Appendix E – Worksheets for Major Sources of PM10, NOx and SO2

Regulation No. 1

Particulates, Smokes, Carbon Monoxide and Sulfur Oxides

Colorado Air Quality
Control Commission

Colorado Department
of Public Health
and Environment

7. Fort Carson shall maintain records of each fog oil smoke generation exercise which shall include:

   a. observations from the designated observer(s) regarding the drift of the fog oil smoke only when said smoke approaches the Installation or Site boundary to the extent that all generation must cease to prevent visible emissions from crossing the boundary;

   b. the amount of fog oil used in gal/day;

   c. the general location at which the fog oil smoke was generated; and

   d. the date and duration of the fog oil smoke generation; and

8. For purposes of this section, fog oil is defined as highly refined (hydro-treated) virgin oil.

The Commanding General in charge of Fort Carson shall be responsible for ensuring that no drift of smoke from fog oil generation or other obscurant use occurs across the boundary of the military reservations, even if generated in accordance with this section.

III. PARTICULATES

A. Fuel Burning Equipment

1. No owner or operator shall cause or permit to be emitted into the atmosphere from any fuel-burning equipment, particulate matter in the flue gases which exceeds the following:

   a. 0.5 lbs. per 10^6 BTU heat input for fuel burning equipment of less than or equal to $1x10^6$ BTU/hr. total heat input design capacity.

   b. For fuel burning equipment with designed heat inputs greater than $lx10^6$ BTU per hour, but less than or equal to $500x10^6$ BTU per hour, the following equation will be used to determine the allowable particulate emission limitation.

      $PE=O.5(FI)^{-0.26}$

      Where:

      PE = Particulate Emission in Pounds per million BTU heat input.

      FI = Fuel Input in Million BTU per hour.

   c. 0.1 lbs. per 10^6 BTU heat input for fuel burning equipment of greater than $500x10^6$ BTU per hour or more.

d. If two or more fuel burning units connect to any opening, the maximum allowable emission rate shall be calculated by summing the allowable emissions from the units being operated.

2. Exceptions

Sources and emissions subject to the emission limitation of Section V. of this regulation.

3. Performance Tests

Prior to granting of a final approval permit or amending a permit, when an emission source or control equipment is altered, or at any time when there is reason to believe that emission standards are being violated, the Division may require the owner or operator of any fuel burning equipment to conduct performance tests, as measured by EPA Methods 1-4 and the front half of EPA Method 5 (40 CFR 60.275, Appendix A, Part 60) to determine compliance with this subsection of this regulation.

B. Incinerators

1. No owner or operator of an incinerator shall operate any incinerator without a permit from the Division.

2. Standard of Performance for all incinerators other than biomedical waste incinerators.

a. In areas designated as nonattainment for particulate matter, no owner or operator of an incinerator shall cause or permit emissions of more than 0.10 grain of particulate matter per standard cubic foot. (Dry flue gas corrected to 12 percent carbon dioxide.)

b. In areas designated as attainment for particulate matter, no owner or operator of an incinerator shall cause or permit emissions of more than 0.15 grain of particulate matter per standard cubic foot. (Dry Flue gas corrected to 12 percent carbon dioxide.)

3. Performance Tests

Prior to granting a final approval permit or amending a permit, when an emission source or control equipment is altered, or at any time when there is reason to believe that emission standards are being violated, the Division may require the owner or operator of an incinerator to conduct performance tests(s) in accordance with Appendix A of Air Quality Control Commission Regulation Number 6.

4. Standard of Performance for Biomedical Waste Incinerators.

The owner or operator of an existing incinerator used for the disposal of biomedical waste shall comply with Regulation No. 6, Part B. V. Standard of Performance For New Biomedical Waste Incinerators as follows:

a. All incinerators, existing as of the effective date of Regulation 6 Part B, V., with a design capacity of 400 pounds per hour and greater must comply with the requirements of this regulation by January 1, 1990.

b. All incinerators, existing as of the effective date of Regulation 6, Part B, V., with a design capacity of less than 400 pounds per hour must comply with the requirements of this regulation as applicable by December 31, 1994; except incinerators with a design capacity of less than 200 pounds per hour shall be permitted and allowed to operate only so long as the units continue to meet the particulate and visible emission standards existing prior to the effective date of Regulation 6, Part B.V., the manufacturer's design specifications and any other applicable safety standards. (The standards existing prior to the effective date of this regulation are: a) For sources existing prior to January 30, 1979: 20% opacity and 0.10 grains of particulate matter (PM) for particulate matter non-attainment areas and 0.l5 grains of PM for PM attainment areas; b) 20% opacity and 0.10 grains of PM for sources constructed after January 30, 1979.)

