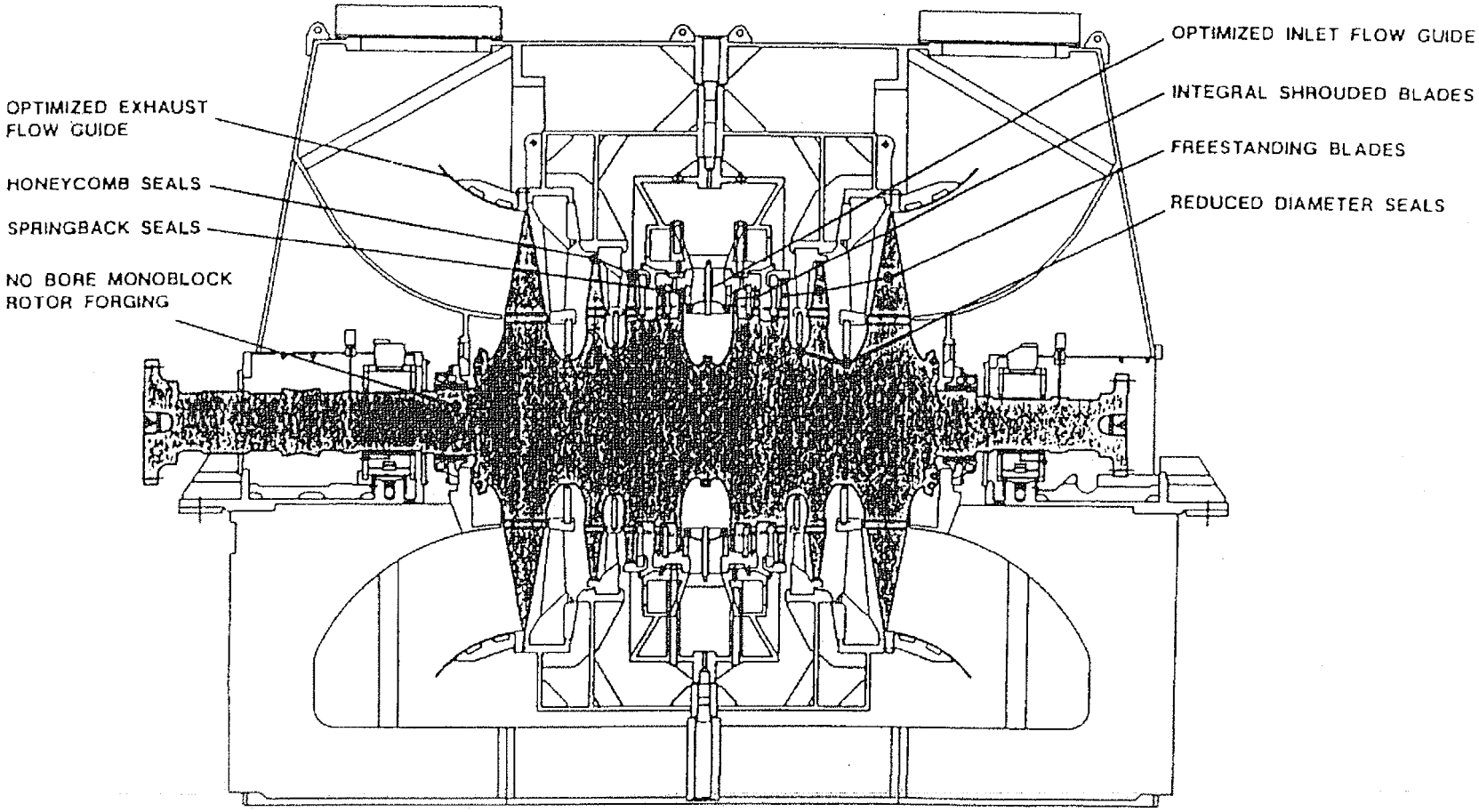
Attachment 1

Ruggedized Rotor Project Description

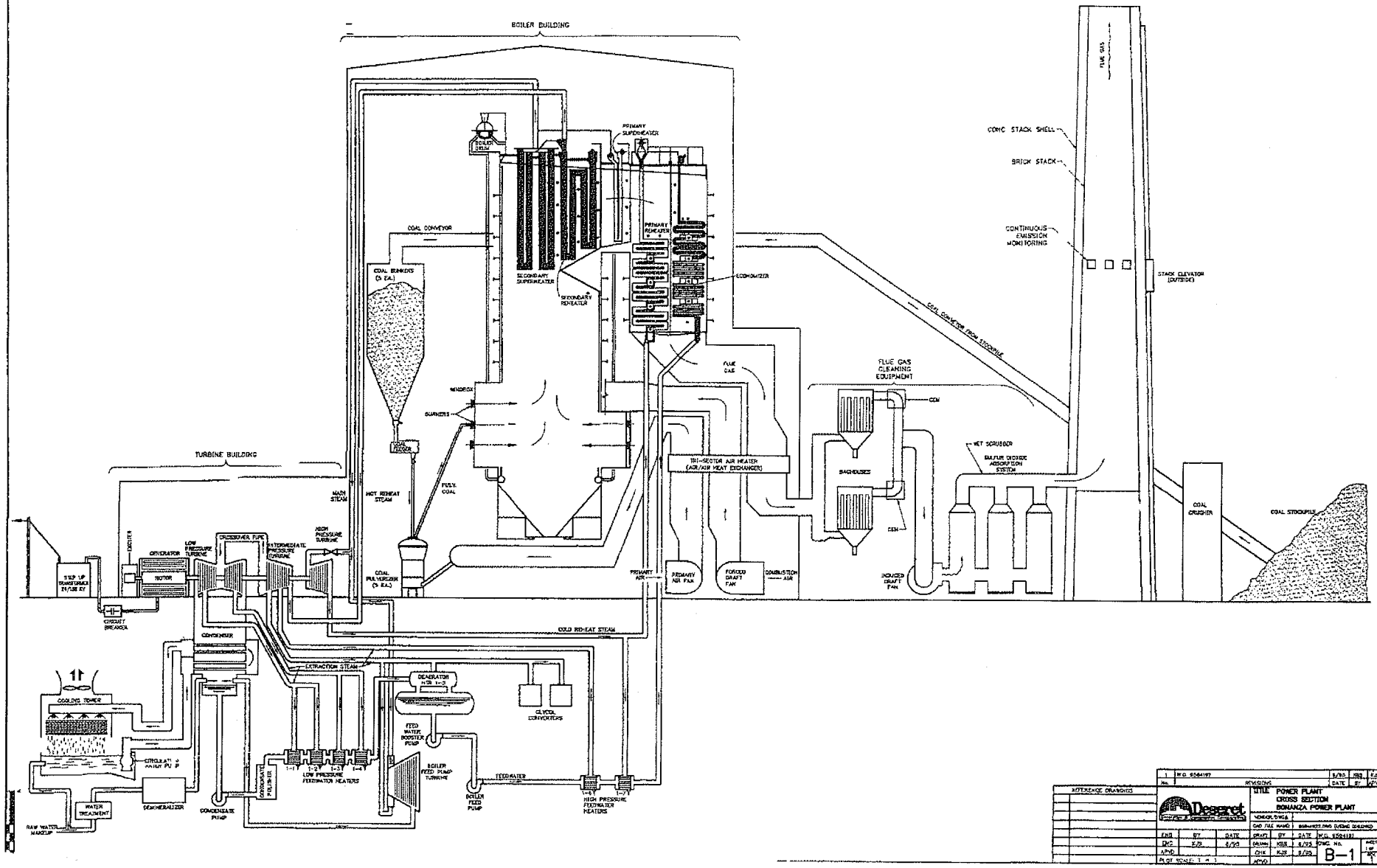
DG&T plans to upgrade the Turbine Generator at Bonanza 1 during the year 2000 or 2001 Unit Outage (A cross section diagram of Bonanza 1 indicating the location of the turbine is attached hereto). The upgrade–referred to as the "Ruggedized Rotor Project"–involves the replacement of the HP/IP and LP rotating and stationary equipment (A cross section diagram of the Ruggedized Rotor LP Rotor is attached hereto). Because the equipment necessary for the Project has a long lead time for design, construction and installation, DG&T is entering into contracts within the next few months to commence construction of the Ruggedized Rotor components. Final installation of the Ruggedized Rotor will take place in the 2000-2001 time frame and is expected to take about 6 weeks. The Project will increase Bonanza 1's generating capacity by at least 28 MW (per vendor representations). DG&T believes that the gross rating of Bonanza 1 could be as much as 500 MW or more (referred to as 500 est. MW) after the upgrade.

Approximately 20 MW from the upgrade will result from an increase in the steam flow produced by the Boiler. To date, the Boiler has not been operated at its peak potential due to limitations of steam flow at the existing Turbine Generator. The Project will allow the Turbine Generator to accept all of the steam flow the Boiler is capable of producing. While the Ruggedized Rotor, by itself, will not result in any change in Bonanza 1's emissions, the increased capacity of the Turbine Generator to handle the Boiler's peak capacity will increase Bonanza 1's overall potential to emit (PTE).

DG&T has prepared this NOI to provide for necessary increases in Bonanza 1's overall PTE to allow operation of the Boiler and Turbine Generator at their full capacity. DG&T also recently installed improved low-NO_x burner technology at the boiler which allows DG&T to voluntarily significantly reduce NO_x emissions. The net effect of the proposed emission changes will be to significantly reduce overall plant wide emissions as a result of lower NO_x limits.



RUGGEDIZED LP ROTOR


BOILER BUILDING
TURBINE BUILDING
PRIMARY SUPERHEATER
SECONDARY SUPERHEATER
SECONDARY REHEATER
PRIMARY REHEATER
ECONOMIZER
COAL CONVEYOR
COAL BUNKERS (5 EA.)
WINDBOX
BURNERS
COAL FEEDER
FULV. COAL
HOT REHEAT STEAM
MAIN STEAM
COAL PULVERIZER (5 EA.)
FLUE GAS
FLUE GAS CLEANING EQUIPMENT
CONC STACK SHELL
BRICK STACK
CONTINUOUS EMISSION MONITORING
STACK ELEVATOR (OUTSIDE)
COAL CONVEYOR FROM STOCKPILE
COAL CRUSHER
COAL STOCKPILE
WET SCRUBBER
SULFUR DIOXIDE ABSORPTION SYSTEM
BAGHOUSES
CEM
INDUCED DRAFT FAN
TRI-SECTOR AIR HEATER (AIR/AIR HEAT EXCHANGER)
PRIMARY AIR
PRIMARY AIR FAN
FORCED DRAFT FAN
COMBUSTION AIR
STEP UP TRANSFORMER (13/138 KV)
CIRCUIT BREAKER
GENERATOR
MOTOR
LOW PRESSURE TURBINE
CROSSOVER PIPE
INTERMEDIATE PRESSURE TURBINE
HIGH PRESSURE TURBINE
COLD RE-HEAT STEAM
CONDENSER
EXTRACTION STEAM
COOLING TOWER
CIRCULATING WATER PUMP
WATER TREATMENT
RAW WATER MAKEUP
DEMINERALIZER
CONDENSATE PUMP
CONDENSATE FILTERS
LOW PRESSURE FEEDWATER HEATERS
DEAERATOR
FEED WATER BOOSTER PUMP
BOILER FEED PUMP TURBINE
BOILER FEED PUMP
FEEDWATER
GLYCOL CONVERTERS
HIGH PRESSURE FEEDWATER HEATERS
REFERENCE DRAWINGS
Deseret
TITLE POWER PLANT CROSS SECTION BONANZA POWER PLANT
B-1

Attachment 2

Proposed New Emission Limits for Bonanza 1

1. **Revise condition 7.A to read as follows:**

   7. Sulfur Emission Control

      A. Bonanza 1 shall not discharge to the atmosphere sulfur as SO_2 at a rate exceeding 0.0976 lb/MM BTU heat input over a rolling 12-month average. Compliance with this emission limitation shall be based on CEM data and fuel heat input. Compliance shall be determined by calculating the rolling 12-month average. On the first day of each month a new 12-month average shall be calculated using data from the previous 12 months.

2. **Revise condition 8.A to read as follows:**

   8. Nitrogen Oxides Emission Control

      A. Bonanza 1 shall not discharge to the atmosphere nitrogen oxide (NO_x) at a rate exceeding 0.50 lb/MM BTU heat input on an annual average. Compliance with this emission limitation shall be based on CEM data and fuel heat input. Compliance shall be determined in accordance with 40 CFR 76.5(b).

3. **Revise condition 9.A to read as follows:**

   9. Particulate and PM_{10} Emission Control

      A. Unit No. 1 shall not discharge to the atmosphere particulate matter at a rate exceeding 0.0297 lbs/MMBTU heat input as determined by 40 CFR 60, Appendix A, Methods 1-5 and 19.

4. **Revise condition 9.B to read as follows:**

   9.B Unit No. 1 shall not discharge to the atmosphere PM_{10} particulate matter at a rate exceeding 0.0286 lbs/MMBTU heat input as determined by 40 CFR 60, Appendix A, Methods 1, 2, 4,5-5e and 19.

5. **Revise condition 13 to read as follows:**

   13. The coal pile shall not exceed 22 acres in total area. The active reclaim area shall not exceed 11 acres at any one time. The reclaim area may be moved to any location on the coal pile. The remainder of the coal pile shall be the long-term storage area. Emissions of particulate from the long-term storage area shall be

controlled by compaction of the coal pile surface and sealing with a surfactant initially and be subsequent application of sealing agent as warranted. A surfactant and spray mechanism to apply it shall be available and operative at all times. Conditions which warrant application of the surfactant are defined as any time the 20% opacity limitation is in jeopardy of being violated. A log of operation shall be kept. The log shall include:

A. Times of spray operation
B. Compaction operation
C. Weather conditions
D. Surface conditions (dry, crumbled, moist, etc.)

Attachment 3

Net Emission Changes

Pollutant	Pre-Change Emissions TPY	Post-Change Emissions TPY	Net Change TPY
CO	510.85	602.45	91.60
VOC	60.21	70.89	10.68
NO_x	10558.00	10029.83	**<528.17>**
SO_2	1929.90	1968.11	38.21
PM	939.96	962.56	22.60
PM_{10}	911.65	925.76	14.11
HAPS	55.77 6.19	60.46 10.89	4.69 4.65
Totals	14966.34	14,620.06	**<346.28>** 346.32
	14916.~~88~~	14,520.44	
Net Emissions Decrease	16		**<346.28>** 346.32

Attachment 3 cont.

PM_{10} Emission Source Summary

Emission Source	Pre Change Emissions	Post change Emissions	Net Change
Boiler- coal [a]	575.60	589.52	13.92
Boiler- fuel oil [a]	0.05	0.05	0.00
Auxiliary Boiler	0.03	0.03	0.00
Emergency Generator	0.06	0.06	0.00
Fire Pump	0.02	0.02	0.00
Construction Heaters	0.00	0.00	0.00
Access Road	1.77	1.77	0.00
Perimeter Road	1.05	0.29	<0.76>
Coal Reclaim	0.32	0.43	0.11
Coal Unloading [a]	0.01	0.01	0.00
Coal Conveyors 1&2 [a]	0.00	0.00	0.00
Coal Conveyors 3,4&5 [a]	0.00	0.00	0.00
Coal Crusher [a]	0.46	0.46	0.00
Coal Pile loadout [a]	0.04	0.04	0.00
Coal Pile wind Erosion	0.02	0.02	0.00
Limestone Conveyors 1&2 [a]	0.00	0.00	0.00
Dozers on the Limestone Piles	0.01	0.01	0.00
Limestone pile Wind Erosion	1.58	2.38	0.80
Sludge Pile Conveyors	0.13	0.14	0.01
Dozers on the Sludge Pile	0.09	0.11	0.02
Sludge Pile Wind Erosion	12.01	12.01	0.00
Cooling Tower Drift	318.40	318.40	0.00
Totals	911.65	925.76	14.11

Net change for fugitives	0.19
Net change for point sources	13.92

[a] Non fugitive sources

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL & ASH HANDLING OPERATIONS
SOURCE DESCRIPT: ACCESS HAUL ROAD

PROCESS DATA

YEAR: 1995 SCC CODE	ROAD SILT CONTENT (%)	MEAN VEHICLE SPEED (MPH)	MEAN VEHICLE WEIGHT (TONS)	MAXIMUM & ACTUAL MILES TRAVELED		MEAN NO. OF WHEELS	DAYS W/ > 0.01" RAIN PER YEAR	HAUL DISTANCE ROUNDTRIP (MILES)	TRUCK CAPACITY (TONS)
30300833	5.00	25	10	7,000	M	8	60	2	10.00
				5,120	A				

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%) (EPRI)	EMISSION FACTOR (LBS/VMT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Watering	Chemical	75.00	5.6234		AP-42	3.60	1.12	4.92
PM10	Watering	Chemical	75.00	2.0244		AP-42	1.30	0.40	1.77

NOTES:

AP-42 EQUATION - UNPAVED ROADS (PM & PM10)

E = k(5.9)(s/12)(S/30)(W/3)^0.7 (w/4)^0.5 ((365-p)/365) lbs/VMT

where:

E = emission factor (lbs/VMT)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.36

s = silt content of road surface material (%); Estimated to be 5% based on information published in EPRI for gravel roads

S = mean vehicle speed (mph); Estimated to be 25

W = mean vehicle weight (ton); Estimated to be 10 tons (the wt. which gives an avg emissions factor to account for loaded and unloaded hauling wts)

w = mean number of wheels; Estimated to be 8

p = number of days with >= 0.01 inches of precipitation per year; Estimated to be 95 based on AP-42 weather chart

VMT = vehicle miles traveled; Estimated based on a roundtrip distance of 2 miles (measured) and an estimated average truck capacity of 10 tons

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of periodic watering or chemical addition on an as-needed basis.

5) Control efficiency for watering based on information published in EPRI.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: SECURITY OPERATIONS
SOURCE DESCRIPT: PERIMETER ROAD

PROCESS DATA

YEAR: 1995 SCC CODE	ROAD SILT CONTENT (%)	MEAN VEHICLE SPEED (MPH)	MEAN VEHICLE WEIGHT (TONS)	MAXIMUM & ACTUAL MILES TRAVELED		MEAN NO. OF WHEELS	DAYS W/ > 0.01" RAIN PER YEAR	HAUL DISTANCE ROUNDTRIP (MILES)
30300833	5.00	25	1	2,000	M	4	60	2
				1,500	A			

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/VMT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			(EPRI) 0.00	0.7934		AP-42	0.60	0.18	0.79
PM10			0.00	0.2856		AP-42	0.21	0.07	0.29

NOTES:

AP-42 EQUATION - UNPAVED ROADS (PM & PM10)

E = k(5.9)(s/12)(S/30)(W/3)^0.7 (w/4)^0.5 ((365-p)/365) lbs/VMT

where:

E = emission factor (lbs/VMT)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.36

s = silt content of road surface material (%); Estimated to be 5% based on information published in EPRI for gravel roads

S = mean vehicle speed (mph); Estimated to be 25

W = mean vehicle weight (ton); Estimated to be 10 tons (the wt. which gives an avg emissions factor to account for loaded and unloaded hauling wts)

w = mean number of wheels; Estimated to be 8

p = number of days with >= 0.01 inches of precipitation per year; Estimated to be 95 based on AP-42 weather chart

VMT = vehicle miles traveled; Estimated based on a roundtrip distance of 2 miles (measured) and an estimated average truck capacity of 10 tons

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of periodic watering or chemical addition on an as-needed basis.

5) Control efficiency for watering based on information published in EPRI.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: INACTIVE STORAGE - WIND EROSION, (p. 8 of 8)
rev. 2

PROCESS DATA

YEAR: 1997 SCC CODE	COAL SILT CONTENT (%)	TIME WINDSPEED EXCEEDS 12 MPH AT MEAN PILE HT (%)	MAXIMUM & ACTUAL PILE SIZE (ACRES)	SCC UNITS	NO. DAYS WITH >= 0.01" PRECIP PER YEAR
	0.01	29.50	22.00	M TON	80
		(Estimated)	22.00	A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/DAY/ACRE)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Chemical	Compaction	(EPRI) 50.00	0.0289		AP-42	0.06	0.01	0.06
PM10	Chemical	Compaction	50.00	0.0145		ENGR JUDGMT	0.03	0.01	0.03

NOTES:

AP-42 EQUATION - WIND EROSION OF STORAGE PILES

E = 1.7 (s/1.5)((365-p)/235)(f/15) lb/day/acre

where:

E = emission factor (lb/day/acre)

s = silt content of aggregate (%); Estimated to be 6.2% based on data published in AP-42 and EPRI for western coal.

p = number of days with >= 0.01 inch of precipitation per year; Estimated to be 85 based on AP-42 weather chart.

f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to be 29.5% based on climatological summary for local airport

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

3) Emissions control consists of periodic watering.
4) Control efficiency for PM based on data published in EPRI.
5) Control efficiency for PM10 based on engineering judgement.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: DOZER RECLAIM (p.1 of 8)
rev. 2

PROCESS DATA

YEAR: 1997 SCC CODE		SILT CONTENT (%)	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS	MOISTURE CONTENT (%)			
30501040		0.01	10.00	2,000,000	M	TON	12.00			
			(Average)	1,100,000	A					

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	(TONS/YEAR)
PM			0.00	0.01234		AP-42	6.79	2.82	12.34
PM10			0.00	0.00043		AP-42	0.24	0.10	0.43

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

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

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10.9 mph based on climatology data from local airport

M = material moisture content (%); Estimated to be 4.5% based on AP-42 and EPRI data

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on 100% fuel delivery by truck, full load unlimited operation of combustion units, and a coal heat content of 8,200 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) No emissions control equipment.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: RAILCAR AND TRUCK UNLOADING, (p.2 of 8)
rev. 2

PROCESS DATA

YEAR: 1997										
SCC CODE			MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE		SCC UNITS	MOISTURE CONTENT (%)			
			10.00	2,008,000		TON	12.00			
			(Estimated)	1,700,000	A		(Recieved)			

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Dust Suppression		(Estimated) 95.00	0.00064		AP-42	0.027	0.007	0.032
PM10	Dust Suppression		(Estimated) 95.00	0.00022		AP-42	0.010	0.003	0.011

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

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

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.

M = material moisture content (%); 6% recieved, based on plant data worse case.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on 100% fuel delivery by train or truck, full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: CONV. 1 AND 2 TO STORAGE, (p. 3 of 8)
rev. 2

PROCESS DATA

YEAR: 1997		NUMBER OF TRANSFER POINTS	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS	MOISTURE CONTENT (%)
SCC CODE						
30501011		3	10.00	2,006,000	TON	12.00
			(Estimated)	1,700,000 A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Fabric Filter	Dust Suppression	(EPRI: EPA) 99.70	0.00064		AP-42	0.00	0.00	0.01
PM10	Fabric Filter	Dust Suppression	(Calculated) 99.27	0.00022		AP-42	0.00	0.00	0.00

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

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

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.

M = material moisture content (%); 6% recieved based on plant data worse case.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: CONVs. 3,4, AND 5 TO PLANT, (p. 4 of 6)
rev. 2

PROCESS DATA

YEAR: 1997									
SCC CODE		NUMBER OF TRANSFER POINTS	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS	MOISTURE CONTENT (%)			
30501011		3	10.00	2,006,000	TON	12.00			
			(Estimated)	1,700,000	A				

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Fabric Filter		(EPRI: EPA) 99.70	0.00064		AP-42	0.00	0.00	0.00
PM10	Fabric Filter		(Calculated) 99.27	0.00022		AP-42	0.00	0.00	0.00

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

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

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.