C. Manufacturing Processes

1. Except as provided in paragraphs 2 and 3 of this subsection C., no owner or operator of a manufacturing process unit shall cause or permit emission of any particulate matter into the atmosphere during any consecutive sixty (60) minute period which is in excess of the following.

a. For process equipment having process weight rates of 30 tons per hour or less, the allowable emission rate shall be determined by the use of the equation:

$$PE = 3.59(P)^{0.62}$$

Where:

PE = Particulate Emission in lbs. per hour

P = Process weight rate in tons per hour

b. For process equipment having process weight rates of greater than 30 tons per hour, the allowable emission rate shall be determined by use of the equation:

$$PE = 17.31(P)^{0.16}$$

Where:

PE = Particulate Emission rate in lbs. per hour

P = Process weight rate in tons per hour

c. If two or more process units are connected to the same opening, the maximum allowable emission rate shall be computed by summing the allowable emissions for the units being operated.

2. Alfalfa Dehydration Plant Drum Dryers

New alfalfa dehydration plants shall be subject to the provisions of III.C. of this regulation for process weight rates.

3. Exceptions

a. Sources and emissions subject to the emission limitations of Section V. of this regulation.

b. Fugitive dust and fugitive particulate emissions as defined in Section II.A.8 of this Regulation.

4. Performance Tests: prior to granting of a final approval permit or amending a permit, when an emission source or control equipment is altered, or at any time when there is reason to believe that emission standards are being violated, the Division may require the owner or operator of any manufacturing process to conduct performance tests, as measured by EPA Methods 1-4 and the front half of EPA Method 5 (40 CFR 60.275, Appendix A, Part 60) to determine compliance with this subsection of this regulation.

D. Fugitive Particulate Emissions

1. General Requirements

a. Existing Sources

(i) Every owner or operator of a source or activity which is subject to this Section III.D. shall employ such control measures and operating procedures as are necessary to minimize fugitive particulate emissions into the atmosphere through the use of all available practical methods which are technologically feasible and economically reasonable and which reduce, prevent and control emissions so as to facilitate the achievement of the maximum practical degree of air purity in every portion of the State.

(ii) In determining what control methods are available, practical, economically reasonable and technologically feasible, the following factors shall be considered: effects on the health, welfare (as defined in Section I.G. of the Common Provisions regulation), convenience, and comfort of the inhabitants of the

(A) For process equipment having process weight rates of up to thirty (30) tons per hour, the allowable emission rate shall be determined by the use of the equation:

$$PE = 3.59(P)^{0.62}$$

Where:

PE = Particulate emission in lbs. per hour

P = Process weight rate in ton per hour

(B) For process equipment having process weight rates of greater than thirty (30) tons per hour, the allowable emission rate shall be determined by use of the equation:

$$PE = 17.31(P)^{0.16}$$

Where:

PE = Particulate emission rate in lbs. per hour

P = Process weight rate in tons per hour

(C) If two or more process units are connected to the same opening, the maximum allowable emission rate shall be computed by summing the individual emissions rates.

(ii) Performance Tests

Prior to granting or amending a permit, when an emission source or control equipment is altered, or at any time when there is reason to believe that emission standards are being violated, the Division may require the owner or operator of an existing manufacturing process to conduct performance test(s) as measured by EPA Methods (1-4) and the front half of EPA Method 5 (40 CFR 60.275, Appendix A, Part 60) as may be amended to determine compliance with this subsection of this regulation.

G. A statement of the basis and purpose for the revisions to this Section V., adopted March 11, 1982 is hereby incorporated by reference, and a copy of the statement is available from the Air Quality Control Commission office.

VI. SULFUR DIOXIDE EMISSION REGULATIONS

A. Sources constructed or modified prior to August 11, 1977 shall be considered an existing source. All existing sources of sulfur dioxide emissions, except for sources listed in Section VII, shall comply with the following:

1. Averaging time - Unless otherwise specified in other sections of this regulation, the averaging time for all sulfur dioxide emissions standards for sources which utilize a CEM shall be a three hour rolling average and the frequency of fuel sampling for sources which utilize a fuel sampling plan approved pursuant to Section IV.B.2. shall be as specified in such plan.