M = material moisture content (%); 6% recieved based on plant data worse case.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: COAL CRUSHING, (p. 5 of 8)
rev. 2

PROCESS DATA

YEAR:	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS
1997		
SCC CODE		
	2,008,000	TON
	1,700,000 A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Fabric Filter		(EPRI: EPA) 99.70	0.1800		EPRI	0.46	0.12	0.54
PM10	Fabric Filter		(Calculated) 99.49	0.0900		ENGR JUDGMT	0.39	0.10	0.46

NOTES:

ACTUAL 1994 EMISSIONS

1) Actual emissions based on emissions factor published in EPRI and engineering judgement, as noted for each pollutant.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on emissions factor published in EPRI and engineering judgement, as noted for each pollutant.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COAL HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: ACTIVE STORAGE - LOAD-IN BY CONVEYOR 1, (p. 5 of 8)
rev.2

PROCESS DATA

YEAR:	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS	MOISTURE CONTENT (%)
1997				
SCC CODE				
	10.00	1,500,000	TON	12.00
	(Estimated)	550,000 A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Dust Suppression		(AWMA) 75.00	0.00064		AP-42	0.04	0.03	0.12
PM10	Dust Suppression		75.00	0.00022		AP-42	0.02	0.01	0.04

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

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

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.

M = material moisture content (%); 6% recieved based on plant data worse case.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the esaumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: LIMESTONE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: CONVs. L1 AND L2 (p. 1 of 3)
rev. 2

PROCESS DATA

YEAR: 1997		NUMBER OF TRANSFER POINTS	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS	MOISTURE CONTENT (%)
SCC CODE						
30501011		3	10.00	60,000	TON	3.00
			(Estimated)	40,000 A.		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	PROCESS CONTROLLED EMISSIONS (LBS/HR)	PROCESS CONTROLLED EMISSIONS (TONS/YEAR)
PM	Fabric Filter		(EPRI: EPA) 99.70	0.00447		AP-42	0.00	0.00	0.00
PM10	Fabric Filter		(Calculated) 99.43	0.00156		AP-42	0.00	0.00	0.00

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

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

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.

M = material moisture content (%); 6% recieved based on plant data worse case.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: LIMESTONE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: DOZERS ON STORAGE PILE (p. 2 of 3)
rev. 2

PROCESS DATA

YEAR: 1997 SCC CODE	LIMESTONE SILT CONTENT (%)	MEAN VEHICLE SPEED (MPH)	MEAN VEHICLE WEIGHT (TONS)	MAXIMUM & ACTUAL MILES TRAVELED	SCC UNITS	MEAN NO. OF WHEELS	DAYS W/ > 0.01" RAIN PER YEAR
	1.50	5	10	300	TON	4	60
				150 A			

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/VMT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			(EPRI) 0.00	0.2366		AP-42	0.02	0.01	0.04
PM10			0.00	0.0659		AP-42	0.01	0.00	0.01

NOTES:

AP-42 EQUATION - UNPAVED ROADS (PM & PM10)

E = k(5.9)(s/12)(S/30)(W/3)^0.7 (w/4)^0.5 ((365-p)/365) lbs/VMT

where:

E = emission factor (lbs/VMT)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.36

s = silt content of surface material (%); Estimated to be 6.2% based on information published in AP-42 and EPRI for western coal.

S = mean vehicle speed (mph); Estimated to be 5 mph

W = mean vehicle weight (ton); 10 tons

w = mean number of wheels; 4

p = number of days with >= 0.01 inches of precipitation per year; Estimated to be 85 based on AP-42 weather chart

VMT = vehicle miles traveled; Estimated based on an average of 8 dozer-hours on piles per day

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum rate based on 16 dozer-hours on piles per day.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of periodic watering on an as-needed basis.
5) Control efficiency for watering based on information published in EPRI.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: LIMESTONE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: ACTIVE STORAGE - WIND EROSION (p. 3 of 3)
rev. 2

PROCESS DATA

YEAR: 1997 SCC CODE	LIMESTONE SILT CONTENT (%)	TIME WINDSPEED EXCEEDS 12 MPH AT MEAN PILE HT (%)	MAXIMUM & ACTUAL PILE SIZE (ACRES)	SCC UNITS	NO. DAYS WITH >= 0.01" PRECIP PER YEAR
	1.50	29.50	6.00	TON	60
		(Estimated)	2.00 A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/DAY/ACRE)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			(EPRI) 0.00	4.3392		AP-42	1.58	1.08	4.75
PM10			0.00	2.1696		ENGR JUDGMT	0.79	0.54	2.38

NOTES:

AP-42 EQUATION - WIND EROSION OF STORAGE PILES

$E = 1.7\ (s/1.5)((365-p)/235)(f/15)$ lb/day/acre

where:

E = emission factor (lb/day/acre)

s = silt content of aggregate (%); Estimated to be 6.2% based on data published in AP-42 and EPRI for western coal.

p = number of days with >= 0.01 inch of precipitation per year; Estimated to be 85 based on AP-42 weather chart.

f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to be 29.5% based on climatological summary from PSD and NOI.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

3) Emissions control consists of periodic watering.
4) Control efficiency for PM based on data published in EPRI.
5) Control efficiency for PM10 based on engineering judgement.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: SLUDGE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: CONVs. S1, S2, S3, S4, S5, S6, and RADIAL STACKER (p. 2 of 4)
rev. 2

PROCESS DATA

YEAR: 1997		NUMBER OF TRANSFER POINTS	MEAN WIND SPEED (MPH)	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS	MOISTURE CONTENT (%)
SCC CODE						
30501011		7	10.00	245,000	TON	15.00
			(Estimated)	145,000 A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			0.00	0.00047		AP-42	0.24	0.09	0.40
PM10			0.00	0.00016		AP-42	0.08	0.03	0.14

NOTES:

AP-42 EQUATION - BATCH OR CONTINUOUS DROP OPERATIONS

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

where:

E = emission factor (lbs/ton)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

U = mean wind speed (mph); Estimated to be 10 mph based on climatology data from PSD and NOI.

M = material moisture content (%); 6% recieved based on plant data worse case.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum process rate based on full load unlimited operation of combustion units, and a coal heat content of 9,381 Btu/lb.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for batch or continuous drop operations.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of a fabric filter.
5) Control efficiency for PM based on data published in EPRI and supported by vendor information.
6) Control efficiency for PM10 calculated based on the assumption that all PM escaping control is PM10.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: SLUDGE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: DOZERS ON STORAGE PILE (p. 3 of 4)
rev. 2

PROCESS DATA

YEAR: 1997 SCC CODE	SLUDGE SILT CONTENT (%)	MEAN VEHICLE SPEED (MPH)	MEAN VEHICLE WEIGHT (TONS)	MAXIMUM & ACTUAL MILES TRAVELED	SCC UNITS	MEAN NO. OF WHEELS	DAYS W/ > 0.01" RAIN PER YEAR
	6.50	5	10	1,200	TON	4	60
				800 A			

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/VMT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Watering		(EPRI) 50.00	1.0338		AP-42	0.21	0.07	0.31
PM10	Watering		50.00	0.3722		AP-42	0.07	0.03	0.11

NOTES:

AP-42 EQUATION - UNPAVED ROADS (PM & PM10)

E = k(5.9)(s/12)(S/30)(W/3)^0.7 (w/4)^0.5 ((365-p)/365) lbs/VMT

where:

E = emission factor (lbs/VMT)

k = particle size multiplier (dimensionless); PM = 1 and PM10 = 0.35

s = silt content of surface material (%); Estimated to be 6.2% based on information published in AP-42 and EPRI for western coal.

S = mean vehicle speed (mph); Estimated to be 5 mph

W = mean vehicle weight (ton); 10 tons

w = mean number of wheels; 4

p = number of days with >= 0.01 inches of precipitation per year; Estimated to be 85 based on AP-42 weather chart

VMT = vehicle miles traveled; Estimated based on an average of 8 dozer-hours on piles per day

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

POTENTIAL CONTROLLED EMISSIONS

2) Maximum rate based on 16 dozer-hours on piles per day.
3) Potential emissions based on calculated emissions factors using the above AP-42 equation for unpaved roads.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

4) Emissions control equipment consists of periodic watering on an as-needed basis.
5) Control efficiency for watering based on information published in EPRI.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: SLUDGE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: ACTIVE STORAGE - WIND EROSION (p. 4 of 4)
rev. 2

PROCESS DATA

YEAR: 1997	SLUDGE SILT CONTENT (%)	TIME WINDSPEED EXCEEDS 12 MPH AT MEAN PILE HT (%)	MAXIMUM & ACTUAL PILE SIZE (ACRES)	SCC UNITS	NO. DAYS WITH >= 0.01" PRECIP PER YEAR
SCC CODE					
	6.50	29.50	14.00	TON	60
		(Estimated)	14.00 A		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/DAY/ACRE)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM	Watering		(EPRI) 50.00	18.8033		AP-42	24.02	5.48	24.02
PM10	Watering		50.00	9.4016		ENGR JUDGMT	12.01	2.74	12.01

NOTES:

AP-42 EQUATION - WIND EROSION OF STORAGE PILES

$E = 1.7 (s/1.5)((365-p)/235)(f/15)$ lb/day/acre

where:

E = emission factor (lb/day/acre)

s = silt content of aggregate (%); Estimated to be 6.2% based on data published in AP-42 and EPRI for western coal.

p = number of days with >= 0.01 inch of precipitation per year; Estimated to be 85 based on AP-42 weather chart.

f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to be 29.5% based on climatological summary from PSD and NOI.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

3) Emissions control consists of periodic watering.
4) Control efficiency for PM based on data published in EPRI.
5) Control efficiency for PM10 based on engineering judgement.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: RAW LIMESTONE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: ACTIVE STORAGE - WIND EROSION (p. 3 of 3)
rev. 2

YEAR: 1997 SCC CODE	LIMESTONE SILT CONTENT (%)	TIME WINDSPEED EXCEEDS 12 MPH AT MEAN PILE HT (%)	PROCESS DATA MAXIMUM & ACTUAL PILE SIZE (ACRES)	SCC UNITS	NO. DAYS WITH >= 0.01" PRECIP PER YEAR
	0.50	29.50 (Estimated)	3.00 / 2.00 A	TON	60

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/DAY/ACRE)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			(EPRI) 0.00	1.4464		AP-42	0.53	0.18	0.79
PM10			0.00	0.7232		ENGR JUDGMT	0.26	0.09	0.40

NOTES:

AP-42 EQUATION - WIND EROSION OF STORAGE PILES

E = 1.7 (s/1.5)((365-p)/235)(f/15) lb/day/acre

where:

E = emission factor (lb/day/acre)

s = silt content of aggregate (%); Estimated to be 6.2% based on data published in AP-42 and EPRI for western coal.

p = number of days with >= 0.01 inch of precipitation per year; Estimated to be 85 based on AP-42 weather chart.

f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to be 29.5% based on climatological summary from PSD and NOI.

ACTUAL 1994 EMISSIONS

1) Actual emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

3) Emissions control consists of periodic watering.
4) Control efficiency for PM based on data published in EPRI.
5) Control efficiency for PM10 based on engineering judgement.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: BALLAST LIMESTONE HANDLING & STORAGE OPERATIONS
SOURCE DESCRIPT: ACTIVE STORAGE - WIND EROSION (p. 3 of 3)
rev. 2

YEAR: 1997 SCC CODE	LIMESTONE SILT CONTENT (%)	TIME WINDSPEED EXCEEDS 12 MPH AT MEAN PILE HT (%)	PROCESS DATA MAXIMUM & ACTUAL PILE SIZE (ACRES)	SCC UNITS	NO. DAYS WITH >= 0.01" PRECIP PER YEAR
	1.00	29.50 (Estimated)	2.00 / 2.00 A	TON	60

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/DAY/ACRE)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM			(EPRI) 0.00	2.8928		AP-42	1.06	0.24	1.06
PM10			0.00	1.4464		ENGR JUDGMT	0.53	0.12	0.53

NOTES:

AP-42 EQUATION - WIND EROSION OF STORAGE PILES

$E = 1.7 (s/1.5)((365-p)/235)(f/15)$ lb/day/acre

where:

E = emission factor (lb/day/acre)

s = silt content of aggregate (%); Estimated to be 6.2% based on data published in AP-42 and EPRI for western coal.

p = number of days with >= 0.01 inch of precipitation per year; Estimated to be 85 based on AP-42 weather chart.

f = time unobstructed wind speed exceeds 12 mph at the mean pile height (%); Estimated to be 29.5% based on climatological summary from PSD and NOI.

ACTUAL 1994 EMISSIONS

1) *Actual emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.*

POTENTIAL CONTROLLED EMISSIONS

2) Potential emissions based on calculated emissions factors using the above AP-42 equation for wind erosion of storage piles.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

3) Emissions control consists of periodic watering.
4) Control efficiency for PM based on data published in EPRI.
5) Control efficiency for PM10 based on engineering judgement.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: FUEL OIL STORAGE TANK 1- 268,000 GALLONS
SOURCE DESCRIPT: No. 2 Fuel Oil Evaporation

YEAR:				PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS				
1995									
SCC CODE									
40400413				283,000	GAL				
				168,809	A				

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			0.00	0.0036		AP-42	0.30	0.12	0.53
HAPs			0.00	0.0000		ENGR JUDGMT	0.00	0.00	0.00

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual VOC emissions. Actual plant data was used in the VOC calculations.
2) Actual 1995 HAPs emissions negligible.

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is based on the maximum (approximate) amount of fuel oil which could be burned by the combustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual plant data was used in the VOC calculations.
5) Potential 1995 HAPs emissions insignificant.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

6) There is no emissions control equipment.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: FUEL OIL STORAGE TANK 2- 268,000 GALLONS
SOURCE DESCRIPT: No. 2 Fuel Oil Evaporation

PROCESS DATA

YEAR: 1995	MAQXIMUM & ACTUAL PROCESS RATE	SCC UNITS
SCC CODE		
40400413	0.00	GAL
	0.00 A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			0.00	0.2100		AP-42	0.00	0.00	0.00
HAPs			0.00	0.0000		ENGR JUDGMT	0.00	#DIV/0!	0.00

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual VOC emissions. Actual plant data was used in the VOC calculations.
2) Actual 1995 HAPs emissions negligible.

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is based on the maximum (approximate) amount of fuel oil which could be burned by the combustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual plant data was used in the VOC calculations.
5) Potential 1995 HAPs emissions insignificant.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

6) There is no emissions control equipment.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: COOLING TOWER
SOURCE DESCRIPT: Drift and Evaporation
rev. 2

YEAR: 1997 SCC CODE	AVERAGE DRIFT RATE (SCC UNIT/HR)	AVERAGE EVAPORATION RATE (SCC UNIT/HR)	AVERAGE TEMPERATURE DIFFERENTIAL (F)	PROCESS RATE MAXIMUM & ACTUAL PROCESS RATE (GPM)	SCC UNITS	RECIRC RATE (SCC UNIT/HR)	CHLORINE RESIDUAL 3-HR SHOCK (ppm)	TDS IN CIRC WATER (ppm)	DRIFT % OF RECIRC (%)
	11.85	210	23	125,000	GALS^3	7,500	0.05	8,000	0.00158
				125,000	A		0.05		

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)	ASH/SULFUR FLAG	EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
PM10	Drift Eliminators		(CALCULATED) 76.93	0.0126		AP-42, 13-4	318.42	72.70	318.42
Chlorine									

NOTES:

ACTUAL 1997 EMISSIONS

1) Actual PM and PM10 emissions calculated based on drift rate and total disolved solids (TDS) in recirculation water.
2) Actual chlorine emissions calculated based on a continuous Cl2 level of 0.0 ppm and a daily shock chlorination level of 0.05 ppm for three hours.

POTENTIAL CONTROLLED EMISSIONS

3) Potential controlled emissions are based on maximum capacity and unlimited hours of operation (8,760 hrs/yr).
4) Potential PM and PM10 emissions calculated based on drift rate and total disolved solids (TDS) in recirculation water.
5) Potential chlorine emissions calculated based on a continuous Cl2 level of 0.0 ppm and a daily shock chlorination level of 0.05 ppm for three hours.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

6) Emissions control equipment consists of drift eliminators.
7) Control efficiencies for drift eliminators calculated based on comparing calculated controlled emissions to predicted uncontrolled emissions using AP-42 emissions factors.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: UNLEADED GASOLINE UST - 1,000 GALLONS
SOURCE DESCRIPT: Fuel Evaporation

YEAR:	PROCESS DATA MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS
1995		
SCC CODE		
	20,000	GAL
	17,000 A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			0.00	SEE NOTES (1) & (4)		AP-42	0.11	0.03	0.13
HAPs			0.00	SEE NOTES (1) & (4)		ENGR JUDGMT	5.50E-03	1.48E-03	6.50E-03

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual 1995 VOC emissions.
2) The unleaded gasoline was assumed to have a Reid Vapor Pressure of 13 (RVP 13).
3) Actual 1995 HAPs emissions calculated as a percentage of VOC emissions (5% by weight for typical gasoline), based on EPA information. HAPs may include benzene, toluene, hexane, ethylbenzene, napthalene, cumene, xylenes, n-hexane, 2,2,4-trimethylpentane, MBTE, and others.

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is estimated.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions.
5) The unleaded gasoline was assumed to have a Reid Vapor Pressure of 13 (RVP 13).
6) Potential 1995 HAPs emissions calculated as a percentage of VOC emissions (5% by weight for typical gasoline), based on EPA information. HAPs may include benzene, toluene, hexane, ethylbenzene, napthalene, cumene, xylenes, n-hexane, 2,2,4-trimethylpentane, MBTE, and others.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

7) There is no emissions control equipment.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: UNLEADED GASOLINE UST - 1,000 GALLONS
SOURCE DESCRIPT: Fuel Evaporation

PROCESS DATA

YEAR: 1995	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS
SCC CODE	20,000	GAL
	17,000	A

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			0.00	SEE NOTES (1) & (4)		AP-42	0.11	0.03	0.13
HAPs			0.00	SEE NOTES (1) & (4)		ENGR JUDGMT	5.50E-03	1.48E-03	6.50E-03

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual 1995 VOC emissions.
2) The unleaded gasoline was assumed to have a Reid Vapor Pressure of 13 (RVP 13).
3) Actual 1995 HAPs emissions calculated as a percentage of VOC emissions (5% by weight for typical gasoline), based on EPA information. HAPs may include benzene, toluene, hexane, ethylbenzene, napthalene, cumene, xylenes, n-hexane, 2,2,4-trimethylpentane, MBTE, and others.

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is estimated.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions.
5) The unleaded gasoline was assumed to have a Reid Vapor Pressure of 13 (RVP 13).
6) Potential 1995 HAPs emissions calculated as a percentage of VOC emissions (5% by weight for typical gasoline), based on EPA information. HAPs may include benzene, toluene, hexane, ethylbenzene, napthalene, cumene, xylenes, n-hexane, 2,2,4-trimethylpentane, MBTE, and others.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

7) There is no emissions control equipment.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: FUEL OIL STORAGE TANK 1- 268,000 GALLONS
SOURCE DESCRIPT: No. 2 Fuel Oil Evaporation

PROCESS DATA

YEAR:	SCC CODE	MAXIMUM & ACTUAL PROCESS RATE	SCC UNITS
1995	40400413	293,000	GAL
		166,809 A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			0.00	0.0036		AP-42	0.30	0.12	0.53
HAPs			0.00	0.0000		ENGR JUDGMT	0.00	0.00	0.00

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual VOC emissions. Actual plant data was used in the VOC calculations.
2) Actual 1995 HAPs emissions negligible.

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is based on the maximum (approximate) amount of fuel oil which could be burned by the combustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual plant data was used in the VOC calculations.
5) Potential 1995 HAPs emissions insignificant.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

6) There is no emissions control equipment.

DESERET GENERATION AND TRANSMISSION COOPERATIVE

PLANT: Bonanza, Unit 1
SOURCE ID: FUEL OIL STORAGE TANK 2- 288,000 GALLONS
SOURCE DESCRIPT: No. 2 Fuel Oil Evaporation

YEAR:	PROCESS DATA MAQXIMUM & ACTUAL PROCESS RATE	SCC UNITS
SCC CODE		
1995		
40400413	0.00	GAL
	0.00 A	

ESTIMATED EMISSIONS

POLLUTANT	CONTROL EQUIPMENT PRIMARY	CONTROL EQUIPMENT SECONDARY	OVERALL CONTROL EFFICIENCY (%)	EMISSION FACTOR (LBS/SCC UNIT)		EMISSIONS ESTIMATION METHOD	ACTUAL CONTROLLED (TONS/YEAR)	POTENTIAL CONTROLLED EMISSIONS (LBS/HR)	POTENTIAL CONTROLLED EMISSIONS (TONS/YEAR)
VOC			0.00	0.2100		AP-42	0.00	0.00	0.00
HAPs			0.00	0.0000		ENGR JUDGMT	0.00	#DIV/0!	0.00

NOTES:

ACTUAL 1994 EMISSIONS

1) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for actual VOC emissions. Actual plant data was used in the VOC calculations.
2) Actual 1995 HAPs emissions negligible.

POTENTIAL CONTROLLED EMISSIONS

3) The maximum potential throughput is based on the maximum (approximate) amount of fuel oil which could be burned by the combustion units.
4) The emissions factor is variable. See AP-42 Tanks 2.0 Emissions Report for potential VOC emissions. Actual plant data was used in the VOC calculations.
5) Potential 1995 HAPs emissions insignificant.

CONTROL EQUIPMENT AND ASSOCIATED EFFICIENCIES

6) There is no emissions control equipment.

ATTACHMENT 5

EMISSION CONTROL EQUIPMENT UPGRADE SUMMARY

The following is a brief summary of the emission Control Equipment upgrades completed or planned by D G & T for Bonanza 1.

1. Low NOx Burners:

During the May 1997 Outage, D G & T replaced all of its burners. The new Low NOx Burners have reduced actual NOx emissions the Bonanza 1.

2. Replacement Bags for the Baghouse:

The new fiberglass Bags are used to completely replace the existing filter bags. There are 450 Bags in each compartment, 24 compartments, for a total of 10,800 Bags.

3. Grasshopper Conveyors:

These portable conveyors will be used to move Sludge Landfill material from the Radial Stacker to the area being landfilled. This will reduce emissions by eliminating the need of heavy equipment hauling material from the Stacker to the landfill area.

4. New Bull Gear on the Ball Mill:

D G & T is replacing the Bull Gear with a redesigned model on a Ball Mill to improve efficiency of the Grinding unit.

5. New Absorber Inlet Damper Seals:

During the May 1997 Outage, D G & T upgraded the Absorber Inlet Damper seals. This new Seal design reduces the flow of untreated Flue Gas.

6. New Thickener Rake:

D G & T has ordered a new Sludge Thickener Rake. This new rake will improve the efficiency of the original equipment.

7. New Underflow Sludge Pump:

D G & T has installed a new Underflow Sludge pump to upgrade the operation of the Sludge system.

8. New Bulk Entrainment/Mist Eliminator Section (BE/MES) in all three Absorbers:

D G & T is in the process of upgrading all of its Absorber Modules. New design BE/MES are being installed. Carryover and Differential Pressure are reduced in each Absorber improving operational efficiency.