2. If the sum of sulfur dioxide emission rates for all sources located on a contiguous site is less than three (3) tons per day potential uncontrolled SO_2 emissions, and if all Federal and State Ambient Air Quality Standards are met no process based SO_2 emission standard shall apply.

3. Existing sources of sulfur dioxide shall not emit sulfur dioxide in excess of the following process-specific limitations. (Heat input rates shall be the manufacturer's guaranteed maximum heat input rates).

   a. Coal-fired operations including coal-fired steam generation:

      (These standards are also applicable to the use of coal-based by-product fuels.)

      (i) Units with a heat input from coal or coal-based by-product fuels of less than 300 million BTU per hour:

         1.8 pounds of sulfur dioxide per million BTU of heat input.

      (ii) Units with a heat input from coal or coal-based by-product fuels equal to or greater than 300 million BTU per hour:

         1.2 pounds of sulfur dioxide per million BTU of heat input.

   b. Oil-fired Operations Including Oil-Fired Steam Generation

      (i) Units with a heat input from oil of less than 300 million BTU per hour:

         1.5 pounds of sulfur dioxide per million BTU of heating input.

      (ii) Units with a heat input from oil equal to or greater than 300 million BTU per hour:

         0.8 pounds of sulfur dioxide per million BTU of heating input.

c. Combustion Turbines

(i) Combustion Turbines with a heat input of less than 300 million BTU per hour:

1.2 pounds of sulfur dioxide per million BTU of heating input.

(ii) Combustion Turbines with a heat input equal to or greater than 300 million BTU per hour:

0.8 pounds of sulfur dioxide per million BTU of heating input.

d. Natural Gas Desulfurization

Desulfurization Plants emitting more than five (5) tons of sulfur dioxide per day:

2 pounds of sulfur dioxide per 1,000 cubic feet of (Actual) delivered gas.

e. Petroleum Refining

0.7 pounds sulfur dioxide for the sum of all SO_2 emissions from a given Refinery, per barrel of oil processed, per day. This emission limit shall be calculated over each 24 hour period which commences at midnight. If the refinery does not operate for the entire 24 hour period, the actual hours of operation shall be used as the averaging time. At no time shall the averaging time be greater than 24 hours. Refineries in operation on or before August 1, 1995, which are covered by this regulation, shall submit a plan for Division approval no later than February 1, 1996. Sources constructed after August 1, 1995 shall submit a plan for Division approval along with construction permit applications. The plan shall define how compliance with this limitation will be demonstrated. This plan shall address both how the SO_2 value is calculated, i.e. mass balance, monitors, and how the barrels of oil processed value is derived, taking into account intermediate storage. The Division shall not limit the determination of barrels processed per day to a 24 hour period.

All data used to show compliance with this emission standard shall be maintained by the owner or operator of the affected source for a period of two (2) years for sources that are not subject to the operating permit program, and five (5) years for sources that are subject to the operating permit program. This data shall be available for inspection by the Division upon request.

f. Cement Manufacture

abrogate the Commission's or Division's authority to require testing under Article 7 of Title 25, Colorado Revised Statute 1973, and regulations of the Commission promulgated thereunder.

3. The owner or operator of an affected facility shall provide the Division thirty (30) days prior notice of the performance test to afford the Division the opportunity to have an observer present.

E. Related Compounds Containing Sulfur in Oxidized States:

1. For the purposes of this regulation, all oxidized forms of sulfur (including, but not restricted to sulfur trioxide (SO_3), trionyl chloride ($SOCl_2$), and sulfuric acid mist (H_2SO_4)) shall be considered as sulfur dioxide.

2. Quantities of such oxidized sulfur compounds shall be converted on a molar basis to an equivalent quantity of sulfur dioxide. The total of all such quantities, (expressed in parts per million by volume sulfur-dioxide-equivalents of other oxidized forms) shall be interpreted as "parts per million by volume sulfur dioxide" as used in Section B. above.

F. Alternative Compliance Procedures

1. Any person may apply to the Division Director for approval of an alternative:

a. Test method,

b. Method of control,

c. Compliance period,

d. Emission limit, or

e. Monitoring schedule.