EXHIBIT B

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 15 1988

MEMORANDUM

SUBJECT: Procedures for EPA to Address Deficient New Source Permits Under the Clean Air Act

FROM: Michael S. Alushin
Associate Enforcement Counsel for Air Office of Enforcement and Compliance Monitoring

John S. Seitz, Director
Stationary Source Compliance Division
Office of Air Quality Planning and standards

TO: Addressees

INTRODUCTION

This memorandum transmits the final guidance for your use in addressing deficient new source permits. After we distributed the draft guidance for comment on December 16, 1987, several Regional Offices took action on deficient new source permits. The events surrounding those permit actions, as well as your thoughtful comments on the draft guidance, have shaped the final policy.

RESPONSE TO COMMENTS

We have incorporated most of your comments into the final guidance. As you requested, we have included examples of forms showing a request for permit review under 40 C.F.R. Section 124.19, a Section 167 order, and a Section 113(a) (5) finding of violation.

Some commenters suggested that we include a section on actions that can be taken, not against the source, but against the state issuing the deficient permit. We agree that this topic should be included in the guidance because it surfaces repeatedly in individual cases. Therefore, we have added a section on possible actions against states for issuing deficient permits. We have also clarified the guidance to indicate that EPA should send a state written comments at both the draft and final permit stage when a state is issuing what EPA considers a deficient permit.

Some reviewers requested further elaboration of when to use alternative enforcement responses. We have indicated relevant considerations in determining which action to take. One commenter pointed out that the guidance did not define what was meant by a "deficient permit." This involves a determination that requires the exercise of judgment. However, we have tried to list most of the criteria that will support a finding of deficiency. We realize, however, that we may not have anticipated every deficiency that may present itself to every Regional Office in the future.

Concern was expressed over the requirement to respond to a deficient permit within thirty days. We realize that this is an ambitious objective, but it is a legal requirement for permit review under 40 C.F.R Section 124, and greatly enhances EPA's equitable position in challenges under Section 167 and Section 113(a) (5). It will be easier to meet this deadline if Regional Offices have routine procedures in place for prompt receipt of all permits from their states and for thorough review of permits as they are received.

A few commenters wanted the guidance expanded to apply to "netting" actions and "synthetic minor" sources. We agree that guidance in this area would be useful, but the topic is too broad to be folded into the same document as the guidance on deficient permits. We have begun work to address appropriate enforcement action for improper "synthetic minors" in the context of the Federal Register notice announcing the program for federally enforceable state operating permits. If you think that separate enforcement guidance is needed on this subject, please let us know.

Finally a few reviewers questioned the guidance regarding EPA directly- issued permits. We agree that, in all cases where we find a deficiency, it is preferable to change the permit by modifying its terms. If the source is amenable, we should do so. However, if EPA cannot get the source to accept new permit conditions, our only options are review under Section 124.19(b), revocation of the permit, and/or enforcement action. A Section 124.19 (b) review must be taken within 30 days after the permit was issued. The

regulations are unclear on EPA's authority to revoke PSD permits. In an enforcement action to force a source, involuntarily, to accept a permit change when the source has not requested the change or made any modification to its facility or operations, EPA must always keep in mind the litigation practicalities and equities. These make enforcing against a permit we have issued when we are not basing our action on any new information a difficult proposition.

CONCLUSION

We hope that this guidance will help EPA Regions act to challenge deficient new source permits. Many of the practices advocated in this document may be litigated in pending or future cases. We will amend the guidance as necessary in light of judicial developments. If you have any questions, please contact attorney Judith Katz at FTS 382-2843.

Attachment

Addressees:

Regional Counsels
Regions I-X

Regional Counsel Air Branch Chiefs
Regionx I-X

Air and Waste Management Division Director
Region II

Air Management Division Directors
Regions I, III, and IX

Air and Radiation Division Director
Region V

Air, Pesticides, and Toxics Management Division Directors
Regions IV and VI

Air and Toxics Division Directors
Region VII, VII, VIII, and X

PSD Contracts
Regions I-X

Alan Eckert
Associate General Counsel

Greg Foote, OGC

Gary McCutchen
NPPB, AQMD (MD-15)

Ron McCallum
Chief Judicial Officer
EPA

David Buente, Chief
Environmental Enforcement Section
DOJ

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 15 1988

MEMORANDUM

SUBJECT: Procedures for EPA to Address Deficient New Source Permits Under the Clean Air Act

FROM: Michael S. Alushin
Associate Enforcement Counsel for Air Office of Enforcement and Compliance Monitoring

John S. Seitz, Director
Stationary Source Compliance Division
Office of Air Quality Planning and Standards

TO: Addressees

I. Introduction

This guidance applies to permits issued for major new sources and major modifications under both the prevention of significant deterioration (PSD) program and the nonattainment new source review (NSR) program. It contains three sets of procedures -- one for permits issued pursuant to EPA-approved state programs (NSR permits and PSD permits in more than half the states) one for permits issued by states pursuant to delegations of authority from EPA, and one for instances where EPA issues the permit directly. An appendix of model forms appears at the end.

The need for this guidance has become increasingly evident in the last two years. Before then, EPA had attempted only once, in 1981, to enforce against sources constructing or operating with new source permits the Agency determined to be deficient. In 1986, EPA litigated Greater Detroit Recovery Facility v. Adamkus et al. No. 86-CU-72910-DT (October 21, 1986). In that case, EPA wanted to enforce against a major stationary source constructing with a PSD permit issued by Michigan under a delegation agreement with EPA. The Agency had first determined that the best available control technology (BACT) determination for SO2 in the permit was inadequate. Before EPA started formal enforcement action, the source filed suit against the Agency,

arguing that EPA had no authority to "second guess" the BACT determination and that, in any event, we should be equitably foreclosed from challenging the permit because we had remained silent during the two years since we had failed to comment on the permit. The court agreed and granted the source's motion for summary judgement.

The Detroit case was an example of the need for prompt and thorough EPA review of and written comments on new source permits. Our ability to influence the terms of a permit, both informally and through legal procedures, diminishes markedly the longer EPA waits after a permit is issued before objecting to a specific term. This is due both to legal constraints, that is, tight time limits for comments provided in the regulations, and to equitable considerations that make courts less likely to require new sources to accept more stringent permit conditions the farther planning and construction have progressed. Accordingly, as a prerequisite to successful enforcement action, it is imperative that EPA review all major source permit packages on a timely basis and provide detailed comments on deficiencies. If EPA does not obtain adequate consideration of those comments, it is also important for EPA to protect air quality by prompt and consistent enforcement action against sources whose permits are found lacking. Because PSD permits are issued on a case-by-case basis, taking into consideration individual source factors, permitting decisions involve the exercise of judgment. However, although not an exhaustive list, any one of the following factors will normally be sufficient for EPA to find a permit "deficient" and consider enforcement action:

1. BACT determination not using the "top-down" approach.

2. BACT determination not based on a reasoned analysis.

3. No consideration of unregulated toxic pollutants in BACT determination.

4. Public notice problems - no public notice & comment period or deficiencies in the public notice.

5. Inadequate air quality modeling demonstrations.

6. Inadequate air quality analysis or impact analysis.

7. Unenforceable permit conditions.

8. For sources that impact Class I areas, inadequate notification of Federal Land Manager or inadequate consideration of impacts on air quality related values of Class I areas.

In NSR permitting, each of the following factors, while not necessarily an exhaustive list, are grounds for a deficient permit:

1. Incorrect LAER determination, i.e., failure to be at least as stringent as the most stringent level achieved in practice or required under any SIP or federally enforceable permit.

2. No finding of state-wide compliance.

3. No emissions offsets or incorrect offsets.

4. Public notice problems - no public notice and comment or deficiencies in public notice.

5. Unenforceable permit conditions.

II. Timing of EPA Response

A. Comment

Although EPA should know about every permit, at least by the time it is published as a proposal, the Agency sometimes does not learn about a permit during its development prior to the time the final permit is issued. If we do become aware of the permit and have objections to any of its terms, we should comment during the developmental stage before the permit becomes final.

State agencies should send copies of all draft permit public notice packages and all final permits to EPA immediately upon issuance. (The requirements for contents of public notice packages are set forth at 40 C.F.R. Section 51.166(q)(2](iii).) The Regional Office should review all draft permit public notice packages and final permits during the 30 day comment periods provided for in the federal regulations. It should write detailed comments whenever Agency staff does not agree with the terms of a draft or final permit. To make sure they get permits in time for review, Regional Offices should consider requiring states with approved new source programs, through Section 105 Grant Conditions, to notify them of the receipt of all major new source permit applications. They should also require states to send them copies of their draft permits at the beginning of the public comment period.

Final permits should be required to be sent to EPA immediately upon issuance. (Note that the requirement for Regions to review draft and final permits is contained in guidance issued by Craig Potter on December 1, 1987.) Regions should carefully check their agreements with delegated states. These agreements require

states to send draft permits to EPA during the comment period. In addition, 40 C.F.R. Section 52.21(u)(2)(ii) requires delegated agencies to send a copy of any public comment notice to the appropriate regional office. Pursuant to 40 C.F.R. Section 124.15, a final permit does not become effective until 30 days after issuance, unless there are no comments received during the comment period, in which case it becomes effective immediately. Regions should make sure that delegated states know about permit appeal procedures at 40 C.F.R. Section 124 and, if necessary, issue advisory memoranda notifying them that EPA will use these procedures if the Agency determines a permit is deficient.

B. Formal Enforcement Action

If the permit was issued under a delegated program, it is important to initiate formal review or appeal within 30 days after the final permit is issued. (This response is set forth in Section IV below. The 30 day period is required by the regulations at 40 C.F.R. Section 124.19). When enforcing against permits issued under state programs, the same legal requirement to initiate enforcement within 30 days does not exist, but it is still extremely important to act expeditiously.

III. Enforcement Against the Source v. Enforcement Against the State

If a state has demonstrated a pattern of repeatedly issuing deficient permits, EPA may consider revoking the delegation for a delegated state or acting under Section 113(a) (2) of the Act to assume federal enforcement for an approved state. It is not appropriate to issue a Section 167 order to a state. Revocations of delegated authority as to individual permits and revocations of actual permits are theoretically possible, but they are unnecessary where EPA can act under Part 124 (i.e. within 30 days of issuance). Revocation may be appropriate where Part 124 appeals are unavailable, but likely will be subject to legal challenge.

IV. Procedures to Follow When Enforcing Against Deficient Permits in Delegated Programs

A. If possible, the following actions before construction commences:

1. Take action under 40 C.F.R. Section 124.19(a) or (b) within 30 days of the date the final permit was issued to review deficient provisions of the permit.

    a. Section 124.19(a) is an appeal, which may be taken by any person who commented during the public comment period.

b. Section 124.19(b) is a review of the terms of the permit by the Administrator under his own initiative. Regional Offices informally request the Administrator to take this action. They need not have commented during the public comment period. The Administrator has demonstrated a preference for using Section 124.19(b) over Section 124.19(a). In the four instances thus far when he was given the choice of acting under (a) or (b), he chose (b). However, the Administrator may not have sufficient time to act within 30 days in every situation in the future.

2. In the majority of situations, it is more appropriate for the Agency to act as one body to initiate review under Section 124.19(b). In some instances, however, the third party role for a Regional Office, through 40 C.F.R. Section 124.19(a) may be preferable. Regions should pick (a) or (b). However, if both provisions are legally available, they should request, in the alternative, that the Administrator act under the provision other than the one chosen by the Region should he deem it more appropriate. In particular, if a Region requests the Administrator to act under Section 124.19(b), it should ask that its memorandum be considered as a petition for review under Section 124.19(a) should review under Section 124.19(b) not be granted within 30 days. This is to protect the Regions' right to appeal a permit if the Administrator does not have sufficient time to act. Therefore, all memoranda requesting review should be written to withstand public scrutiny if considered as petitions under Section 124.19(a).

3. If the 30 day period for appeal has run and strong equities in favor of enforcement exist, issue a Section 167 order and be prepared to file a civil action to prohibit commencement of construction until the source secures a valid permit. (See Section IV B(2)) below.

B. For sources where construction has already commenced:

1. If the permit was issued less than 30 days previously take action under 40 CFR Section 124.19.

2. If the permit was issued more than 30 days previously, issue a Section 167 order requiring immediate cessation of construction until a valid permit is obtained. This

step should only be taken if extremely strong equities in favor of enforcement exist. Regions should be keeping state and source informed of all informal efforts to change permit terms before the Section 167 order is issued. Section 167 orders may be used both for sources which have and have not commenced construction. However, because the Section 124.19 administrative appeal and review process is available in delegated programs, it is greatly preferred for challenging deficient permits in states where it can be used.

3. If EPA determines that penalties are appropriate, issue a NOV under Section 113(a) (1) of the Act for commencement of construction of a major source or major modification without a valid permit. This is necessary because Section 167 contains no penalty authority. Note that strong equities for enforcement must exist before taking this step. EPA can issue both a Section 167 order requiring immediate injunctive relief and a NOV if we decide that both are appropriate.

4. Follow up with judicial action under Section 167 and Section 113(b) (2) if construction continues without a new permit.

C. Note that the appeal provisions of 40 C.F.R. Section 124.19 apply to all delegated PSD programs even if Section 124.19 is not specifically referenced in the delegation.

V. Procedures to Follow When Enforcing Against Permits in EPA-Approved State Programs (All NSR and More Than Half of the PSD Programs)

A. Issue Section 113(a) (5) order (for NSR) or 167 order (for PSD) as expeditiously as possible, preferably within 30 days after the permit is issued, requiring the source not to commence construction, or if already started, to cease construction (on the basis that it would be constructing with an invalid permit), and to apply for a new permit. Note that EPA should issue a Section 167 order if it has determined that there is a reasonable chance the source will comply. Otherwise, the Region should move directly to section V.D below.

B. From the outset of EPA's involvement, keep the source informed of all EPA's attempts to convince the permitting agency to change the permit.

C. Issue an NOV (113(a)) as soon as construction commences if EPA determines penalties are appropriate.

D. If source does not comply with order, follow up with judicial action under Section 167, Section 113(b) (5), or, if NOV issued, Section 113(b) (2). If penalties are appropriate, issue NOV and later amend complaint to add a Section 113 count when 30 day statutory waiting period has run after initial action is filed under Section 167.

VI. For EPA-issued Permits (Non-delegated)

A. If source submitted inadequate information (e.g., misleading, not identifying all options) and EPA recently found out about it,

1. If within 30 days of permit issuance, request review by the Administrator under 40 C.F.R. Section 124.19(b).

2. If permit has been issued for more than 30 days, issue Section 167 or Section 113(a) (5) order preventing startup or, if appropriate, immediate cessation of construction.

3. Issue NOV if construction has commenced and EPA determines penalties to be appropriate.

4. If necessary, request additional information from source; if source cooperates, issue new permit.

5. Consider taking judicial action if appropriate.

EPA recognizes the distinction between permits based on faulty and correct information only for EPA directly-issued permits. This distinction is necessary for EPA permits due to equitable considerations.

B. If source submitted adequate information and EPA issued faulty permit, we should attempt to get source to agree to necessary changes and accept modification of its permit. However, if source will not agree, only available options are revoking the permit and enforcing. Consolidated permit regulations are unclear about EPA's authority to revoke PSD permits. Because of this and the equitable problems associated with enforcing against our own permits, unless new information about health effects or other significant findings is available, we may choose to accept the permit. If faulty permit produces unacceptable environmental risk, act under 40 C.F.R. Section 124.19, if possible. If action under 40 C.F.R. Section 124.19 not possible, first revoke permit and then act as set forth in Section IV.

Addressees:

Regional Counsels
Regions I-X

Regional Counsel Air Contacts
Regions I-X

Air and Waste Management Division Director
Region II

Air Management Division Directors
Regions I, III, and IX

Air and Radiation Division Director
Region V

Air, Pesticides, and Toxics Management Division Directors
Regions IV and VI

Air and Toxics Division Directors
Regions VII, VIII, and X

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NPPB, AQMD (MD-15)

Ron McCallum
Chief Judicial Officer

Bob Van Heuvelen
Environmental Enforcement Section
Department of Justice

David Buente, Chief
Environmental Enforcement Section
Department of Justice

Appendix

1. Request for Review under 40 C.F.R. Section 124.19

2. Section 167 Order

3. Section 113(a)(5) finding of violation and accompanying Section 113(a) (1) Notice of violation

EXHIBIT C

BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY

IN THE MATTER OF SCHERER STEAM-ELECTRIC GENERATING PLANT JULIETTE, GEORGIA PERMIT NO. 4911-207-0008-V-03-0 HAMMOND STEAM-ELECTRIC GENERATING PLANT COOSA, GEORGIA PERMIT NO. 4911-115-0003-V-03-0 WANSLEY STEAM-ELECTRIC GENERATING PLANT CARROLLTON, GEORGIA PERMIT NO. 4911-149-0001-V-03-0 KRAFT STEAM-ELECTRIC GENERATING PLANT PORT WENTWORTH, GEORGIA PERMIT NO. 4911-051-0006-V-03-0 MCINTOSH STEAM-ELECTRIC GENERATING PLANT RINCON, GEORGIA PERMIT NO. 4911-103-0003-V-03-0 ISSUED BY THE GEORGIA ENVIRONMENTAL PROTECTION DIVISION	ORDER RESPONDING TO PETITIONERS' REQUESTS THAT THE ADMINISTRATOR OBJECT TO ISSUANCE OF STATE OPERATING PERMITS PETITION NOS. IV-2012-1, IV-2012-2 IV-2012-3, IV-2012-4 AND IV-2012-5

ORDER GRANTING IN PART AND DENYING IN PART FIVE PETITIONS FOR OBJECTION TO PERMITS

I. INTRODUCTION

This Order responds to issues raised in five related petitions submitted to the U.S. Environmental Protection Agency by GreenLaw on behalf of the Sierra Club and several other environmental organizations[1] (the Petitioners) pursuant to Section 505(b)(2) of the Clean Air Act ("CAA" or "Act"), 42 United States Code (U.S.C.) § 7661d(b)(2). The petitions seek the EPA's objection to operating permits issued by the Georgia Environmental Protection Division (Georgia EPD) to Georgia Power/Southern Company for five existing coal-fired electricity and steam generating plants located in the state of Georgia. Petition IV-2012-1, received on June 13, 2012, addresses the operating permit for the Scherer Steam-Electric Generating Plant (Plant Scherer). Petition IV-2012-2, received by the EPA on June 15, 2012, addresses the operating permit for the Hammond Steam-Electric Generating Plant (Plant

[1] Southern Alliance for Clean Energy, Fall-line Alliance for a Clean Environment, and Ogeechee Riverkeeper joined the Sierra Club in the Plant Wansley Petition (Petition No. IV-2012-3). Southern Alliance for Clean Energy also joined Sierra Club in the Plant Kraft Petition (Petition No. IV-2012-4).

Hammond). Petition IV-2012-3, received on September 5, 2012, addresses the operating permit for Wansley Steam-Electric Generating Plant (Plant Wansley). Petition IV-2012-4, received on October 23, 2012, addresses the operating permit for Kraft Steam-Electric Generating Plant (Plant Kraft). Finally, Petition IV-2012-5, received on November 13, 2012, addresses the operating permit for McIntosh Steam-Electric Generating Plant (Plant McIntosh). These permits are state operating permits issued by Georgia EPD pursuant to title V of the CAA, CAA §§ 501-507, 42 U.S.C. §§ 7661-7661f, the EPA's implementing regulations at 40 Code of Federal Regulations (C.F.R.) Part 70, and Georgia's EPA-approved state operating program regulations at Georgia Air Quality Rule 391-3-1-.03(10). The Petitioners timely filed all five petitions within 60 days after the expiration of the relevant EPA review period for each permit, consistent with CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2). Due to significant overlap in the issues raised in the Petitions and the similarity of the relevant permit conditions in each of the five permits, the EPA is responding to all five petitions in this Order.

The Petitioners requested that the EPA object to the five Georgia Power title V permits on several different grounds. The Petitioners did not raise all of their claims in every Petition. In total, the Petitioners raise five claims, which are described in detail in Section IV of this Order, below. In summary, the issues raised are:

(1) The permits lack sufficiently detailed information regarding the facilities' compliance obligations related to hazardous air pollutant (HAP) emissions under the National Emission Standards for Hazardous Air Pollutants (NESHAP) for electric utility steam generating units at 40 C.F.R. 63 Subpart UUUUU. (Raised in the petitions on Plants Hammond, Kraft, McIntosh, Wansley and Scherer).
(2) The permits do not assure compliance at all times with the sulfur dioxide (SO_2) emission limit derived from Georgia Rule 391-3-1-.02(2)(uuu) because they appear to authorize the facilities to not operate their continuous emissions monitoring system (CEMS) for SO_2 during startup, shutdown, malfunction and other periods. (Raised in the petitions on Plants Hammond, Wansley and Scherer).
(3) The permits' particulate matter (PM) monitoring requirements are insufficient to assure compliance with PM emission limits. (Raised in the petitions on Plants Hammond, McIntosh, Wansley and Scherer).
(4) The permit conditions governing fugitive dust control do not comply with the state implementation plan (SIP), do not assure compliance with the applicable 20 percent opacity standard, and are vague and unenforceable. (Raised in the petitions on Plants Hammond, Kraft, McIntosh, Wansley and Scherer).
(5) The permit for Plant Scherer should include preconstruction requirements under the CAA's Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) programs due to recent and planned upgrades to the facility's steam turbines. (Raised in the petition on Plant Scherer).

For the reasons provided below, based on a review of the Petitions and other relevant materials, including the permits, permit records, and applicable statutory and regulatory authorities, I grant in part and deny in part the five petitions requesting that the EPA object to the five Georgia Power permits. Specifically, as explained in Section IV.D of this order, I grant the five petitions on Claim 4, regarding permit conditions governing fugitive dust, which the Petitioners raised with respect to all five permits. In addition, as described in the EPA's response to Claim 2 in Section IV of this Order, I am also notifying the state and the permittees of the EPA's determination that cause exists to reopen the Hammond, Scherer and Wansley permits, pursuant to 42 U.S.C. § 7661d(e) and 40 C.F.R. § 70.7(g).

II. STATUTORY AND REGULATORY FRAMEWORK

Section 502(d)(l) of the CAA, 42 U.S.C. § 766la(d)(l), requires each state to develop and submit to the EPA an operating permit program to meet the requirements of title V of the CAA. The EPA granted interim approval of Georgia's title V operating permit program on November 22, 1995 (60 *Fed. Reg.* 57836) and full approval on June 8, 2000 (65 *Fed. Reg.* 36358). 40 C.F.R. Part 70, Appendix A. This program is codified in Georgia Air Quality Rule 391-3-1-.03(10).

All major stationary sources of air pollution and certain other sources are required to apply for title V operating permits that include emission limitations and other conditions as necessary to assure compliance with applicable requirements of the CAA, including the requirements of the applicable SIP. CAA §§ 502(a) and 504(a), 42 U.S.C. §§ 7661a(a) and 7661c(a). The title V operating permit program generally does not impose new substantive air quality control requirements, but does require permits to contain adequate monitoring, recordkeeping, reporting and other requirements to assure sources' compliance with applicable requirements. 57 *Fed. Reg.* 32250, 32251 (July 21, 1992). One purpose of the title V program is to "enable the source, States, the EPA, and the public to understand better the requirements to which the source is subject, and whether the source is meeting those requirements." *Id.* Thus, the title V operating permit program is a vehicle for ensuring that air quality control requirements are appropriately applied to facility emission units and for assuring compliance with such requirements.

Applicable requirements for a new major stationary source or for a major modification to a major stationary source include the requirement to obtain a preconstruction permit that complies with applicable new source review (NSR) requirements. For major sources, the NSR program is comprised of two core types of preconstruction permit programs. Part C of Title I of the CAA establishes the PSD program, which applies to areas of the country that are designated as attainment or unclassifiable for the national ambient air quality-standards (NAAQS). CAA §§ 160-169, 42 U.S.C. §§ 7470-7479. Part D of Title I of the Act establishes the NNSR program, which applies to areas that are designated as nonattainment with the NAAQS. The EPA has two largely identical sets of regulations implementing the PSD program, one set, found at 40 C.F.R. § 51.166, contains the requirements that state PSD programs must meet to be approved as part of a SIP. The other set of regulations, found at 40 C.F.R. § 52.21, contains the EPA's federal PSD program, which applies in areas without a SIP-approved PSD program. The EPA has approved Georgia's PSD SIP, which is codified in Georgia Rule 391-3-1-.02(7). *See* 40 C.F.R. § 52.570(b). The EPA's regulations implementing the NNSR program are codified at 40 C.F.R. §§ 51.160-51.165, and Georgia's SIP-approved NNSR regulations are codified at Georgia Rule 391-3-1-.03(8). *See* 40 C.F.R. § 52.570(b). The applicable requirements of the Act for new major sources or major modifications include the requirement to comply with PSD and NNSR requirements. *See, e.g.,* 40 C.F.R. § 70.2.[2] At issue in this order, among other things, is whether Plant Scherer's Turbine Upgrade Project qualified as a "major modification" that should have been subject to PSD and NNSR requirements.

[2] Under 40 C.F.R. § 70.1(b), "[a]ll sources subject to [the title V regulations] shall have a permit to operate that assures compliance by the source with all applicable requirements." "Applicable requirements" are defined in 40 C.F.R. § 70.2 to include "(1) [a]ny standard or other requirement provided for in the applicable implementation plan approved or promulgated by EPA through rulemaking under title I of the [Clean Air] Act that implements the relevant requirements of the Act, including any revisions to that plan promulgated in [40 C.F.R.] part 52; (2) [a]ny term or condition of any preconstruction permits issued pursuant to regulations approved or promulgated through rulemaking under title I, including parts C or D, of the Act."

A. Review of Issues in a Petition

State and local permitting authorities issue title V permits pursuant to the EPA-approved title V programs. Under CAA § 505(a), 42 U.S.C. § 766ld(a), and the relevant implementing regulations found at 40 C.F.R. § 70.8(a), states are required to submit each proposed title V operating permit to the EPA for review. Upon receipt of a proposed permit, the EPA has 45 days to object to final issuance of the permit if the EPA determines that the permit is not in compliance with applicable requirements of the Act. CAA §§ 505(b)(1), 42 U.S.C. § 7661d(b)(1); *see also* 40 C.F.R. § 70.8(c) (providing that the EPA will object if the EPA determines that a permit is not in compliance with applicable requirements or requirements under 40 C.F.R. Part 70). If the EPA does not object to a permit on its own initiative, § 505(b)(2) of the Act and 40 C.F.R. § 70.8(d), provide that any person may petition the Administrator, within 60 days of the expiration of the EPA's 45-day review period, to object to the permit. The petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period). CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(d). In response to such a petition, the Act requires the Administrator to issue an objection if a petitioner demonstrates to the Administrator that a permit is not in compliance with the requirements of the Act. CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2); 40 C.F.R. § 70.8(c)(1); *see also New York Public Interest Research Group, Inc. (NYPIRG) v. Whitman,* 321 F.3d 316, 333 n.11 (2nd Cir. 2003). Under § 505(b)(2) of the Act, the burden is on the petitioner to make the required demonstration to the EPA. *MacClarence v. EPA,* 596 F.3d 1123, 1130-33 (9th Cir. 2010); *Sierra Club v. Johnson,* 541 F.3d 1257, 1266-1267 (11th Cir. 2008); *Citizens Against Ruining the Environment v. EPA,* 535 F.3d 670, 677-78 (7th Cir. 2008); *WildEarth Guardians v. EPA*, 728 F.3d 1075, 1081-1082 (10th Cir. 2013); *Sierra Club v. EPA,* 557 F.3d 401, 406 (6th Cir. 2009) (discussing the burden of proof in title V petitions); *see also NYPIRG,* 321 F.3d at 333 n.11. In evaluating a petitioner's claims, the EPA considers, as appropriate, the adequacy of the permitting authority's rationale in the permitting record, including the response to comments (RTC), among other things.

The petitioner's demonstration burden is a critical component of CAA § 505(b)(2). As courts have recognized, CAA § 505(b)(2) contains both a "discretionary component," to determine whether a petition demonstrates to the Administrator that a permit is not in compliance with the requirements of the Act, and a nondiscretionary duty to object where such a demonstration is made. *NYPIRG*, 321 F.3d at 333; *Sierra Club v. Johnson*, 541 F.3d at 1265-66 ("it is undeniable [CAA § 505(b)(2)] also contains a discretionary component: it requires the Administrator to make a judgment of whether a petition demonstrates a permit does not comply with clean air requirements"). Courts have also made clear that the Administrator is only obligated to grant a petition to object under CAA § 505(b)(2) if the Administrator determines that the petitioners have demonstrated that the permit is not in compliance with requirements of the Act. *See, e.g., Citizens Against Ruining the Environment*, 535 F.3d at 667 (§ 505(b)(2) "clearly obligates the Administrator to (1) determine whether the petition demonstrates noncompliance and (2) object <u>if</u> such a demonstration is made") (emphasis added); *NYPIRG*, 321 F.3d at 334 ("§ 505(b)[2] of the CAA provides a step-by-step procedure by which objections to draft permits may be raised and directs the EPA to grant or deny them, *depending on* whether non-compliance has been demonstrated.") (emphasis added); *Sierra Club v. Johnson*, 541 F.3d at 1265 ("Congress's use of the word 'shall' ... plainly mandates an objection *whenever* a petitioner demonstrates noncompliance") (emphasis added). When courts review the EPA's interpretation of the ambiguous term "demonstrates" and its determination as to whether the demonstration has been made, they have applied a deferential

standard of review. *See, e.g., Sierra Club v. Johnson*, 541 F.3d at 1265-66; *Citizens Against Ruining the Environment*, 535 F.3d at 678; *MacClarence*, 596 F.3d at 1130-31. This order addresses certain aspects of the petitioner demonstration burden below; however, a fuller discussion can be found in *In the Matter of Consolidated Environmental Management, Inc. – Nucor Steel Louisiana*, Order on Petition Numbers VI-2011-06 and VI-2012-07 (June 19, 2013) (*Nucor II Order*) at 4-7.

The EPA examines a number of criteria in determining whether a petitioner has demonstrated noncompliance with the Act. *See generally Nucor II Order* at 7. For example, one such criterion is whether the petitioner has addressed the state or local permitting authority's decision and reasoning. The EPA expects the petitioner to address the permitting authority's decision, and reasoning (including the RTC, where available). *See MacClarence*, 596 F.3d at 1132-33; *see also, e.g., In the Matter of Noranda Alumina, LLC*, Order on Petition No. VI-2011-04 (December 14, 2012) (*Noranda Order*) at 20 (denying title V petition issue where petitioners did not respond to state's explanation in response to comments or explain why the state erred or the permit was deficient); *In the Matter of Kentucky Syngas, LLC*, Order on Petition No. IV-2010-9 (June 22, 2012) at 41 (*2012 Kentucky Syngas Order*) (denying title V petition issue where petitioners did not acknowledge or reply to state's response to comments or provide a particularized rationale for why the state erred or the permit was deficient). Another factor the EPA examines is whether the petitioner has provided the relevant analyses and citations to support its claims. If the petitioner does not, the EPA is left to work out the basis for petitioner's objection, contrary to Congress' express allocation of the burden of demonstration to the petitioner in CAA § 505(b)(2). *See MacClarence*, 596 F.3d at 1131 ("the Administrator's requirement that [a title V petitioner] support his allegations with legal reasoning, evidence, and references is reasonable and persuasive"); *In the Matter of Murphy Oil USA, Inc.*, Order on Petition No. VI-2011-02 (Sept. 21, 2011) (hereafter "*Murphy Oil Order*") at 12 (denying a title V petition claim where the petitioner claimed that the permit lacked sufficient monitoring, but failed to identify any permit term or condition for which monitoring was lacking). Relatedly, the EPA has pointed out in numerous orders that, in particular cases, general assertions or allegations did not meet the demonstration standard. *See, e.g., In the Matter of Luminant Generation Co. – Sandow 5 Generating Plant*, Order on Petition Number VI-2011-05 (Jan. 15, 2013) at 9; *In the Matter of BP Exploration (Alaska) Inc., Gathering Center #1*, Order on Petition Number VII-2004-02 (Apr. 20, 2007) at 8; *In the Matter of Chevron Products Co., Richmond, Calif. Facility*, Order on Petition No. IX-2004-10 (Mar. 15, 2005) (hereafter "*Chevron Order*") at 12, 24. Also, if the petitioner fails to address a key element of a particular issue, the EPA has denied the petition. *See, e.g., In the Matter of Public Service Company of Colorado, dba Xcel Energy, Pawnee Station,* Order on Petition Number: VIII-2010-XX (June 30, 2011) at 7–10; *See, e.g., In the Matter of Georgia Pacific Consumer Products LP Plant,* Order on Petition No. V-2011-1 at 6-7, 10-11 (July 23, 2012) at 10–11, 13–14.

B. Raising NSR Issues in a Petition

Where a petitioner's request that the Administrator object to the issuance of a title V permit is based in whole, or in part, on a permitting authority's alleged failure to comply with the requirements of its approved PSD or NNSR program (as with other allegations of inconsistency with the Act), the burden is on the petitioners to demonstrate to the Administrator that the permitting decision was not in compliance with the requirements of the Act, including the requirements of the SIP. Such requirements, as the EPA has explained in describing its authority to oversee the implementation of the PSD program in states with approved programs, include the requirements that the permitting authority, if applicable: (1) follow the required procedures in the SIP; (2) make PSD determinations on reasonable grounds properly supported on the record; and (3) describe the determinations in enforceable terms. *See, e.g., In the*

Matter of Wisconsin Power and Light, Columbia Generating Station, Order on Petition No. V-2008-01 (October 8, 2009) (*Columbia Generating Order*) at 8.[3]

Georgia EPD has substantial discretion in carrying out its responsibilities under Georgia's SIP-approved PSD and NNSR programs. Given this discretion, in reviewing a PSD or NNSR permitting decision, the EPA will not substitute its own judgment for that of Georgia. Rather, consistent with the decision in *Alaska Dep't of Envt'l Conservation v. EPA*, 540 U.S. 461 (2004), in reviewing a petition to object to a title V permit raising concerns regarding a state's PSD or NNSR permitting decision, the EPA generally will look to see whether the petitioner has shown that the state did not comply with its SIP-approved regulations governing PSD permitting or whether the state's exercise of discretion under such regulations was unreasonable or arbitrary. *See, e.g., In re Louisville Gas and Electric Company*, Order on Petition No. IV-2008-3 (Aug. 12, 2009) (hereafter "*LG&E Order*"); *In re East Kentucky Power Cooperative, Inc. Hugh L. Spurlock Generating Station*, Order on Petition No. IV-2006-4 (Aug. 30, 2007) (hereafter "*Spurlock Order*"); *In re Pacific Coast Building Products, Inc.* (Order on Petition) (Dec. 10, 1999); *In re Roosevelt Regional Landfill Regional Disposal Company* (Order on Petition) (May 4, 1999).

III. BACKGROUND

Plant Hammond is located in northwest Georgia near Coosa in Floyd County. The facility, which commenced operation in June 1954, currently consists of four wall-fired steam generating units (designated as Units SG01 through 04) with maximum heat input capacities ranging from 1,313 to 5,972 million British thermal units per hour (MMBtu/hr). Bituminous coal is the primary fuel for these units with limited use of wood, biomass, and #2 fuel oil. Also present are associated coal, ash and materials handling systems. Add-on controls include a flue gas desulfurization (FGD) scrubber system and electrostatic precipitators (ESPs) on Units SG01 through 04 and a selective catalytic reduction (SCR) scrubber on Unit SG04. The initial title V permit (#4911-115-0003-V-01-0) was issued January 1, 2000; the renewal permit (#4911-115-0003-V-03-0), on which the petition is based, was issued May 8, 2012.

Plant Kraft is located in north coastal Georgia near Port Wentworth in Chatham County. The facility, which commenced operation in 1958, currently consists of one wall-fired steam generating unit (Unit SG04)and three tangentially-fired steam generating units (Units SG01 through 03 and SG04) with maximum heat input capacities ranging from 647 to 1,493 MMBtu/hr. Bituminous coal is the primary fuel for Units SG01 through 03 with natural gas as backup. Natural gas is the primary fuel for Unit SG04 with #6 fuel oil as backup. Also present are: a simple cycle combustion turbine rated at 17 megawatts (MW) using natural gas as primary fuel with #2 fuel oil as backup, associated coal and ash handling systems, and a barge-to-railcar unloading system (for transport of coal to other facilities). Add-on controls include ESPs on Units SG01 through 03 and a dust control system on the barge-to-railcar transfer system. The initial title V permit (#4911-015-0006-V-01-0) was issued November 9, 1999; the renewal permit (#4911-015-0006-V-03-0), on which the petition is based, was issued September 24, 2012.

[3] In reviewing PSD permit determinations in the context of a petition to object to a title V permit, the standard of review applied by the Environmental Appeals Board (EAB) in reviewing the appeals of federal PSD permits provides a useful analogy. *In the Matter of Louisville Gas and Electric Company*, Order on Petition No. IV-2008-3 (Aug. 12, 2009) at 5 n.6; *see also In the Matter of East Kentucky Power Cooperative, Inc., Hugh L. Spurlock Generating Station*, Order on Petition No. IV-2006-4 (Aug. 30, 2007) at 5. The standard of review applied by the EAB in its review of federal PSD permits is discussed in numerous EAB orders as the "clearly erroneous" standard. *See, e.g., In re Prairie State Generation Company*, 13 E.A.D. 1, 10 (EAB, Aug. 24, 2006) (*Prairie State*); *In re Kawaihae Cogeneration*, 7 E.A.D. 107, 114 (EAB, April 28, 1997). In short, in such appeals, the EAB has explained that the burden is on a petitioner to demonstrate that review is warranted.

Plant McIntosh is located in east Georgia near Rincon in Effingham County. The facility, which commenced operation in 1979, currently consists of one wall-fired steam generating unit (designated as Unit SG01) with a maximum heat input of 1,862 MMBtu/hr. Bituminous coal is the primary fuel with limited use of wood, biomass and #2 fuel oil. Also present are: eight simple cycle combustion turbines rated at 103.5 MW each using natural gas as the primary fuel with #2 fuel oil, biodiesel and biodiesel blends as backup; one startup boiler; and associated coal and ash handling systems. Add-on controls include an ESP on SG01. The initial title V permit (#4911-103-0003-V-01-0) was issued November 9, 1999; the renewal permit (#4911-103-0003-V-03-0), on which the petition is based, was issued September 25, 2012.

Plant Scherer is located in middle Georgia near Juliette in Monroe County. The facility, which commenced operation in March 1982, currently consists of four tangentially-fired steam generating units (designated as Units SG01 through 04). Georgia Power is in the process of upgrading its four steam turbines and installing pollution control equipment; following completion of all steam turbine upgrades the maximum heat input capacities for the generating units will range from 9,653 to a projected 10,070 MMBtu/hr. Bituminous coal is the primary fuel with limited use of wood and #2 fuel oil. Also present are: two startup boilers and associated coal, ash and materials handling systems. Add-on controls include (or will include) FGD and SCR scrubber systems, ESPs and baghouses on Units SG01 through 04; wet suppression system on the coal handling system; and baghouses on the limestone silos of the materials handling system. The initial title V permit (#4911-207-0008-V-01-0) was issued January 1, 2000; the renewal permit (#4911-207-0008-V-03-0), on which the petition is based, was issued May 8, 2012.

Plant Scherer's title V permit was revised to address the recent steam turbine upgrades: the Unit SG03 steam turbine upgrade was addressed in permit revision #4911-207-0008-V-02-7, issued on November 16, 2009; the Unit SG01, 02 and 04 steam turbine upgrades were addressed in permit revision #4911-207-0008-V-02-A issued on February 23, 2010. According to the permit record, the purpose of the turbine upgrades is two-fold: (1) to improve the efficiency of the high-pressure section of the turbine, *i.e.*, the turbine will be able to generate more electricity from a unit of coal; and (2) to increase the maximum steam flow capacity (and, thus, increase heat input capacity) of the turbine, *i.e.*, the turbine will be able to generate more electricity due to increased capacity to burn coal.[4] This combined effect is to increase the maximum generating capacity of Scherer by 140 MW (or 35 MW from each turbine).[5] According to the respective statements of basis for the relevant permit revisions, the turbine upgrades were not projected to result in a significant emissions increase and, therefore, did not trigger PSD or NNSR review. The planned timing of the turbine upgrades was as follows: October 2010 for Unit SG03, January 2012 for Unit SG04, April 2013 for Unit SG02 and October 2013 for Unit SG01.

Concurrent with the steam turbine upgrades and as part of the same project, *i.e.*, during the same shutdown period for each electric utility steam generating unit (boiler/turbine or EUSGU)[6], Georgia Power received authorization from Georgia EPD to install pollution controls (FGDs and SCRs) on Units SG01 through 04 to comply with Georgia Rule 391-3-1-.02(2)(sss). Georgia EPD addressed Georgia

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[4] *See, e.g.*, Georgia Power's SIP Air Permit Application #18-835 for Unit SG03, dated March 10, 2009, at 4 (Plant Scherer Petition Exhibit E).

[5] *Id.*

[6] "Electric utility steam generating unit" means any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW electrical output to any utility power distribution system for sale. Any steam supplied to a steam distribution system for the purpose of providing steam to a steam-electric generator that would produce electrical energy for sale is also considered in determining the electrical energy output capacity of the affected facility. *See* 40 C.F.R. § 52.21(b)(31) and Georgia Rule 391-3-1.02(7)(a)2.(i), which in this case are identical.

Power's request to install the pollution controls in a significant modification to their title V permit issued on May 12, 2010 (#4911-207-0008-V-02-B).[7] The controls will be installed and operating when the source resumes regular operation after the project's completion.[8]

Plant Wansley is located in west Georgia near Carrollton in Heard County. The facility, which commenced operation in December 1976, currently consists of two tangentially-fired steam generating units (designated as Units SG01 and 02) with maximum heat input capacities of 9,420 MMBtu/her each. Bituminous coal is the primary fuel with limited use of wood, biomass, biodiesel, biodiesel blends and #2 fuel oil. Also present are: a simple cycle combustion turbine rated at 54 MW using #2 fuel oil, biodiesel and biodiesel blends; two startup boilers; and associated coal, ash and materials handling systems. Add-on controls include FGD and SCR scrubber systems and ESPs on Units SG01 and 02. The initial title V permit (#4911-149-0001-V-01-0) was issued January 1, 2000; the renewal permit (#4911-149-0001-V-03-0), on which the petition is based, was issued July 26, 2012.

IV. ISSUES RAISED BY THE PETITIONERS AND THE EPA'S RESPONSES[9]

Claim 1: Petitioners' Claim that the Permits Should Include Detailed Requirements for Hazardous Air Pollutant ("HAP") Standards.

Petitioners' Claim.[10] In their petitions of the permits for Plants Hammond, Kraft, McIntosh, Wansley and Scherer, the Petitioners claim that the permits are deficient because they lack sufficient detail regarding the facilities' obligation to control hazardous air pollutants under the NESHAP applicable to coal- and oil-fired electric utility steam generating units, which the Petitioners refer to as the "EGU MACT." The Petitioners observe that each of the five permits includes a condition that "makes a generic reference to the EGU MACT." The Petitioners note that this condition was not included in two of the permits when they were released for public comment, but that Georgia EPD added the condition to those two permits. The Petitioners assert that this generic condition is insufficient. Specifically, the Petitioners contend that all five permits are deficient because they do not include "the specific requirements of the

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[7] The narrative accompanying the permit revision addressing the turbine upgrades for Units SG01, SG0, and SG04 explained: "A flue gas desulfurization (scrubber) system and a selective catalytic reduction (SCR) system will be installed simultaneously with the project as required in accordance with Georgia Rule (sss)." Narrative, Permit Amendment #4911-207-0008-V-02-A, at 3. *See also* Narrative, Permit Amendment #4911-207-0008-V-7, at 3 (stating the same with respect to the relationship between the turbine upgrade for Unit SG03 and the installation of controls required by Georgia Rule (sss)).

[8] The footnotes for the "projected actual emissions" table in the narrative accompanying the permit revision addressing the turbine upgrades for Units SG01, SG02, and SG04 indicate that the emissions projections included consideration of the effect of controls. *See* Narrative, Permit Amendment #4911-207-0008-V-02-A, at 6. While the narrative accompanying the permit revision for Unit SG03 does not include the footnotes cited above, the EPA concludes the "projected actual emissions" for Unit SG03 also include operation of the controls for this unit, since the permit narrative describe identical controls (scrubber and SCR) installed simultaneously to the turbine upgrade projects to comply with the same requirements (Rule sss) at Unit SG01, Unit SG02 and Unit SG04. Narrative, Permit Amendment #4911-207-0008-V-02-7, at 3. Additionally, the associated permit application for the upgrade to Unit SG03 explained: "Actual emissions estimates based on ozone season only operation of the SCR...". Finally, Permit Condition 6.2.21 specifies for all four units that the Permittee must calculate and maintain a record of annual emissions for a period of ten years "following resumption of regular operations after installation of the upgraded high pressure steam turbines, and control equipment for each unit." (emphasis added). Therefore, for all four units, it is clear that the applicant and Georgia EPD envisioned that the controls would be installed and operating when the units resumed regular operations following completion of the Turbine Upgrade Project.

[9] Headings summarizing Petitioners' claims are taken verbatim from the Petition.

[10] Petitioners' claims regarding the inadequacy of the permits with respect to HAP standards appear in the Plant Hammond Petition at 10-11, the Plant Kraft Petition at 3-4, the Plant McIntosh Petition at 8-9, the Plant Wansley Petition at 11-12, and the Plant Scherer Petition at 19.

EGU MACT" and also do not include "provisions to add any additional monitoring required by 40 C.F.R. § 70.6(c)(1)."

EPA's Response. For the reasons provided below, I deny the Petitioners' request for an objection to the permits on this claim. The Petitioners did not demonstrate that the permits lack sufficient specificity regarding applicable EGU NESHAP requirements and associated monitoring.

The EGU NESHAP, published at 40 C.F.R. 63 Subpart UUUUU, was promulgated on February 16, 2012 and became effective on April 16, 2012. 77 *Fed. Reg.* 9304. The date by which sources must be in compliance is April 16, 2015, 40 C.F.R. § 63.9984(b), unless the source seeks and is granted a one year extension, 40 C.F.R. 63.6(i). The EGU NESHAP establishes numerical emission limits and allows facilities to select from a range of widely available and economically feasible technologies, practices and compliance strategies to meet these limits. The rule also provides an alternative compliance option for sources that plan to comply by averaging across multiple units.

Georgia EPD issued all five of the title V permits addressed by the Petitions more than two years prior to the EGU NESHAP compliance date.[11] Each of the five permits includes the following condition (or the equivalent) with respect to the EGU NESHAP:

> The Permittee shall comply with all applicable provisions of the "National Emission Standards for Hazardous Air Pollutants" as found in 40 CFR Subpart A, "General Provisions" and 40 CFR 63, Subpart UUUUU, "National Emission Standards for Hazardous Air Pollutants from Coal and Oil-Fired Electric Utility Steam Generating Units" for operation of steam generating units.
> [40 CFR 63, Subparts A and UUUUU][12]

Absent a specific requirement in the applicable NESHAP, a source is not required to have determined which of the available compliance approaches it will use to comply with the rule prior to the compliance date. The Petitioners have not identified any provision of the EGU MACT that requires such action. Selection of the particular compliance options for an affected source from among the available options in a NESHAP can be a complex determination.[13] Thus, when a permit is issued prior to the NESHAP compliance date, a source may not have yet determined the provisions that will describe NESHAP applicability beyond the subpart level. EPA has previously stated that:

> When a permit is issued prior to the MACT compliance date, the EPA believes that it is acceptable for the initial permit to describe MACT applicability at the Subpart level, and for all other compliance requirements (including compliance options and parameter ranges) of the MACT that apply below the Subpart level to be added at a later time as a significant permit modification.

In re ConocoPhillips Company, Order on Petition, Petition No. IX-2004-09 (March 15, 2005), at 24-25; see also *In re Chevron Products Company*, Order on Petition, Petition No. IX-2004-08 (March 15, 2005), at 39; Letter from John Seitz, EPA, to Robert Hodanbosi, STAPPA/ALAPCO (May 20, 1999),

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[11] Georgia EPD issued the Plants Scherer and Hammond permits on May 8, 2012, the Plant Wansley permit on July 26, 2012, the Plant Kraft permit on September 24, 2012, and the Plant McIntosh permit on September 25, 2012.

[12] Plant Hammond Permit Condition 3.3.1, Plant Kraft Permit Condition 3.3.2, Plant McIntosh Permit at 3.3.9, Plant Wansley Permit Condition 3.3.6, Plant Scherer Permit Condition 3.3.8.

[13] *See* for example, 77 *Fed. Reg.* 9494-9498.

Enclosure B. Consistent with this approach, Georgia EPD explained in its response to comments on several of the draft permits that it "will add any necessary conditions for EGU MACT in a permit amendment in the future." Plant Kraft RTC at 2, Plant McIntosh RTC at 10, Plant Wansley RTC at 8. In light the above, the Petitioners have not demonstrated that it is necessary for the five permits addressed in their petitions to include additional detail regarding the specific EGU NESHAP requirements and associated monitoring prior to the MACT compliance date.

Claim 2: Petitioners' Claim that the Permits Should Clearly Require SO_2 CEMS Operation During All Periods of Operation Except CEMS Breakdown and Repair.

Petitioners' Claim.[14] In the Hammond, Scherer and Wansley petitions, the Petitioners contend that the monitoring included in the relevant permits is insufficient to assure compliance with the 95 percent SO_2 reduction requirement in Georgia Rule 391-3-1-.02(2)(uuu) ("Rule (uuu)").[15] The Petitioners assert that "it is unclear in the Permit[s] whether operation of SO_2 CEMS is required during startup, shutdown, and malfunction."[16] The Petitioners assert further that allowing the facilities to cease operation of the SO_2 CEMS during startup, shutdown and malfunction periods makes the CEMS insufficient to assure compliance with the SO_2 emission limitation set forth in permit conditions based on Rule (uuu). The Petitioners contend that Georgia EPD should revise the permit to clearly require CEMS operation at all times, including during startup, shutdown and malfunction.

EPA's response. For the reasons provided below, I am hereby notifying the state and the permittees of the EPA's determination that cause exists to reopen the Hammond, Scherer and Wansley permits. Pursuant to 42 U.S.C. § 7661d(e) and 40 C.F.R. §§ 70.7(f) and (g), the EPA has determined that the three permits identified in the Petitioners' claim contain material mistakes that require correction and are related to the Petitioners' claim. Specifically, the permits erroneously identify as federally enforceable permit conditions that cite to Georgia Rule 391-3-1-.02(2)(uuu) as their legal basis. Additionally, the EPA has determined that the permit for Scherer erroneously incorporates state-only exemptions from SO_2 CEMS operation contained in Georgia Rule 391-3-1-.02(2)(uuu)4 into federally enforceable conditions addressing monitoring for the SO_2 limit from the EPA's New Source Performance Standard (NSPS) at 40 C.F.R. part 60, Subpart D, 40 C.F.R. § 60.43(a)(2). *See* Scherer Permit Condition 5.2.21.[17]

Under 40 C.F.R. § 70.6(b)(2), "the permitting authority shall specifically designate as not being federally enforceable under the Act any terms and conditions included in the permit that are not required under the Act or under any of its applicable requirements." Several conditions in each of the three permits cite Georgia Rule 391-3-1-.02(2)(uuu) as their legal basis.[18] Georgia EPD submitted Georgia

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[14] Petitioners' claims regarding operation of the SO_2 CEMS appear in the Hammond Petition at 9-10, the Scherer Petition at 17-18, and the Wansley Petition at 9-11.

[15] The SO_2 emission limitations cited by Petitioner are: Hammond Permit at conditions 3.4.9; Scherer Permit at conditions 3.4.15-3.4.18; and Wansley Permit at conditions 3.4.13-3.4.14. These permit conditions cite Rule (uuu) as their legal basis.

[16] Hammond Petition at 9; Scherer Petition at 17; Wansley Petition at 9-10. The monitoring language that the Petitioner claims may exempt the source from the requirement to operate SO_2 CEMS during startup, shutdown, and malfunction periods also derives from Rule (uuu). Hammond Permit at conditions 5.2.11, 3.4.10; Scherer Permit at conditions 5.2.21, 3.4.19; Wansley Permit at conditions 5.2.14.

[17] The NSPS SO_2 limit is in Condition 3.3.4. Condition 5.2.4 specifies that the source must use SO_2 CEMS to assure compliance with the NSPS limit, and references the SO_2 CEMS requirement in Condition 5.2.1f. Condition 5.2.21 exempts the source from having to operate the SO_2 CEMS required by Condition 5.2.1f during any period allowed under Condition 3.4.19. Condition 3.4.19 contains the state-only CEMS exemptions provided in Georgia Rule 391-3-1-.02(d)(uuu)4.

[18] The Rule (uuu) SO_2 limit appears in the Hammond Permit at condition 3.4.9, in the Scherer Permit at conditions 3.4.15-3.4.18, and in the Wansley Permit at conditions 3.4.13-3.4.14. The associated CEMS requirements appear in the Hammond Permit at conditions 5.2.11, and 3.4.10, in the Scherer Permit at conditions 5.2.21 and 3.4.19, and in the Wansley Permit at

Rule 391-3-1-.02(2)(uuu) to the EPA for incorporation into the Georgia SIP, but the EPA has neither proposed approval nor taken final action on this submittal. Absent approval by the EPA, Georgia Rule 391-3-1-.02(2)(uuu) is not part of the Georgia SIP, and therefore is not a federally enforceable "applicable requirement," as defined by 40 C.F.R. § 70.2. The title V permits for Plants Hammond, Scherer and Wansley include numerous conditions labeled as "State Only Enforceable," but do not label the conditions related to Georgia Rule 391-3-1-.02(2)(uuu) as such, and Georgia EPD did not label these permit requirements based on Rule (uuu) as "not being federally enforceable" anywhere else. Also, the Scherer permit erroneously applies the state-only CEMS exemptions contained in Georgia Rule 391-3-1-.02(2)(uuu)4 to monitoring conditions for the federally enforceable SO_2 limit from 40 C.F.R. § 60.43(a)(2). Based on these findings, the EPA concludes that cause exists to reopen the three permits to correct these mistakes. In accordance with 42 U.S.C. § 7661d(e) and 40 CFR § 70.7(g), the EPA hereby notifies the Georgia EPD and the permittees of EPA's determination. In response to this notification, Georgia EPD must take action to: (1) ensure that any permit condition that cites to Georgia Rule 391-3-1-.02(2)(uuu) as its legal basis is designated as not being federally enforceable; (2) ensure that the CEMS exemptions from Georgia Rule 391-3-1-.02(2)(uuu)4 are not incorporated into permit conditions addressing monitoring for federal requirements; and (3) ensure and clarify that the federal portion of the permits contains the necessary monitoring requirements for the permits' federal SO_2 limits (e.g., Condition 5.2.4 from the Scherer Permit).

Accordingly, I am neither granting nor denying this claim. Clean Air Act section 505(b)(2) indicates the Administrator "shall grant or deny [a] petition within 60 days after the petition is filed." This provision does not direct how the Administrator must address the individual issues in each petition, thus providing the EPA with discretion in determining the best approach. The EPA may consider the complexity of the issues, the inter-relatedness of the issues, agency resources, public participation opportunities, source-specific considerations and other relevant factors in deciding the most appropriate approach for addressing the issues in each petition. *See also In the Consolidated Environmental Management, Inc. – Nucor Steel Louisiana*, Petition Nos. VI-201002 and VI-2011-03 at 11 (March 23, 2012) (*Nucor I Order*) ("Section 505(b)(2) does not specify whether the EPA must respond initially to all of the issues raised in a petition."). In this instance, the EPA has initiated a process to reopen the permits on which Petitioners' Claim 2 is based. Further, the questions underlying Petitioners' claims could be moot or could be substantively different depending on Georgia EPD's response to the EPA's determinations described above and the reopening for cause process.

Claim 3: Petitioners' Claim that the Permits' PM Monitoring Provisions Must be Strengthened.

Petitioners' Claim.[19] The Petitioners contend in their petitions on the Plant Hammond, McIntosh, Wansley and Scherer permits that the PM stack testing frequency required in the permits is insufficient to assure continuous compliance with the applicable hourly PM limitations.[20] Citing to *In re U.S. Steel*

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condition 5.2.14.

[19] Petitioners' claims regarding PM monitoring appear in the Plant Scherer Petition at 14-17, the Plant Hammond Petition at 6-9, the Plant McIntosh Petition at 3-8 and the Plant Wansley Petition at 6-9.

[20] Plant McIntosh's one steam generating unit is subject to a PM limit of 0.18 lb/MMBtu heat input under Georgia Rules 391-3-1-.02(2)(c) and .02(2)(d)1(ii). Plant McIntosh Permit Condition 3.4.1. Plant Scherer's four steam generating units are subject to a PM limit of 0.10 lb/MMBtu heat input under 40 C.F.R. § 60.42(a)(1) and Georgia Rule 391-3-1-.02(2)(d)2(iii). Plant Scherer Permit Condition 3.3.2. Plant Hammond's four steam generating units are subject to a PM limit of 0.24 lb/MMBtu heat input under Georgia Rule 391-3-1-.02(2)(d)1(iii). Hammond Permit Condition 3.4.1. Plant Wansley's two steam generating units are subject to a PM limit of 0.24 lb/MMBtu heat input under Georgia Rule 391-3-1-.02(2)(d)1(iii). Plant Wansley Permit Condition 3.4.1.

Corporation—Granite City Works, Order on Petition, Petition No. V-2009-03 (Jan. 31, 2011), the Petitioners contend that the EPA has already found "that PM compliance testing once every permit cycle (5 years) was facially insufficient to assure compliance with continuous limitations." The Petitioners acknowledge that the permits also require the facilities to monitor opacity using continuous opacity monitoring systems (COMS), but state that Georgia EPD does not discuss or try to establish a correlation between opacity limits and PM limits.[21] The Petitioners further contend that neither the permits nor Georgia EPD's responses to comments provide a detailed rationale as to why the chosen monitoring method is sufficient to assure compliance. The Petitioners claim that the permits should require a continuous emissions monitoring system (CEMS) for PM, or at a minimum, must include more frequent PM stack tests, e.g. quarterly, and the use of continuous parametric or surrogate monitoring with site specific correlations established during each stack test.[22] According to the Petitioners, "the variability of emissions, especially as they relate to the add-on controls," strongly indicates the necessity for continuous monitoring. The Petitioners contend that companies arrange diagnostic tests prior to official stack tests to ensure that their facility passes the stack tests, "even though particulate matter emissions may be much greater" during the rest of the five-to-ten-year period. The Petitioners note that PM CEMS "are increasingly employed at other coal-fired power plants," and that the EPA has "secured commitments from up to 30 existing coal-fired utility installations to install PM CEMS within the next few years." The Petitioners state that "[g]iven the use, reliability, and accuracy of monitoring requirements for similar emission units at other facilities, the EPA should object to the Permit and require the use of PM CEMS."

EPA's Response. For the reasons provided below, I deny the Petitioners' request for an objection to the permits on this claim. The Petitioners fail to demonstrate that the permits' monitoring requirements, viewed as a whole, are insufficient to assure compliance with the applicable PM limits. As discussed below, in addition to requiring stack testing, each permit includes parametric monitoring requirements designed to assure compliance with the applicable PM limits. Furthermore, contrary to Petitioners' assertion, the compliance assurance monitoring (CAM) plan attached to each of the facilities' permit applications, which is part of the title V permit record, shows a source-specific correlation between opacity levels and compliance with the applicable PM limits. Therefore, the Petitioners did not meet their burden of demonstrating that the permits are not in compliance with the requirements of the Act.

Further, although CEMS may be the preferred type of monitoring in some instances, CEMS are not always necessary to assure compliance with applicable requirements. Section 504(b) of the Act provides that "continuous emissions monitoring need not be required if alternative methods are available that provide sufficiently reliable and timely information for determining compliance." 42 U.S.C. § 7661c(b). *See also In re Alliant Energy WPL-Edgewater Generating Station,* Order on Petition, Petition Number V -2009-02 (August 17, 2010), at 11. The Petitioners neither identify an applicable requirement that compels the use of CEMS nor demonstrate that a CEM is the only monitoring method that can assure compliance with the applicable requirements.

As described in detail below, the Georgia Power permits at issue utilize a three-pronged approach for assuring compliance with the applicable PM limits: (1) performance testing to demonstrate that the

[21] Regarding Plant McIntosh, the petition notes that EPD "attempt[s] to correlate between opacity and PM," but contends that EPD's explanation was inadequate because the relationship between opacity and PM can differ based on load and EPD did not explain whether the stack tests were across a range of loads, and also because it is unclear whether EPD repeats the correlation analysis during every stack test.

[22] In the Plant Scherer petition, the Petitioner insisted that PM CEMS are necessary and did not suggest that parametric monitoring as a potentially acceptable substitute.

specified limit is being met; (2) continuous monitoring of the operation and maintenance of the applicable control devices to ensure continued proper operation (including monitoring operational parameters such as ESP indicator levels, opacity levels from COMs, number of recycling pumps in operation or sparger tube submergence levels for continuous monitoring of scrubbers/FGD); and (3) CAM plan requirements, including ranges of opacity along with additional secondary indicator monitoring in some cases.

The Petitioners have not demonstrated that Georgia EPD failed to provide a rationale for why the selected monitoring is sufficient to assure compliance with the applicable PM limits. To satisfy Part 70 requirements, "[t]he rationale for the selected monitoring requirements must be clear and documented in the permit record." *In re Public Service Company of Colorado, Pawnee Station*, Order on Petition, Petition No. VIII-2010-XX (June 30, 2011), at 12 (citing 40 C.F.R. 70.7(a)(5)). The permit record includes, among other things, the response to comments, the permit narrative, the permit application, and, for these permits, a CAM plan (or plans).[23] As discussed below, I find that, for each of the permits, the permit record sufficiently documents the rationale for the monitoring requirements selected to assure compliance with applicable PM emission limits.

Source-Specific PM Monitoring Requirements and Associated Rationale

Plant Hammond.

In response to comments, Georgia EPD explained that there is no requirement to install PM CEMS on Plant Hammond's four steam generating units (Units SG01-SG04), and that "PM testing requirements in Condition 4.2.1 and the operation of the Continuous Opacity Monitoring Systems (COMS) are sufficient monitoring requirements to ensure this facility will be able to comply with the PM and opacity emissions limits." Plant Hammond Permit RTC at 10. In addition, Georgia EPD's response points to Conditions 5.2.3 through 5.2.10 which explicitly list the CAM Plan requirements under 40 C.F.R. part 64 for SG01-SG04. *Id.* at 11. Georgia's EPD's response guides the commenter to the State's website where the CAM Plan electronic documents can be found (Application No. 19763). *Id.* Plant Hammond Permit Condition 4.2.1.b requires PM testing of SG01-SG04 stack (ST03) annually, unless previous test results were less than 50 percent of the limit of 0.24 lb/MMBtu, in which case the testing can be delayed no more than 12 months. Hammond Permit Condition 4.2.1a also requires PM testing of SG01, SG02 & SG03 scrubber bypass stack (ST01) and SG04 (ST02) after 8760 hrs of bypass operation or five years to show compliance with the limit of 0.24 lb/MMBtu. Consistent with the CAM plan, between stack tests compliance is assured through the use of parametric monitoring. Specifically, the permit requires continuous opacity monitoring upstream of the FGD scrubbers with dedicated COMS. Permit Condition 5.2.1a. The permit identifies as an exceedance "[a]ny six-minute period during which the average opacity, as measured by the COMS…exceeds 40 percent." Permit Condition 6.1.7.b.i. The permit identifies as an excursion requiring corrective action for Source 1 (comprised of steam generating units 1, 2 and 3) as "any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 40 percent." Permit Condition 6.1.7.c.i. For Source 2 (comprised of steam generating unit 4), an excursion occurs whenever the three-hour block average opacity exceeds 37 percent. Permit Condition 6.1.7.c.ii. The permit also requires continuous monitoring of ESP power and continuous monitoring of the number of recycle pumps to maintain performance of the Flue Gas Desulfurization ("FGD") unit. Permit Condition 5.2.10.

[23] CAM plans for these facilities are available on Georgia EPD's website at *http://airpermit.dnr.state.ga.us/GATV/GATV/TitleV.asp*.

The rationale for the selected opacity level, ESP power level, and FGD number of recycle pumps running is provided in the permit narrative and in the CAM plans attached to Georgia Power's permit applications and included in the permit record. Specifically, Plant Hammond's CAM plan dated 4/27/04 explains that when opacity is below 40 percent for Source 1, or below 37 percent for Source 2, "test data indicates a reasonable assurance that the PM emissions will be significantly less than the permit limit." Hammond CAM Plan at 4, 8. The plan confirms that if the three-hour opacity average for either source approaches the specified level, "action will be taken to reduce the average as soon as possible." *Id.* The CAM plan further states: "The CAM opacity cap was established by measuring the particulate emissions at different opacity levels in the combined ESP exhausts ... no changes have taken place that could result in a significant change in the precipitator performance or the selected indicator ranges since the compliance or performance test was conducted." *Id.* Regarding monitoring of the ESP power level and the FGD number of recycle pumps running, the permit itself explains that the ESP power and the number of FGD1 recycle pumps running and minimum rotations per minute (RPM) detected are indicators of particulate matter collection and equipment performance. Hammond Permit Condition 5.2.10. The permit narrative explains: "If the ESP power falls below the established threshold, then the number of pumps operating and the RPM for each of the pumps at the time will be verified. An excursion will be reported if the ESP power falls and the number of pumps is less than the minimum and the RPMs are below the threshold." Permit narrative at 15. The narrative further explains: "The scrubber is a secondary control device and compliance has been routinely demonstrated during the annual performance testing prior to installation of the scrubber." *Id.*

Plant Scherer.

In response to comments, Georgia EPD explained that there is no requirement to install PM CEMS on these units, and that "PM testing requirements in Condition 4.2.1 and the operation of the Continuous Opacity Monitoring Systems (COMS) are sufficient monitoring requirements to ensure this facility will be able to comply with the PM and opacity emissions limits." Plant Scherer Permit RTC at 7. The Plant Scherer permit requires PM testing of SG01, SG02, SG03 and SG04 scrubber stacks (ST05, ST06, ST07 & ST08) once every 5 years (Permit Condition 4.2.1b) for a limit of 0.10 lb/MMBtu (Permit Condition 3.3.3). The permit also requires PM testing of SG01, SG02, SG03 and SG04 scrubber bypass stacks (ST01, ST02, ST03 & ST04) after 8760 hours of bypass operation or 5 years unless previous results were 50 percent or less of limit of 0.10 lb/MMBtu. Permit Condition 4.2.1a. Between PM stack tests, the permit assures compliance with PM limits using parametric monitoring. Specifically, the permit requires continuous opacity monitoring upstream of the FGD scrubbers with dedicated COMS. Permit Condition 5.2.1b. For each of the steam generator units, Permit Condition 6.1.7 defines as an excursion (i.e., a departure from an indicator range) "any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 20 percent." For SG03 and SG04, the permit supplements opacity monitoring with a second compliance indicator: the number of FGD recycle pumps running. Conditions 5.2.8 and 5.2.9.

The rationale for the monitoring selected to assure compliance with applicable PM limits is provided in the permit, the permit narrative, and in Plant Scherer's CAM plan (attached to the permit application and included in the permit record). As the permit narrative explains, SG01, SG02, SG03 and SG04 and the associated FGD Scrubber and ESP are subject to the CAM plan requirements of 40 CFR part 64 for control of PM. Plant Scherer Permit Narrative at 14. The parametric monitoring requirements included in the permit to assure compliance with the PM limit are taken from the plant's CAM plan dated 4/27/04. Regarding the required opacity monitoring, the CAM plan explains that for each of the units, when opacity is below 20 percent, "test data indicates a reasonable assurance that the PM emissions will be less than the permit limit." CAM plan at 4 (SG01), at 8 (SG02), at 12 (SG03), at 16 (SG04). The plan

further states: "If the three-hour opacity average approaches 20%, action will be taken to reduce the average as soon as possible." *Id.* According to the plan, the opacity cap "was established by measuring the particulate emissions at different opacity levels in the ESP exhaust." *Id.* The plan explains: "No changes have taken place that could result in a significant change in the precipitator performance or the selected indicator since the compliance or performance test was conducted." *Id.* The requirement to monitor the number of FGD recycle pumps running at Units SG03 and SG04 is based on a CAM plan modification submitted on June 22, 2011. As the permit explains: "The number of FGD pumps running is an indicator of particulate matter collection and equipment performance of the FGD." Plant Scherer Permit Conditions 5.2.8 and 5.2.9. The 2011 CAM plan modification summarizes test data indicating the correlation between the number of FGD recycle pumps running and particulate matter emissions. 2011 CAM Plan at 3.

Plant Wansley.

In response to comments, Georgia EPD explained that there is no requirement to install PM CEMS on these units and that "PM testing requirements in Condition 4.2.1 and the operation of the Continuous Opacity Monitoring Systems (COMS) are sufficient monitoring requirements to ensure this facility will be able to comply with the PM and opacity emissions limits." Plant Wansley Permit RTC at 6. The Plant Wansley permit requires PM testing of SG01 & SG02 scrubber stacks (ST03 & ST04) every 5 years (Permit Condition 4.2.1b) to show compliance with a limit of 0.24 lb/MMBtu (Permit Condition 3.4.1). The permit also requires PM testing of SG01 & SG02 scrubber bypass stacks (ST01 & ST02) after 8760 hours of bypass operation or 5 years (Permit Condition 4.2.1a) to show compliance with the PM limit of 0.24 lb/MMBtu (Permit Condition 3.4.1). Between PM stack tests, the permit assures compliance with PM limits using parametric monitoring. The permit narrative explains that PM emissions from Steam Generating Units 1 and 2 are each controlled by an ESP (Source Codes EP01 and EP02) on the bypass stack liner and controlled by a FGD system (Source Codes FGD1 and FGD2) on the main stack liners. Plant Wansley Permit Narrative at 26. Permit Condition 5.2.1 requires the Permittee to install and operate a COMS on SG01 and SG02 located in each liner of the scrubber bypass stacks. Performance criteria for the COMS are established in Permit Conditions 5.2.6 and 5.2.7. Under Permit Condition 6.1.7.b, any six-minute period during which the average opacity, as measured by the COMs for Units SG01 and SG02, exceeds 40 percent shall be reported as an exceedance. In addition, for Units SG01 and SG02, the permit defines as an excursion requiring corrective action any 3-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 40 percent. Permit Condition 6.1.7.c. For parametric monitoring of the main stacks, the permit requires the Permittee to install and operate a continuous monitoring system (CMS) for the measurement of the sparger tube liquid submergence level in the scrubber vessels for Units SG01 and SG02. Permit Condition 5.2.2. Performance criteria pertaining to the sparger tube liquid submergence level are provided in Permit Conditions 5.2.6 and 5.2.7. The permit defines an excursion requiring corrective action for the FGDs as a 3-hour-average scrubber vessel sparger tube liquid submergence level less than 5.0. Permit Condition 6.1.7.c.iv).

The rationale for the monitoring selected to assure compliance with applicable PM limits is provided in the permit, the permit narrative, and in Plant Wansley's CAM plan (attached to the permit application and included in the permit record). For the bypass stacks, the permit narrative explains that COMS are the primary indicator that the ESP is operating properly. Plant Wansley Permit Narrative at 26. The narrative reports: "It has been determined that the opacity cap levels indicating unacceptable performance are: for Unit 1, a three-hour average of 40% opacity and for Unit 2, a three-hour average of 40% opacity." *Id.* For the main stacks, the permit narrative explains that the FGD scrubber is designated as the primary control device to achieve compliance with the PM standard. The narrative further

explains that the primary indicator that the FGD scrubber is working properly is the sparger tube liquid submergence level in the FGD vessel for each unit. *Id.* According to Plant Wansley's CAM plan dated 1/26/2009: "Test data indicates particulate matter emissions will be well below the permit limit even with the ESP out of service if the JBR sparger tubes submergence level is maintained at or above 5.0 inches of liquid." Wansley CAM Plan at 4. The CAM plan includes a table summarizing test data showing the relationship between particulate matter emissions and the JBR sparger tube submergence level. *Id.* at 7.

Plant McIntosh.

In response to comments, Georgia EPD explained that there is no requirement to install PM CEMS on Plant McIntosh's steam generating unit (unit SG01), and that "PM testing requirements in Condition 4.2.1 and the operation of the Continuous Opacity Monitoring Systems (COMS) are sufficient monitoring requirements to ensure this facility will be able to comply with the PM and opacity emissions limits." Plant McIntosh RTC at 9. The Plant McIntosh permit requires PM testing of SG01 annually unless previous test results were less than 50 percent of the limit of 0.18 lb/MMBtu, in which case the testing can be delayed no more than 12 months. Permit Condition 4.2.1a. The Permittee must monitor opacity continuously with a dedicated COMS. Permit Condition 5.2.1.a. Performance criteria for the COMS are identified in Permit Condition 5.2.12. The permit identifies as an exceedance "[a]ny six-minute period during which the average opacity, as measured by the COMS for the steam generating unit (Emission Unit ID SG01) exceeds 40 percent." Permit Condition 6.1.7.b.iv. The permit explains that an excursion requiring corrective action occurs when "any three-hour block average during which the arithmetic average opacity, as measured by the COMS, exceeds 28 percent (for combustion of fuel which does not include Pine Branch coal) or 22.5 percent (for combustion of fuel which includes Pine Branch coal)." Permit Condition 6.1.7.c.i.

The rationale for COMS as a PM monitoring approach is provided in the permit, the permit narrative, and in Plant McIntosh's CAM plan (attached to the permit application and included in the permit record). The permit narrative explains that the steam generating unit is controlled by an ESP, and the primary indicator of proper control device operation for particulate matter is a COMS. Permit Narrative at 25. Thus, the narrative explains that a COMS will be used to assure compliance with the opacity standard as well as the PM standard. McIntosh Permit Narrative at 22. More specifically, the permit narrative explains: "To assure compliance with the particulate standard, an Opacity Index Value was established for SG01. The Opacity Index Value is the opacity level at which particulate matter emissions would be expected to be at or near the allowable limit (0.18 pounds per million Btu) and was established by correlating test data from previous PM emissions tests with the corresponding opacity levels during the testing." *Id.* at 22. The narrative further explains: "It has been determined that the opacity cap level indicating unacceptable performance is a three-hour average of 28% opacity." Narrative at 25. The Plant McIntosh CAM plan dated 7/30/2004 explains that when opacity is below 28%, "test data indicates a reasonable assurance that the PM emissions will be less than the permit limit." CAM Plan at 4. The plan further explains: "If the three-hour opacity average approaches 28%, action will be taken to reduce the average as soon as possible. If the 3-hour opacity average exceeds 28%, a CAM excursion has occurred."[24] *Id.* According to the plan: "The CAM opacity cap was established by measuring the particulate emissions at different opacity levels in the ESP exhaust ... No changes have taken place that

[24] The permit narrative for the 2007 Plant McIntosh title V permit renewal (Permit No. 4911-103-0003-V-02-0) explains that the more stringent CAM excursion opacity level applicable when the plant is using Pine Branch coal is in accordance with Consent Order No. EPD-AQC-1596 executed on April 28, 2000. 2007 Renewal Permit Narrative at 16. The narrative for the 2012 Plant McIntosh renewal permit at issue in this order includes a table referencing the 2007 title V permit renewal action. Plant McIntosh Narrative at 3.

could result in a significant change in the precipitator performance or the selected indicator since the compliance or performance test was conducted." *Id.*

Correlation Between PM and Opacity

Regarding the Petitioners' claim that the permit records lacked a source-specific correlation between opacity and PM emissions—or, in the case of Plant McIntosh, that the record lacked an adequate correlation that would be reconfirmed in future stack tests—this claim was not raised with reasonable specificity in comments to Georgia EPD on the draft permits. Nor is there any demonstration in the petitions that it was impracticable to do so or evidence that the grounds arose after the comment period. As discussed above, under CAA § 505(b)(2): "The petition shall be based only on objections to the permit that were raised with reasonable specificity during the public comment period provided by the permitting agency (unless the petitioner demonstrates in the petition to the Administrator that it was impracticable to raise such objections within such period or unless the grounds for such objection arose after such period)." Accordingly, I deny the Petitioners' correlation claim on procedural grounds. However, as noted above, Georgia Power's CAM plan for each plant does show the correlation between opacity and PM emissions.

PM Monitoring Adequacy

Regarding the Petitioners' claim that the overall approach to PM monitoring set forth in the permits is insufficient to assure compliance with applicable PM limitations, the Petitioners have not met their burden of demonstrating that the PM monitoring is insufficient. The suite of monitoring requirements included in each permit as described above, including PM stack testing and parametric monitoring (continuous opacity monitoring, and where appropriate and necessary, other parametric monitoring of control equipment) is consistent with the monitoring approach we reviewed in a number of orders. *See In re Wisconsin Public Service Corporation's JP Pulliam Power Plant*, Petition V-2012-01 (Jan. 7, 2013); *In re Public Service Company of Colorado, dba Xcel Energy, Hayden Station*, Petition VIII-2009-01 (March 24, 2010), at 5. *In re Public Service Company of Colorado, dba Xcel Energy,Pawnee Station*, Petition VIII-2010-XX (June 30, 2011), at 12; *In re Public Service Company of Colorado, dba Xcel Energy, Cherokee* Station, Petition VIII-2010-XX (September 29, 2011), at 11; *In re Public Service Company of Colorado, dba Xcel Energy, Valmont Station*, Petition VIII-2010-XX (September 29, 2011), at 10. While the Petitioners insist that the permits' stack testing requirements are insufficient to assure compliance with short-term PM limits, the Petitioners fail to demonstrate the inadequacy of the associated parametric monitoring described in the CAM plans and included in the permits as part of the broader suite of PM monitoring. Likewise, the Petitioners' contention that the COMS monitoring is ineffective due to the lack of a source-specific correlation between opacity and PM emissions is not supported by the record; as discussed above, the CAM plan for each facility provides this source-specific correlation. These plans were included in the permit records and were available for public review during the public comment period.[25]

As mentioned above, under title V a petitioner has the burden to demonstrate to the EPA that a permit is not in compliance with the requirements of the Act. *Sierra Club v. Johnson, 541 F.3d 1257, 1266-1267*

[25] As explained above, the correlation issue was not raised with reasonable specificity in comments to the Georgia EPD on the draft permits, and therefore, the EPA is denying the correlation claims on procedural grounds. Alternatively, even if the correlation claims had been raised with reasonable specificity in comments on the draft permits, the EPA denies the correlation claims on the basis that the Petitioners did not demonstrate the inadequacy of the correlations provided in the CAM plans, which were available in the permit records.

(11th Cir. 2008); Citizens Against Ruining the Environment v. EPA, 535 F.3d 670, 677-678 (7th Cir. 2008); Sierra Club v. EPA, 557 F.3d 401, 406 (6th Cir. 2009); McClarence v. EPA, 596 F.3d 1123, 130-31 (9th Cir. 2010) (discussing the burden of proof in title V petitions). Because the Petitioners simply challenge the lack of CEMS and the frequency of stack testing without addressing the overall monitoring scheme for the PM limits in the permits, the Petitioner failed to demonstrate that the monitoring requirements in the permit are insufficient to assure compliance with the PM limits. Furthermore, contrary to the Petitioners' contention, the permit record for each of the permits provides the rationale for the selected monitoring regime. Therefore, I deny the Petitioners' request for an objection to the permits based on alleged deficiencies in the permits' PM monitoring requirements and the purported lack of an explanation in the permit record for the selected PM monitoring approach.

Claim 4: Petitioners' Claim that Permits Must Include Provisions to Control Fugitive Dust from the Coal, Ash and Material Handling Systems.

Petitioners' Claims. In their petitions on the Plants Hammond, Kraft, McIntosh, Wansley and Scherer permits, the Petitioners claim that the permits lack "the specific, enforceable best management practices necessary to eliminate or minimize fugitive dust" generated from the facilities' various coal, ash and material handling operations (the specific operations vary depending upon the facility). The Petitioners allege three deficiencies related to this issue. The Petitioners allege that this lack of specificity contravenes Georgia SIP Rule 391-3-1-.02(2)(n)1, which "includes a non-exhaustive list of specific control devices and practices that should be applied to the facility and detailed in its Title V permit as enforceable conditions." The Petitioners also state that the condition in each permit requiring the facilities to take "reasonable precautions" is vague and unenforceable. According to the Petitioners, the permits should specify "[t]he required frequency, quantity and duration of dust suppression techniques." Finally, the Petitioners contend that the permits do not include monitoring and reporting of control devices and practices to demonstrate compliance with the twenty percent opacity limit in Georgia SIP Rule 391-3-1-.02(2)(n)2. *See* Plant Scherer Petition at 20-21, Plant Hammond Petition at 11-12, Plant Kraft Petition at 4-5, Plant McIntosh Petition at 9-10, Plant Wansley Petition at 12-13.

EPA's Response. For the reasons provided below, I grant the Petitioners' request for an objection to the permits based on deficiencies in the permit conditions implementing the fugitive dust control requirements of Georgia SIP Rule 391-3-1-.02(2)(n).

The permits' fugitive dust control requirements are taken directly from Georgia SIP Rule 391-3-1-.02(2)(n). This SIP provision requires source operations which may generate fugitive dust to "take all reasonable precautions to prevent such dust from becoming airborne." This provision identifies "[s]ome reasonable precautions which <u>could be taken</u> to prevent dust from becoming airborne," (Georgia SIP Rule 391-3-1-.02(2)(n)1 (emphasis added)), but the SIP does not specifically require that a source take a specific action. Thus, the lack of a condition in the permits requiring that the sources take the precautions identified in the rule does not contravene the SIP. However, the EPA determines that the Petitioners met their burden of demonstrating that without details regarding what type of actions qualify as "reasonable precautions" to control fugitive dust at these facilities, the permits do not assure compliance with Georgia SIP Rule 391-3-1-.02(2)(n)1.

Under CAA § 504(a), "[e]ach permit issued under this subchapter shall include enforceable emission limitations and standards...and such other conditions as are necessary to assure compliance with the applicable requirements of this chapter, including the requirements of the applicable implementation plan." Likewise, the EPA's regulations specify that each Title V permit must include <u>"[e]missions</u>

limitations and standards, including those operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance." 40 C.F.R. § 70.6(a)(1) (emphasis added). *See also* 40 C.F.R. § 70.6(c)(1).

The "reasonable precautions" requirement at Georgia SIP Rule 391-3-1-.02(2)(n)1 is an "applicable requirement" for title V purposes. While the SIP regulation identifies various fugitive dust control methods that may constitute "reasonable precautions," it does not mandate the use of any of these methods. For a title V permit to assure a particular source's compliance with this requirement, consistent with 40 C.F.R. § 70.6(a)(1) and the approved Georgia title V program at Georgia Air Quality Rule 391-3-1-.03(10), the permit terms must specify the emissions limitations and standards, including those operational requirements and limitations that assure compliance with the applicable requirement in Georgia SIP Rule 391-3-1-.02(2)(n)1. I find that the Petitioners demonstrated a flaw in the permit.

Because there can be many different interpretations of what constitutes "reasonable precautions" to control fugitive dust, the State's contention that the Petitioners' concerns are addressed by a permit condition requiring that the facility record steps taken to control fugitive emissions is inapposite in light of the permit's lack of specificity.[26] Likewise, while the State points out that the permits also require compliance with the SIP's 20 percent opacity limit, the State fails to explain how the existence of the opacity limit assures compliance with the "reasonable precautions" standard and there is no such explanation in the permit records.

In response to this Order, the EPA directs Georgia EPD to take action to include in the title V permits for Plants Hammond, Kraft, McIntosh, Wansley and Scherer emissions limitations and standards, including those operational requirements and limitations that assure compliance with Georgia SIP Rule 391-3-1-.02(2)(n)1.[27] In addition, Georgia EPD must provide a rationale in the permit record explaining why the permit conditions are sufficient to assure compliance with Georgia SIP Rule 391-3-1-.02(2)(n)1,including necessary monitoring, recordkeeping and reporting. The EPA notes that the Plant Scherer permit includes a wet suppression requirement under the applicable NSPS (Scherer Permit Condition 6.2.5) that potentially could be construed as sufficient to assure compliance with the reasonable precautions standard at Plant Scherer's railcar unloading area. If Georgia EPD concludes that this requirement is sufficient to assure compliance with Georgia SIP Rule 391-3-1-.02(2)(n)1 at Plant Scherer's railcar unloading area, Georgia EPD must provide the basis for such determination in a rationale included in the permit record.

Finally, regarding whether the permit conditions are sufficient to assure compliance with the 20% opacity limit in Georgia SIP Rule 391-3-1-.02(2)(n)2, I find that the Petitioners have demonstrated that neither the permits nor the permit records indicate how the permits assure compliance with the limit, as required by 40 CFR §§ 70.6(a)(3)(i)(B) and 70.6(c)(1). Though the Petitioners commented to the Georgia EPD that the draft permits "should be subject to monitoring and reporting to demonstrate compliance with a 20 percent opacity limit,"[28] Georgia EPD's response lacks any explanation as to how

[26] Plant Scherer Permit RTC at 9; Plant Wansley Permit RTC at 7; Plant Kraft Permit RTC at 3; Plant Hammond Permit RTC at 12; Plant McIntosh RTC at 10.

[27] For Plants Hammond, Wansley and Scherer, the affected units are the Coal Handling System (CHS), the Ash Handling System (AHS) and the Materials Handling System (MHS). For Plant Kraft, the affected units are the Coal Handling System (CHS), the Transfer and Loading Equipment, Including the Transloader System (TLS) and the Ash Handling System (AHS). For Plant McIntosh, the affected units are the Coal Handling System (CHS) and the Ash Handling System (AHS).

[28] GreenLaw Comments on draft Wansley Permit dated May 18, 2012, at 21-22; GreenLaw Comments on draft Hammond Permit dated November 14, 2011, at 24; GreenLaw Comments on draft McIntosh Permit dated July 5, 2012, at 15; GreenLaw Comments on draft Scherer Permit dated October 21, 2011, at 21. *See also* Comments by Kurt Ebersbach, et al. on draft Kraft

the permit assures compliance with the opacity limit. While Georgia EPD's response refers to the condition in each of the facilities' permits "to maintain a record of all actions taken … to suppress fugitive dust," Georgia EPD does not explain how that permit condition might relate to assuring compliance with the 20 percent opacity limit. Furthermore, nothing in the permit record indicates that the permit contains monitoring, recordkeeping and reporting obligations sufficient to assure compliance with the 20 percent opacity limit. Therefore, I also grant the petitions on this aspect of the Petitioners' claim. In response to this Order, the EPA directs the Georgia EPD to identify the specific methods and the monitoring to be used by Georgia Power to assure compliance with the 20 percent opacity limit for the fugitive dust sources at Plants Hammond, Kraft, McIntosh, Wansley and Scherer consistent with 40 CFR §§ 70.6(a)(3)(i)(B) and 70.6(c)(1), and provide an adequate rationale for the chosen methods in the permit record.

Claim 5: Petitioners' Claim that the Plant Scherer Permit Must Include Limitations to Comply with both PSD and NNSR.

The Petitioners claim that recent and planned upgrades to Plant Scherer's four steam turbines constitute a "modification" that should have triggered applicability of PSD and NNSR requirements; therefore, the Petitioners claim the Plant Scherer permit is deficient because it omits PSD and NNSR limitations. Scherer Petition at 3-11. The Petitioners further claim that Georgia EPD failed to provide a reasoned analysis of why PSD and NNSR are not applicable to this project. *Id.* According to the Petitioners, Georgia EPD's responses to Sierra Club's comments on the draft permit did not address Sierra Club's concerns, "but rather improperly required additional reporting on the emissions once the project is complete, which is irrelevant to the preconstruction analysis." Scherer Petition at 8. The Petitioners claim that the PSD/NNSR applicability analysis performed by Georgia Power and relied upon by Georgia EPD was flawed because it improperly accounted for emission reductions resulting from installation of pollution controls required by Georgia Rules 391-3-1-.02(2)(sss) and the accompanying SO_2 emission reductions required under Georgia Rule 391-3-1-.02(2)(uuu). Scherer Petition at 3-11. The Petitioners also state that "the required applicability review for PM and SO_2, which contribute to PM2.5 emissions, is properly termed 'new source nonattainment review'" and that the analysis for nonattainment NSR is the same as PSD. Petition at 11. The Petitioners' specific allegations regarding deficiencies in the PSD/NNSR applicability analysis are described in detail below.

1. **Georgia Power Incorrectly Considered Emission Reductions Anticipated from the Facility's Installation of SO_2 Controls Required by Georgia Rules in Determining that the Turbine Project Will Not Cause a Significant Emissions Increase Under Step One of the PSD/NNSR Applicability Analysis.**

Petitioners' Claim: The Petitioners contend that under Step One of the PSD/NNSR applicability analysis,[29] Georgia Power's calculation of whether the turbine upgrade project would result in a "significant emissions increase" improperly considered emission reductions anticipated from Georgia Power's installation of SO_2 controls (simultaneous with the Turbine Upgrade Project) required by Georgia Rule 391-3-1-.02(2)(sss) and accompanying reductions in SO_2 required under Georgia Rule 391-3-1-.02(2)(uuu). Scherer Petition at 7-9. In particular, the Petitioners argue that in applying the

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Permit dated June 6, 2012, at 8-10 (noting that the permit applies the 20 percent opacity standard to the facility's coal handling operations "but does not include the specific, enforceable best management practices necessary to eliminate or minimize fugitive dust from this component of the plant.").

[29] *See* page 23, *infra*, for an explanation of the two-step analysis for determining PSD and NNSR applicability.

"actual-to-projected-actual" methodology for determining whether the Turbine Upgrade Project would result in a "significant emissions increase," Georgia Power incorrectly subtracted the emission reductions anticipated to be achieved by the installation of emission controls from the Turbine Upgrade Project's "projected actual emissions."[30] Scherer Petition at 9.

According to the Petitioners, Georgia Power should not have considered the emission reductions obtained from anticipated compliance with Georgia Rules 391-3-1-.02(2)(uuu) and (sss) in calculating the project's "projected actual emissions" because these emission reductions are "unenforceable." Scherer Petition at 9. Specifically, the Petitioners contend that "the reductions are not enforceable as a practical matter, because neither rule is enforceable during periods of allowable excess emissions (broadly defined periods of startup, shutdown and malfunction), and there is no requirement for continuous monitoring during such episodes." Scherer Petition at 10.

The Petitioners also contend that if the emission reductions resulting from Georgia Power's installation of SO_2 controls to comply with state regulatory requirements are in fact enforceable, Georgia Power should have adjusted the "baseline actual emissions"[31] used in the "actual-to-projected actual" calculation downward to reflect the required emission reductions. Scherer Petition at 9. Citing to 40 C.F.R. § 52.21(b)(48)(ii)(c)[32] and Georgia's PSD Guidance, the Petitioners contend that "baseline actual emissions" must be adjusted downward to account for any "new emissions limitations with which the source must currently comply."[33] *Id.* The Petitioners state that if Georgia Rules (uuu) and (sss) are enforceable, then they constitute "emission limitations with which the source must currently comply" and therefore must be accounted for in the facility's "baseline actual emissions." *Id.*

In sum, regarding consideration of the emission reductions anticipated from compliance with Georgia Rules (uuu) and (sss), the Petitioners contend that "either the limits were enforceable and should have been subtracted from the baseline emissions rate; or the emissions [reductions] were not enforceable and should not have been subtracted from the final actual annual emissions post-project." Scherer Petition at 9. According to the Petitioners, "either result would have made the baseline actual emissions and the

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[30] Under Georgia's SIP-approved PSD rules at Georgia Rule 391-3-1.02(7)(a)2.(ii)(I), the term "Projected actual emissions" is defined as "the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the five years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source." This definition also is incorporated into Georgia's SIP-approved NNSR rules at Georgia Rule 391-3-1-.03(8)(g)1.

[31] Georgia's SIP-approved PSD rules (at Georgia Rule 391-3-1.02(7)(a)2.(i)(I)) define "Baseline actual emissions" for an existing electric utility steam generating unit as "the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project." This definition also is incorporated into Georgia's SIP-approved NNSR rules at Georgia Rule 391-3-1-.03(8)(g)1.

[32] 40 C.F.R. § 52.21(b)(48)(ii)(c) applies to "existing emissions units (other than an electric utility steam generating unit)" and requires that in calculating "baseline actual emissions," the "average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply."

[33] It should be noted that 40 C.F.R. § 52.21(b)(48)(i), which applies to existing electric utility steam generating units, does not require that "baseline actual emissions" be adjusted downward to account for new emission limitations with which the source must "currently comply;" but Georgia's PSD and NNSR regulations for existing electric utility steam generating units do require this adjustment. *See* Georgia Rule 391-3-1.02(7)(a)2.(i)(I).VI. ("The average rate shall be adjusted downward to exclude any emissions that would have exceeded an emission limitation with which the major stationary source must currently comply, had such major source been required to comply with such limitations during the consecutive 24-month period."); *see also* Georgia Rule 391-3-1-.03(8)(g)1 (incorporating this language in Georgia's NNSR regulations).

projected annual emissions or potential to emit much closer, and would likely have resulted in a finding of significant emissions increase." *Id.*

Finally, the Petitioners contend that by counting the emission reductions obtained from anticipated compliance with Georgia Rules 391-3-1-.02(2)(uuu) and (sss) in Step One of the PSD/NNSR applicability analysis, "Georgia Power incorrectly collapsed both the significant emissions increase and significant net emissions increase steps into one step." Scherer Petition at 8. The Petitioners state that "because it appears that Georgia Power incorporated incorrect emissions reductions into its collapsed version, it is likely that a more-detailed analysis would uncover that Georgia Power's changes have resulted in triggering PSD and limitations related to that program must be incorporated into the Permit." *Id.*

EPA's Response. For the reasons provided below, I deny the Petitioners' request for an objection to the permit on this claim. The Petitioners failed to demonstrate that in determining that Plant Scherer's Turbine Upgrade Project did not trigger PSD/NNSR requirements, Georgia EPD did not comply with its SIP-approved regulations governing PSD/NNSR permitting or that Georgia EPD's exercise of discretion under such regulations was unreasonable or arbitrary.

First, regarding the Petitioners' claim that the emission reductions associated with compliance with Georgia Rules (uuu) and (sss) cannot be considered in the "projected actual emissions" determination because these reductions are (allegedly) unenforceable, neither the Petitioners nor any other commenter raised this issue with reasonable specificity in their comments to Georgia EPD on the draft permit. Nor do the Petitioners demonstrate that it was impracticable to raise this argument, and there is no basis for finding that grounds for such argument arose after the comment period. Thus, I deny this aspect of the Petitioners' claim on procedural grounds. CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2). However, the issue of whether controls or their effect on emissions must be "enforceable" to be considered in determining a unit's "projected actual emissions" is relevant to the EPA's response to the Petitioners' claim that Georgia Power's consideration of emission reductions resulting from the installation of controls improperly collapsed Steps One and Two of the PSD/NNSR applicability analysis. Therefore, the EPA addresses this issue below.

Second, neither the Petitioners nor any other commenter raised with reasonable specificity in their comments to Georgia EPD on the draft permit the argument that the project's "baseline emissions" should have been lowered to account for emission reductions attributable to compliance with Georgia Rules (uuu) and (sss). While comments to Georgia EPD on the draft Plant Scherer permit generally alleged that Georgia Power "took into account the effect of such other projects as the installation and operation of the SCR and scrubber systems required to be installed under Rule (sss), and the accompanying reductions in SO_2 emissions required under rule (uuu)," (GreenLaw comments at 10), the Petitioners did not specifically allege that the baseline should have been lowered. Rather, the Petitioners' comments focused on the argument that in Step One of the applicability analysis, emission decreases associated with pollution control projects and accompanying limits cannot be considered. *See* GreenLaw Comments at 12. The Petitioners did not demonstrate that it was impracticable to raise its concern regarding the "baseline emissions" calculation in its comments on the draft permit, and there is no basis for finding that grounds for this argument arose after the comment period. Accordingly, I also deny this aspect of the Petitioners' claim on procedural grounds. CAA § 505(b)(2), 42 U.S.C. § 7661d(b)(2).

The EPA has noted the importance of the requirement that petitioners raise issues with reasonable specificity to the state permitting authority:

As the EPA stated in the proposal to the original title V regulations:

> The EPA believes that Congress did not intend for Petitioners to be allowed to create an entirely new record before the Administrator that the State has had no opportunity to address. Accordingly, the Agency believes that the requirement to raise issues 'with reasonable specificity' places a burden on the Petitioner, absent unusual circumstances, to adduce before the State the evidence that would support a finding of noncompliance with the Act.

56 Fed. Reg. 21712, 21750 (1991). Thus, a title V petition should not be used to raise issues to the EPA that the State has had no opportunity to address, and the requirement to raise issues 'with reasonable specificity' places a burden on the petitioner, absent unusual circumstances, to adduce before the State the evidence that would support a finding of noncompliance with the Act. *Id.*

In the Matter of Luminant Generating Station, Petition No. VI-2011-05, Order on Petition, August 28, 2011 at 5.

Finally, regarding the Petitioners' more general claim that Georgia Power's consideration of the emission reductions expected from the installation of controls pursuant to Georgia Rules (uuu) and (sss) incorrectly collapsed Step One (the significant emissions increase) and Step Two (significant net emissions increase) steps into one step, I find that the Petitioners did not make the demonstration necessary to support that claim. As explained below, based on the EPA's review of the permit record and the applicable legal requirements, I find that the Petitioners have not demonstrated that it was inappropriate for Georgia Power to consider the effect of the pollution controls installed pursuant to Georgia Rules (uuu) and (sss) in Step One of the PSD/NNSR applicability analysis for Plant Scherer's Turbine Upgrade Project.[34]

When determining if a project at an existing major source is a "major modification"[35] that triggers PSD or NNSR requirements, it is necessary to first evaluate whether the project will result in a "significant emissions increase" (Step One). One option for making this determination is to apply the "actual-to-projected-actual" test.[36] This is the option used by Georgia Power to determining whether PSD and

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[34] The basis for Georgia Power's determination that the Turbine Upgrade Project did not trigger PSD or NNSR appears in the narratives accompanying the two permit revisions that address the project. *See* Narrative for Permit Revision #4911-207-0008-V-02-A (addressing turbine upgrades for Units SG01, 02 and 04); Narrative for Permit Revision #4911-207-0008-V-02-7 (addressing turbine upgrade for Unit SG03). Both narratives are available on Georgia EPD's website at *http://airpermit.dnr.state.ga.us/gaairpermits/.*

[35] 40 C.F.R. § 52.21(b)(2)(i) [incorporated by reference in Georgia's SIP-approved PSD regulations at Rule 391-3-1.02(7)(a)2] defines "[m]ajor modification" as "any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(40) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(50) of this section); and a significant net emissions increase of that pollutant from the major stationary source." This definition also is incorporated into Georgia's SIP-approved NNSR rules at Georgia Rule 391-3-1-.03(8)(g)1.(ii), with some adjustments that are not relevant to this order.

[36] Under 40 C.F.R. § 52.21(a)(2)(iv)(c), which is incorporated by reference into Georgia's SIP-approved PSD regulations at Rule 391-3-1.02(7)(a)3 , the "actual-to-projected actual" applicability test for projects that involve existing emissions units is as follows: "A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions . . . and the baseline actual emissions, for each existing emissions unit, equals or exceeds the significant amount for that pollutant." Georgia's SIP-approved NNSR rules at Georgia Rule 391-3-1-.03(8)(g)2. incorporate by reference the same language.

NNSR requirements applied to its Turbine Upgrade Project.[37] Under this test, the "baseline actual emissions" for each emission unit to be modified are subtracted from the unit's "projected actual emissions" (determined based on projected emissions after the unit resumes regular operations following the project's completion). The emissions change from any emission units for which the "actual-to-projected-actual" calculation shows an increase are then summed to determine the project's overall projected emissions increase. This sum is compared to the appropriate "significant emissions rate" for each pollutant. For all pollutants that have a "significant emissions increase," the PSD/NNSR applicability analysis goes forward to Step Two, where the "significant net emissions increase" is determined.

Georgia's SIP-approved PSD and NNSR regulations contain definitions for "baseline actual emissions" and "projected actual emissions," which include a basic definition and several required "adjustments" for each of these calculations. The definition that is most relevant here is that "projected actual emissions" is defined at its base as "the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the five years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity ...."[38]

For Plant Scherer's Turbine Upgrade Projects[39], Georgia Power (and in turn Georgia EPD) based "projected actual emissions" on the maximum annual rate at which the affected emissions unit is projected to emit a regulated NSR pollutant in any one of the 10 years (12-month period) following the date the unit resumes regular operation after the project, consistent with the regulations cited above.[40] As noted above, this emissions projection included consideration of the effect of pollution controls installed pursuant to Georgia Rules (uuu) and (sss).

In determining a unit's "projected actual emissions," the existence of pollution controls on a unit is considered part of the unit's operational capabilities; therefore, the anticipated effect of the controls on the unit's post-project emissions can be considered if the controls will be installed and operating during the time period selected for the emissions calculation. The "projected actual emissions" calculation is a prediction of the unit's future emissions and is not meant to become an enforceable limit. *See* Letter from Stephen Page, EPA, to David Isaacs, Semiconductor Industry Assn., dated August 26, 2011 at 9 ("[W]hen calculating projected actual emissions, in addition to considering legally enforceable restrictions, owners or operators may consider the effect on emissions of design or operational parameters, including air pollution control equipment, that are not enforceable."). This is consistent with the EPA's statement in the preamble to the EPA's 2002 revisions to its NSR regulations, which confirms that the EPA was not requiring that a source's projected actual emissions become an enforceable limit.

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[37] *See* Plant Scherer RTC at 5.

[38] Georgia's SIP-approved PSD regulations define "Baseline actual emissions" at Georgia Rule 391-3-1.02(7)(a)2.(i) and "Projected actual emissions" at Georgia Rule 391-3-1.02(7)(a)2.(ii). Georgia's SIP-approved NNSR regulations at Georgia Rule 391-3-1-.03(8)(g)1 incorporate these same definitions.

[39] *See* page 7-8 of the Background Section of the Order, which describes the dates of the turbine upgrades and the installation of required controls.

[40] *See* Letter from Georgia Power to Georgia EPD dated October 23, 2009 for Unit SG03 (supplement to application for permit amendment # 4911-207-0008-V-02-7, submitted in response to Georgia EPD request for additional information); Letter from Georgia Power to Georgia EPD dated November 17, 2009 for Unit SG02 (supplement to application for permit amendment # 4911-207-0008-V-02-A, submitted in response to Georgia EPD request for additional information); *see also* Permit 4911-207-0008-V-03-0, at 39-40, Conditions 6.2.20 and 6.2.21 (for all four units, requiring Georgia Power to calculate and maintain a record of annual emissions for a period of ten years following resumption of regular operations after installation of the upgraded steam turbines and control equipment, and requiring retention records associated with the initial PSD/NNSR non-applicability determination for 15 years following resumption of regular operations after the changes.).

67 Fed. Reg. 80186, 80197 (Dec. 31, 2002). There, the EPA explained that rather than making the unit's projected actual emissions an enforceable limit, a facility's projected actual emissions must be tracked against the facility's actual post-change emissions for five years following resumption of regular operations (or ten years if one of the effects of the physical or operational change is to increase a unit's design capacity or potential to emit), if there is a reasonable possibility that a project will cause a significant emissions increase. *Id.* at 80192. This directly refutes the Petitioners' assertions that Georgia EPD "improperly required additional reporting on the emissions once the project is complete, which is irrelevant to the pre-construction analysis" (Scherer Petition at 8) and that Georgia EPD's reliance on monitoring to confirm the accuracy of Georgia Power's emissions projection was "incorrect under the PSD regulations" (Scherer Petition at 9).[41] To the contrary, this is the way the EPA's NSR regulations are intended to work. The permit record indicates that Plant Scherer's turbine upgrades and the installation of pollution controls to comply with Georgia Rule (sss) are changes to the same emission unit (*i.e.*, the boiler/steam turbine or EUSGU). The record further indicates that Georgia Power planned to undertake the turbine upgrades and pollution control installation as part of the same renovation project during the same shutdown period, and that the controls will be installed and operating when the source resumes regular operation after the project's completion.[42] The Petitioners offer nothing rebutting information in the permit record indicating that the controls will be installed and operating during the time period selected by Georgia Power for use in its "projected actual emissions" calculation.[43] The Petitioners provided no additional demonstration concerning the NNSR applicability review for PM and SO_2 emissions related to this claim. Thus, I find that the Petitioners did not demonstrate that it was inappropriate for Georgia Power to consider the emission reductions anticipated from the installation of controls in calculating the units' "projected actual emissions" under Step One of the PSD/NNSR applicability analysis.[44] For the foregoing reasons, I deny the petition on these issues.

2. Georgia Power Cannot Take Credit for Emission Decreases Associated with Georgia Rules (sss) and (uuu) in Determining Whether the Project Will Cause a Net Emissions Increase under Step Two of the PSD/NNSR Applicability Analysis.

Petitioners' Claim. The Petitioners contend that if Georgia Power took credit for decreases associated with Rules (sss) and (uuu) in determining the project's net emissions increase under Step Two of the PSD/NNSR applicability analysis, this was improper because neither rule is enforceable during periods of allowable excess emissions and there is no requirement for continuous monitoring during such

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[41] In response to comments on the draft Plant Scherer permit, Georgia EPD explained that to address the commenters' concerns, "the Division has added Conditions 6.2.20, 6.2.21 and 6.2.22 to require record keeping and reporting of actual emissions that are pertinent to this modification (i.e., the turbine upgrade projects for Units 1, 2, 3 and 4) in accordance with Georgia Rule 391-3-1-.02(7)(b)15.(i)." Scherer Response to Comments, Permit Narrative Addendum at 5. Georgia EPD explained: "These conditions will require the facility to record, maintain and report actual emissions that are pertinent to this modification that justify avoidance of NSR/PSD review and document accuracy of the baseline-actual-to-projected-actual emissions calculations and explain any increases reported." *Id.*

[42] *See* pages 7-8 of the Background Section of this Order.

[43] Petitioners argue that it is not clear whether the emission limits (and control requirements) in Georgia Rules (uuu) and (sss) will be in effect at the time that construction begins (Plant Scherer Petition at 10), but do not dispute that the emission controls will be in effect during the time period following resumption of regular operations that Georgia Power selected for use in the "project actual emissions" determination.

[44] In the section of the Scherer Petition addressing the appropriateness of considering the controls in Step Two of the PSD/NNSR analysis, Petitioners contended that "it is not clear that such limits were or will be in effect 'at and after the time that actual construction on the particular change begins.'" Scherer Petition at 10. This argument does not apply to consideration of the controls in Step One of the analysis, which does not depend on an emission limit being in effect at the time that construction begins but instead turns on whether the controls will be installed and operating as of "the date the unit resumes regular operation after the project." *See* Georgia Rule 391-3-1.02(7)(a)2.(ii) (PSD definition of "projected actual emissions") and Georgia Rule 391-3-1-.03(8)(g)1 (NNSR incorporation by reference of PSD definition).

episodes, and it is not clear that such limits were or will be in effect "at and after the time that actual construction on the particular change begins." Scherer Petition at 10.

EPA's Response. Petitioners' claim does not demonstrate that the permit is not in compliance with the Act. Georgia EPD's determination that the turbine upgrades are not subject to PSD/NNSR was based solely on Georgia EPD's conclusion under Step One of the required analysis that the project will not result in a significant emissions increase. Furthermore, as discussed above, I deny the Petitioners' claims regarding deficiencies in Step One of the analysis. Thus, Petitioners' arguments regarding whether it would be appropriate to consider emission reductions associated with compliance with Georgia Rules (uuu) and (sss) under Step Two of the analysis are irrelevant to the applicability determination. The Petitioners provided no additional demonstration concerning the NNSR applicability review for PM and SO_2 emissions related to this claim. Therefore, I deny the Petitioners' request for an objection to the permit on this claim.

V. CONCLUSION

For the reasons set forth above and pursuant to CAA § 505(b)(2) and 40 C.F.R. § 70.8(d), I hereby grant in part and deny in part the Petitioners' five petitions seeking the EPA's objection to the title V operating permits issued by Georgia EPD for Plants Hammond, Kraft, McIntosh, Wansley and Scherer. I further order actions consistent with 42 U.S.C. § 7661d(e) and 40 C.F.R. § 70.7(g), as described in Section IV, Claim 2.

Dated: APR 14 2014

Gina McCarthy,
Administrator

EXHIBIT D

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
999 18TH STREET - SUITE 500
DENVER, CO 80202-2466
http://www.epa.gov/region08

JUL 19 1999

Ref: 8P-AR

Mr. Ed Kurip, Director
Air Quality Management
Ute Indian Tribe
P.O. Box 279
Ft. Duchesne, Utah 84026

Mr. Rusty Ruby, Manager
Operating Permits Section
Utah Division of Air Quality
P.O. Box 144820
Salt Lake City, Utah 84114-4820

Re: 40 CFR Part 71 Sources on Uintah and Ouray Reservation

Dear Mr. Kurip and Mr. Ruby:

This is concerning each of your responses to my June 1999 request for identification of jurisdictional authority (Tribe/EPA or State) for air pollution sources located within the exterior boundaries of the Uintah and Ouray Indian Reservation. Enclosed are the June 23, 1999 response from Rusty Ruby with the State of Utah's conclusions on jurisdictional authority and the July 15, 1999 response from Ed Kurip with the Ute Indian Tribe's conclusions on jurisdictional authority. Also enclosed is a revised Table 1 – Reservation Land Source Summary (dated 7/16/99), that is based on the Tribe's and State's conclusions for jurisdictional authority.

Region VIII intends to use the revised Table 1 in determining which air pollution sources may be subject to the federal operating permits program (part 71), the pre-construction Prevention of Significant Deterioration Program (PSD), and other applicable federal programs.

If either of you have any questions concerning this correspondence, please feel free to contact me at (303) 312-6936.

Sincerely,

Monica S. Morales

Monica S. Morales
Air & Radiation Program

Printed on Recycled Paper

Enclosures (3)

cc: Tod J. Smith (Whiteing & Smith, w/enclosures)
Fred Nelson (UT - AG Office, w/enclosures)
Elaine Willie (Env. Coordinator, Ute Indian Tribe, w/enclosures)

Revised 7/16/99

Table 1 -- Reservation Land Source Summary

	Company	Site	Location	TSP tons/yr	PM_{10} tons/yr	NO_x tons/yr	CO tons/yr	SO_2 tons/yr	VOC tons/yr	Title V
Tribe/EPA	American Gilsonite Co	Bonanza Mines	40°01'04" lat 109°10'17" long Zone 12	24.98	16.10	3.00	0.60		241.00	yes
State	ANR Production Co	East Field Compressor Station	40°21'19" lat 110°14'46" long Zone 12			171.41	21.78		0.10	yes
State	ANR Production Co	Main Gas Processing Plant	40°21'28" lat 110°19'38" long Zone 12		0.10	283.88	36.90		0.20	yes
State	ANR Production Co	South Field Compressor Station	40°16'19" lat 110°26'06" long Zone 12			134.27	17.08		0.10	yes
State	ANR Production Co	West Field Compressor Station	40°19'06" lat 110°23'41" long Zone 12			119.98	15.27		0.10	yes
Tribe/EPA	Apache Corp	Compressor Station	39°54'56" lat 109°43'50" long Zone 12	0.04	0.04	12.17	5.41	0.01	2.16	
State	Burdick Paving Co	Madsen Hot Plant	N Airport Road, Roosevelt		6.01	0.48	0.50	3.86	0.37	yes NSPS[2]
Tribe/EPA	Chevron USA Production Co	Red Wash Field	40°15'00" lat 109°20'00" long Zone 12		1.25	255.68	44.54	24.61	85.66	yes NSPS[3]
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Prospect Well #33-3-5	40°15'13" lat 109°33'28" long Zone 12	0.12	0.12	7.5	1.04 CO2 469.6	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Prospect Well Alta #5-1-B	40°14'45" lat 109°34'36" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Prospect Well Alta #5-1-B	40°14'45" lat 109°34'36" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Prospect Well Alta #5-2-C	40°14'46" lat 109°34'55" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Federal Well #33-7-L	40°15'8" lat 109°33'58" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Federal Well #33-8-N	40°14'8" lat 109°33'58" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Columbia Gas Development	Horseshoe Bend Prospect Fed. Well #33-6-F	40°15'23" lat 109°33'32" long Zone 12		0.12	7.5	1.04	0.002	4.02	
Tribe/EPA	Deseret Generation & Transmission	Bonanza	T 8 S, R 23 E Section 26 Zone 12	369.88	326.94	6,336.6	44.25	631.81	83.11	yes
Tribe/EPA	Enron Oil & Gas Co	Old Squaw Crossing Compressor Station	39°55'20" lat 109°45'13" long Zone 12							

[2] NSPS = New Source Performance Standards -- 40 CFR Part 60
[3] NSPS = New Source Performance Standards -- 40 CFR Part 60

Table 1 -- Reservation Land Source Summary (con't)

	Company	Site	Location	TSP tons/yr	PM_{10} tons/yr	NO_x tons/yr	CO tons/yr	SO_2 tons/yr	VOC tons/yr	Title V
Tribe/EPA	Exxon Co, USA	Walker Hollow Unit - Tank Battery #1	40°13'10" lat 109°14'33" long Zone 12	0.06	42.05	11.15	1.57	0.26	1.88	no
Tribe/EPA	Exxon Co, USA	Walker Hollow Unit - Tank Battery #2	40°13'08" lat 109°16'19" long Zone 12	0.16	0.14	3.29	0.69	0.56	3.02	no
Tribe/EPA	Exxon Co, USA	Walker Hollow Unit - Tank Battery #3	40°10'41" lat 109°18'41" long Zone 12	0.01	0.01	0.25	0.05		12.70	no
Tribe/EPA	Exxon Co, USA	Walker Hollow Unit Satellite Tank Battery	40°14'06" lat 109°16'49" long Zone 12	0.01	0.01	5.10	0.68	0.00	1.75	no
State	Gary-Williams Energy Corp	Altonah Gas Plant	T 2 S, R 3 W Section 5 Zone 12	0.10	0.10	4.76	1.19	0.02	0.24	yes Part 70[4]
State	Gary-Williams Energy Corp	Bluebell Gas Plant	40°23'00" lat 110°05'00" long Zone 12	125.30	61.30	566.72	101.56	0.14	29.47	yes
State	**Koch Hydrocarbon Co***	Cedar Rim Gas Plant	T 3 S, R 6 W Section 21 Zone 12		0.14	108.69	43.46		4.75	yes
State	Pennzoil Products Co	Roosevelt Refinery	40°16'49" lat 110°01'07" long Zone 12	36.03	12.98	233.52	439.28	85.03	653.40	yes
Tribe/EPA	PG&E Resources Co	Riverbend Compressor Station	39°57'07" lat 109°45'11" long Zone 12							
Tribe/EPA	PG&E Resources Co	Riverbend Well Site	40°06'03" lat 109°42'25" long Zone 12							
Tribe/EPA	PG&E Resources Co	Willowcreek Gas Injection Project	40°0'37" lat 109°44'36" long Zone 12			16.2	24.2		8.1	no
Tribe/EPA	CNG Producing Co	Riverbend Field	40°02'00" lat 109°40'00" long Zone 12	1.23	936.00	229.97	8.44	0.07	274.48	yes
Tribe/EPA	Questar Pipeline Co	Fidlar Main Line Station	40°02'02" lat 109°26'49" long Zone 12			164.60	27.89	0.04		yes
Tribe/EPA	Wexpro Co	Wexpro Island Unit	39°54'00" lat 109°42'00" long Zone 12	0.01		0.80	0.16		0.04	no
Tribe/EPA	Williams Field Services	Duck Creek Compressor Station	T 9 S, R 20 E Section 23 Zone 12			30.04	3.80		1.24	no

* Koch Hydrocarbon Co. has been sold. New owner is unknown at this time.

[4] Part 70 = Operating Permits Program -- 40 CFR Part 70

EXHIBIT E

State of Utah

DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF AIR QUALITY

Michael O. Leavitt
Governor

Dianne R. Nielson, Ph.D.
Executive Director

Ursula K. Trueman
Director

150 North 1950 West
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Salt Lake City, Utah 84114-4820
(801) 536-4000 Voice
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(801) 536-4414 T.D.D.

DAQE-086-98

January 30, 1998

Howard L. Vickers
Deseret Generation & Transmission
12500 East 25500 South
Vernal, Utah 84078

Dear Mr. Vickers:

Re: Intent to Approve Modification of Bonanza One (1) Power Plant Emission Limits, Change in Coal Pile Parameters, and Ruggedized Rotor Project, Uintah County, CDS-A1, NSPS, NESHAP, Title V

The attached document is an Intent to Approve for the above referenced project.

Future correspondence on this Approval Order should include the engineer's name as well as the DAQE number as shown on the upper right-hand corner of this letter. Please direct any technical questions you may have on this project to Mr. Tim Blanchard. He may be reached at (801) 536-4057.

Sincerely,

Lynn R. Menlove, Manager
New Source Review Section

LRM:JTB:cmn

cc: Uintah Basin District Health Department
Mike Owens, EPA Region VIII

STATE OF UTAH

Department of Environmental Quality

Division of Air Quality

INTENT TO APPROVE MODIFICATION OF BONANZA ONE (1) POWER PLANT EMISSION LIMITS, CHANGE IN COAL PILE PARAMETERS, AND RUGGEDIZED ROTOR PROJECT

Prepared By: Tim Blanchard, Engineer

INTENT TO APPROVE NUMBER

DAQE-086-98

Date: January 30, 1998

Source

Deseret Generation & Transmission

Ursula K. Trueman
Executive Secretary
Utah Air Quality Board

Abstract

Deseret Generation & Transmission Co-operative. (DG&T) is proposing to modify Approval Order (AO) DAQE-706-97 (dated August 4, 1997) by modifying certain emission limits, modifying the Coal Pile parameters, and installing a ruggedized rotor at the Bonanza Power Plant Unit One (1) located in Uintah County. Uintah County is an attainment area for all pollutants. New Source Performance Standards (NSPS) Subparts A and Da apply to this source. National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations do not apply to this source. DG&T is requesting a modification in federally enforceable emission limits which will limit the potential to emit (PTE) for this source. These emission limits are being imposed to demonstrate that any net increase in emissions from the approved facilities will not exceed the threshold emission levels which trigger additional review under state New Source Review (NSR) and Prevention of Significant Deterioration (PSD) programs. Because of the increased capacity of the Turbine Generator to handle steam flow, there will be a net increase in certain emissions resulting from an overall increase in the heat input to the Boiler from 4381 MMBtu's/Hr to 4578 MMBtu's/Hr. DG&T also proposes to increase the total area of the coal pile to 22 acres and the active reclaim area to 11 acres. The net effect of these projects will be an overall reduction of Bonanza 1's potential emissions, with a significant reduction in NO_x emissions and relatively minor increases in other emissions. DG&T proposes to reduce its potential NO_x emissions by 528.17 TPY and increase the following emissions: particulate emissions 22.60 TPY, PM_{10} 14.11 TPY, SO_2 38.21 TPY, CO 91.60 TPY, VOC 10.68 TPY. A 30-day public comment period is required for DG&T's proposal.

The Notice of Intent for the above-referenced project has been evaluated and has been found to be consistent with the requirements of the Utah Air Quality Rules (UAQR) and the Utah Air Conservation Act. Air pollution producing sources and/or their air control facilities may not be constructed, installed, established, or modified prior to the issuance of an Approval Order (AO) by the Executive Secretary of the Utah Air Quality Board.

A Notice of Intent to issue an AO will be published in the Vernal Express on February 4, 1998. A 30-day period following the publishing date will be allowed during which the proposal and evaluation of its impact on air quality will be available for both you and the public to review and comment. If anyone so requests within 15 days of publication of the notice, a hearing will be held. The hearing will be held as close as practicable to the location of the source. Any comments received during the 30-day period and the hearing, if held, will be evaluated.

Please review the proposed AO conditions during this period and make any comments you may have before its closure. The proposed conditions of the AO may be changed as a result of the comments received. Unless changed, the AO will be based upon the following conditions:

General conditions:

1. This AO applies to the following company:

   HOME OFFICE:

   Deseret Generation & Transmission Co-Operative
   5295 South 300 West, Suite 500
   Murray, Utah 84107
   PHONE NUMBER: 801-892-6500
   FAX NUMBER: 801-892-6599

The equipment listed below in this AO shall be operated at the following location:

PLANT LOCATION:

Bonanza Power Station Unit 1
12 kilometers northwest of Bonanza, Utah
Uintah County

Universal Transverse Mercator (UTM) Coordinate System:
4,438,606 meters Northing, 646,206 meters Easting

2. Definitions of terms, abbreviations, and references used in this AO conform to those used in the Utah Air Conservation Rules (UACR), Utah Administrative Codes (UAC), New Source Performance Standards (NSPS) and Series 40 of the Code of Federal Regulations (40 CFR). These definitions take precedence unless specifically defined otherwise herein.

3. Deseret Generation & Transmission (DG&T) shall operate the 500 est. Megawatt (MW) gross Bonanza Power Station Unit 1 according to the terms and conditions of this Approval Order as requested in the Notice of Intent dated December 24, 1997 and additional information submitted January 5, 1998.

4. At least once per calendar year, all employees who operate equipment (operator) that produces and/or controls emissions to the air shall receive proper training as to their responsibilities in operating that equipment according to all relevant conditions of this AO. The training for each operator shall be for all equipment that operator operates. The equipment shall include all of the associated equipment listed in Conditions # 7, 8, and 9. Within 60 days of every time this AO is modified or reissued, those employees who operate equipment that produces and/or controls emissions to the air that is affected by the AO changes shall receive proper training as to their responsibilities in operating equipment according to all relevant conditions of this AO. Within 60 days of a new operator being employed or assigned with the job responsibility to operate any of the equipment that produces and/or controls emissions to the air, the new operator shall receive proper training as to their responsibilities in operating the equipment according to all relevant conditions of this AO. Records of operator training shall be made available to the executive secretary or executive secretary's representative upon request and the records shall include the two-year period prior to the date of the request. This AO shall be made available to all employees who operate the equipment listed in this AO.

5. The approved installations shall consist of a 500 est. MW coal fired steam electric generating station and associated equipment.

6. This AO shall replace the AO DAQE-706-97 dated August 4, 1997.

Limitations and tests procedures

7. Sulfur Emission Control

A. Bonanza 1 shall not discharge to the atmosphere sulfur as SO_2 at a rate exceeding 0.0976 lb/MMBTU heat input over a rolling 12-month average. Compliance with this emission limitation shall be based on CEM data and fuel heat input. Compliance shall be determined by calculating the rolling 12-month average. On the first day of each month a new 12-month average shall be calculated using data from the previous 12 months.

B. Bonanza 1 shall achieve at least 90% SO_2 removal efficiency based on a 30-day rolling average.

C. Bonanza 1 SO_2 emissions shall not exceed 0.15 lb/MMBTU heat input as averaged over 30 successive boiler operating days.

D. To achieve the limits above, DG&T may use scrubber slurry additives (such as adipic acid etc.) to increase the dissolved alkalinity of the slurry reagent used in the FGD scrubber.

E. Compliance with the SO_2 removal requirements shall be based on data from outlet SO_2 continuous emissions monitors (CEM), and either inlet SO_2 data from CEM or coal analysis data, over a 30-day rolling average. The total percent removal may be computed using the total available sulfur from the coal analysis and overall sulfur removal. Compliance shall be determined by calculating the arithmetic average for all valid hourly emissions rates for SO_2 for the 30 successive boiler operating days.

8. Nitrogen Oxides Emission Control

A. Bonanza 1 shall not discharge to the atmosphere nitrogen oxide (NO_x) at a rate exceeding 0.50 lb/MMBTU heat input on an annual average. Compliance with this emission limitation shall be determined in accordance with 40 CFR 76.5(b).

B. Bonanza 1 shall not discharge to the atmosphere nitrogen oxide (NO_x) at a rate exceeding 0.55 lb NO_x/MMBTU heat input as a 30-day rolling average value averaged over 30 successive boiler operating days. Compliance with this emission limitation shall be based on CEM data and fuel heat input. Compliance shall be determined by calculating the arithmetic average of all valid hourly emission rates (at least two values each hour are required) for NO_x for 30 successive boiler operating days.

9. Particulate and PM_{10} Emission Control

A. Unit No. 1 shall not discharge to the atmosphere particulate matter at a rate exceeding 0.0297 lbs/MMBTU BTU heat input as determined by 40 CFR 60, Appendix A, Methods 1-5 and 19.

B. Unit No. 1 shall not discharge to the atmosphere PM_{10} particulate matter at a rate exceeding 0.0286 lbs/MMBTU heat input as determined by 40 CFR 60, Appendix A, Methods 1, 2, 4, 5-5e and 19.

C. Visible emissions from any source shall not exceed 20% opacity as determined primarily by CEM equipment, except for one six-minute period per hour of not more than 27% opacity for the tall stack, as determined by CEM equipment. However, EPA Method 9 may be used when the opacity CEM equipment is not operating.

D. Dust collectors DC-1 through 5, LDC 1 and 2, and the fly ash silo dust collector shall be maintained and operated per manufacturer's recommendations.

10. Stack testing to show compliance with the emission limitations stated in the above condition shall be performed as specified below:

A.

Emission Point	Pollutant	Testing Status	Test Frequency
Unit No. 1			
600 foot stack	TSP	*	@
	PM_{10}	*	@
	SO_2	*	@
	NO_x	*	@
DC-4 and DC-5	PM_{10}	**	#

B. Testing Status (To be applied above)

* Compliance testing is required. The initial testing shall be done in 1995. Alternatively, data from testing done in conjunction with the installation, calibration and certification of the new CEM system in 1994 may be used.

** No initial testing is required. However, the Executive Secretary may require testing at any time in accordance with R307-1-3.4.1, UAC. The source shall be tested if directed by the Executive Secretary.

\# Test if directed by the Executive Secretary. Tests may be required if the source is suspected to be in violation with other conditions of this AO.

@ Test every five (5) years

C. Notification

The applicant shall provide a notification of the test date at least 30 days before the test. A pretest conference shall be held if directed by the Executive Secretary. It shall be held at least 30 days before the test between the owner/operator, the tester, and the Executive Secretary. The emission point shall be designed to conform to the requirements of 40 CFR 60, Appendix A, Method 1, and Occupational Safety and Health Administration (OSHA) or Mine Safety and Health Administration (MSHA) approvable access shall be provided to the test location.

D. TSP

40 CFR 60. Appendix A, Method 5

E. PM_{10}

For stacks in which liquid drops are present, methods to eliminate the liquid drops should be explored. If no reasonable method to eliminate the drops exists, then the following methods shall be used: 40 CFR 60, Appendix A, Method 5, 5A, 5D, or 5E as appropriate. The back half condensibles shall also be tested using the method specified by the Executive Secretary. The portion of the front half of the catch considered PM_{10} shall be based on information in AP-42, Appendix C or other data acceptable to the Executive Secretary.

The back half condensibles shall not be used for compliance demonstration but shall be used for inventory purposes.

F. Sample Location

40 CFR 60. Appendix A, Method 1

G. Volumetric Flow Rate

40 CFR 60, Appendix A, Method 2 or any alternative method that has the approval of UDAQ or EPA.

H. Sulfur Dioxide (SO_2)

40 CFR 60, Appendix A, Method 6, 6A, 6B or 6C

I. Nitrogen Oxides (NO_x)

40 CFR 60, Appendix A, Method 7, 7A, 7B, 7C, 7D or 7E

J. Determination of Sulfur Dioxide Removal Efficiency and Particulate Matter, Sulfur Dioxide and Nitrogen Oxides Emissions Rates

40 CFR 60, Appendix A, Method 19

K. Calculations

To determine mass emission rates (lbs/hr, etc.), the pollutant concentration as determined by the appropriate methods above shall be multiplied by the volumetric flow rate and any necessary conversion factors determined by the Executive Secretary to give the results in the specified units of the emission limitation.

L. Existing Source Operation

For an existing source/emission point, the production rate during all compliance testing shall be no less than 90% of the maximum capacity unless approved by the Executive Secretary.

Roads and Fugitives

11. Coal and limestone conveyors shall be enclosed and all drop points shall be vented to fabric dust collectors.

12. The track hopper for bottom dump coal cars shall have water sprays in place. The water spray shall be used during dumping when conditions warrant. Conditions which warrant operation of the sprays are defined as any time the 20% opacity limitation is in jeopardy of being violated. To ensure that the sprays are always operative, the equipment shall be tested at least once per month, except when whether conditions prohibit. A log of testing and operation shall be kept. The log shall include:

    A. Times of testing.
    B. Times of coal deliveries
    C. Times of spray operation
    D. Weather conditions at time of coal deliveries
    E. Coal conditions (washed, unwashed, dry, moist, etc.)

13. The coal pile shall not exceed 22 acres in total area. The active reclaim area shall not exceed 11 acres at any one time. The reclaim area may be moved to any location on the coal pile. The remainder of the coal pile shall be the long-term storage area. Emissions of particulate from the long-term storage area shall be controlled by compaction of the coal pile surface and sealing with a surfactant initially and by subsequent application of sealing agent as warranted. A surfactant and spray mechanism to apply it shall be available and operative at all times. Conditions which warrant application of the surfactant are defined as any time the 20% opacity limitation is in jeopardy of being violated. A log of operation shall be kept. The log shall include:

    A. Times of spray operation
    B. Compaction operation
    C. Weather conditions
    D. Surface conditions (dry, crumbled, moist, etc.)

14. The long term limestone storage shall be sealed with a surfactant as dry conditions warrant or as determined necessary by the Executive Secretary.

15. The limestone receiving hopper shall be partly enclosed with a wind break.

16. The fly ash/FGD sludge mixture at the end of the conveyor and prior to being completely covered in accordance with landfill procedures, shall be water sprayed to minimize fugitive emissions as conditions warrant.

A record/log of stabilizing done shall be kept which includes dates, type of stabilizing agent, amount applied, and area of application.

17. All unpaved roads and other unpaved operational areas that are used by mobile equipment shall be water sprayed and/or chemically treated to control fugitive dust. The application of water or chemical treatment shall be used. Treatment shall be of sufficient frequency and quantity to maintain the surface material in a damp/moist condition. The opacity shall not exceed 20% during all times the areas are in use or unless it is below freezing. If chemical treatment is to be used, the plan must be approved by the Executive Secretary. Records of water treatment shall be kept for all periods when the plant is in operation. The records shall include the following items:

    A. Date
    B. Number of treatments made, dilution ratio, and quantity
    C. Rainfall received, if any, and approximate amount
    D. Time of day treatments were made

    Records of treatment shall be made available to the Executive Secretary upon request and shall include a period of two years ending with the date of the request.

18. Visible emissions from haul-road traffic and mobile equipment in operational areas shall be controlled by use of a dust control plan.

Fuels

19. DG&T shall use only coal and/or natural gas as a primary fuel and fuel oil and/or natural gas during startup, shut down, upset conditions and flame stabilization. DG&T may burn on-spec used oil, off-spec used oil and small quantities of self generated hazardous waste (<850 gallons/month) as specified in State and Federal regulations. If any other fuel is to be used, an AO shall be required in accordance with R307-1-3.1, UAC.

20. The sulfur content of any fuel oil or diesel burned shall not exceed 0.5 percent by weight. Sulfur content shall be decided by ASTM Method D-4294-89, or approved equivalent. The sulfur content shall be tested if directed by the executive secretary.

21. Boilers burning used oil for energy recovery shall comply with the following:

    A. The concentration/parameters of contaminants in the used oil shall not exceed the following levels:

1.	Arsenic	5	ppm by weight
2.	Cadmium	2	ppm by weight
3.	Chromium	10	ppm by weight
4.	Lead	100	ppm by weight
5.	Total halogens	1,000	ppm by weight
6.	Sulfur	0.5	percent by weight

B. The flash point of all used oil to be burned shall not be less than 100 °F.

C. The owner/operator shall provide test certification for each load of used oil received. Certification shall be either by their own testing or test reports from the used oil fuel marketer. Records of used oil fuel consumption and the test reports shall be kept for all periods when the plant is in operation. Records shall be made available to the executive secretary or her representative upon request. The records shall include a period of three years ending with the date of the request.

D. Used oil (off-spec) that does exceed any of the listed contaminants content may be burned, but owner/operator shall notify the Division of Solid and Hazardous Waste and EPA. The owner/operator shall record the quantities of used oil burned on a daily basis.

E. Used oil that contains more than 1000 ppm by weight of total halogens shall be considered a hazardous waste and can be burned at a maximum rate of 850 gallons/month. The used oil shall be tested for halogen content by ASTM Method D-808-81, EPA Method 8240 or Method 8260 before used oil fuel is transferred to the boiler fuel tank and burned. Small quantities self generated hazardous used fuels are regulated by 40 CFR 266.108(a) "Small Quantity On-site Burner Exemptions".

F. Sources utilizing used oil as a fuel shall comply with the State Division of Solid and Hazardous Waste in accordance with R315-15, UAC "Used Oil Management Rule".

Federal Limitations and Requirements

22. In addition to the requirements of this AO, all provisions of 40 CFR 60, NSPS Subparts A and Da, 40 CFR 60.40a to 60.49a (Standards of Performance for opacity, SO_2, and NO_x) apply to this installation.

Monitoring - General Process

23. All air quality monitoring must conform to the requirements of 40 CFR, Part 58. As part of the air quality monitoring program, a quality control program shall be used and it shall consist of policies, procedures, specifications, standards, and documentation necessary to:

    A. Meet the monitoring objective and quality assurance requirements of the Executive Secretary.

    B. Minimize loss of air quality data due to malfunction or out of control conditions.

24. The owner/operator shall install, calibrate, maintain, and operate a continuous emissions monitoring (CEM) system on the 600 foot stack. The owner/operator shall record the output of the system, for measuring the opacity of emissions, the SO_2 emissions, the NO_x emissions, and diluent. Procedures to be followed for (1) testing, monitoring, and reporting of excess emissions of particulates, opacity, sulfur dioxide and nitrogen oxides, and for (2) the purpose of demonstrating compliance with the emission limitations of Conditions (7), (8), and (9) are

specified in the applicable section of 40 CFR 60.7, 60.8, 60.11, 60.13, Subpart Da, Appendix A, Methods 1-7, Appendix B, Performance Specifications 1, 2, and 3, Appendix F, and the state CEM policy document (all applicable sections of R307-1-4.6, UAC).

25. A quality control/assurance plan/manual for the continuous monitoring system shall be developed and implemented. As a minimum, the quality control program shall have written procedures for each of the following activities:

    A. Installation of CEM's
    B. Calibration of CEM's
    C. Zero and calibration checks and adjustments for CEM's
    D. Preventive maintenance for CEM's (including parts inventory)
    E. Data recording and reporting
    F. Program of corrective action for inoperable CEM's
    G. Annual evaluation of CEM system

Records & Miscellaneous

26. All installations and facilities authorized by this AO shall be adequately and properly maintained. All pollution control vendor recommended equipment shall be installed, maintained, and operated. Instructions from the vendor or established maintenance practices that maximize pollution control shall be used. All necessary equipment control and operating devices, such as pressure gauges, amp meters, volt meters, flow rate indicators, temperature gauges, CEMs, etc., shall be installed and operated properly and easily accessible to compliance inspectors. A copy of all manufacturers' operating instruction for pollution control equipment and pollution emitting equipment shall be kept on site. These instructions shall be available to all employees who operate the equipment and shall be made available to compliance inspectors upon their request.

27. The owner/operator shall comply with R307-1-3.5, UAC. This rule addresses emission inventory reporting requirements.

28. The owner/operator shall comply with R307-1-4.7, UAC. This rule addresses unavoidable breakdown reporting requirements. The owner/operator shall calculate/estimate the excess emissions whenever a breakdown occurs. The total of excess emissions shall be reported to the Executive Secretary as directed for each calendar year.

All records referenced in this AO or in applicable NSPS or NESHAP, which are required to be kept by the owner/operator, shall be made available to the executive secretary or her representative upon request and shall include a period of two years ending with the date of the request. All records shall be kept for a period of two years (used oil records are to be kept for a period of three years). Examples of records to be kept at this source shall include the following as applicable:

A. Test results ..... Conditions 7,8 & 9
B. Maintenance records ..... Condition 26
C. Upset, breakdown episodes ..... Condition 28
D. Fugitive emission control ..... Conditions 12, 13, 16 & 17

E. CEM records ..... Conditibn 24
F. Fuel consumption ..... Condition 21
G. Training ..... Condition 4

Any future modifications to the equipment approved by this order must also be approved in accordance with R307-1-3.1.1, UAC.

The Executive Secretary shall be notified in writing if the company is sold or changes its name. The notification shall be submitted within 30 days of such action.

This AO in no way releases the owner or operator from any liability for compliance with all other applicable federal, state, and local regulations including the Utah Air Conservation Rules.

Annual emissions for this source the entire plant are currently calculated at the following values:

	Pollutant	Tons/yr
A.	Particulate	962.56
B.	PM_{10}	925.76
C.	SO_2	1,968.11
D.	No_x	10,029.83
E.	CO	602.45
F.	VOC non methane	70.89
G.	Arsenic	0.34
H.	Beryllium	0.01
I.	Cadmium	0.07
J.	Chromium	4.00
K.	Lead	0.70
L.	Manganese	3.45
M.	Mercury	0.08
N.	Nickel	2.19

These calculations are for the purposes of determining the applicability of Prevention of Significant Deterioration, nonattainment area, and Title V source requirements of the UAC R307.

In accordance with the requirements of Title V of the 1990 Clean Air Act, the following pollutants may be subject to an operating permit fee. Emissions of the following pollutants from all sources, including pre-November 29, 1969 sources, may be subject to the operating permit fee. Both the fees rate and the class of pollutants are subject to change by State, the federal agencies, or both.

	Pollutant	Tons/yr
A.	PM_{10}	925.76
B.	SO_2	1,968.11
C.	NO_x	10,029.83
D.	VOC non methane	70.89
E.	HAPs	10.84

The Division of Air Quality is authorized to charge a fee for reimbursement of the actual costs incurred in the issuance of an AO. Unless public comments are received which require additional work, the fee for this AO will be $1,200.00. An invoice will follow. You may pay this fee prior to the end of the comment period. If there are comments or additional fees, you will be notified.

Sincerely,

Lynn R. Menlove, Manager
New Source Review Section