2. The application shall include a demonstration that the proposed alternative produces:

a. An equal or greater air quality benefit than that required in this subsection VI, or

b. The alternative test method is equivalent to that required by these regulations.

3. The Division Director shall obtain concurrence from EPA prior to approving an alternative.

VII. EMISSION REGULATIONS FOR CERTAIN ELECTRIC GENERATING STATIONS OWNED AND OPERATED BY THE PUBLIC SERVICE COMPANY OF COLORADO

A. The electric generating stations owned and operated by the Public Service Company of Colorado listed below shall not emit or cause to be emitted nitrogen oxides (NO_x) or sulfur dioxide (SO_2) in excess of the following limits. The emission rates for NO_x and SO_2 are measure in terms of pounds of pollutant per million British Thermal Units of fuel fired in the unit (lb/mmBTU).

1. Cherokee Electric Generating Station, 6198 North Franklin Street, Denver, CO

	NO_X (lb/mmBTU)	SO_2 (lb/mmBTU)
Unit 1	-	1.1
Unit 2	-	1.1
Unit 3	0.60	1.1
Unit 4	0.45	1.1

- The NO_X limit will be calculated based on a 30-day rolling average, and is effective November 1, 1994.
- The SO_2 limit will be calculated as a three-hour rolling average, and is effective November 1, 1994.
- Public Service Company of Colorado shall install, certify and operate continuous emission monitoring equipment for measuring opacity, SO_2, NO_X, and either O_2 or CO_2 on Units 1, 2, 3 and 4 no later than January 1, 1995.

2. Arapahoe Electric Generating Station, 2601 South Platte River Drive, Denver, CO

	NO_X (lb/mmBTU)	SO_2 (lb/mmBTU)
Unit 1	-	1.1
Unit 2	-	1.1
Unit 3	-	1.1
Unit 4	.60	1.1 +20% annual tonnage reduction

- The NO_X limit will be calculated based on a 30-day rolling average, and is effective November 1, 1994.
- The SO_2 limit will be calculated as a three-hour rolling average, and is effective January 1, 1995.

- The 20% SO_2 limit from Unit 4 shall be calculated on a calendar year, total annual tonnage basis. SO_2 removal Equipment shall be continuously operated from November 1 to March 1 of each year, except during periods of upset conditions or because of unavoidable circumstances that render the equipment inoperable. If at any time between November 1 and March 1 of any year the equipment is not operated for a period of 24 hours or longer, Public Service Company of Colorado shall report the event to the Division in accordance with the Common Provisions Regulation.
- Public Service Company of Colorado shall install, certify and operate continuous emission monitoring equipment for measuring opacity, SO_2, NO_X, and either O_2 or CO_2 on Units 1, 2, 3 and 4 no later than January 1, 1995.

3. Valmont Electric Generating Station, 1800 North 63rd Street, Boulder, CO

	NO_X (lb/mmBTU)	SO_2 (lb/mmBTU)
Unit 5	0.45	1.1

- The NO_X limit will be calculated based on a 30-day rolling average, and is effective November 1, 1994.
- The SO_2 limit will be calculated as a three-hour rolling average, and is effective November 1, 1994.
- Public Service Company of Colorado shall install, certify and operate continuous emission monitoring equipment for measuring opacity, SO_2, NO_X, and either O_2 or CO_2 on Units 1, 2, 3 and 4 no later than January 1, 1995.

B. Public Service Company of Colorado shall submit to the Division for approval, no later than June 30, 1994, the procedure to be used for the measurement and calculation of the emission averages and emission reductions from these electric generating stations.

VIII. RESTRICTIONS ON THE USE OF OIL AS A BACKUP FUEL

A. Applicability

The provisions of this section are applicable to all points at the following stationary sources in the Denver PM10 nonattainment area that use oil as a backup fuel for natural gas, which is the primary process fuel:

1. Public Service Company of Colorado, Zuni Electric Generating Station;
2. Public Service Company of Colorado, Valmont Electric Generating Station;
3. Public Service Company of Colorado, Delgany Steam Generating Station;
4. Fitzsimmons Army Medical Center;

5. US Department of Energy, Rocky Flats Plant;

6. Gates Rubber Company; and

7. Coors Brewing Company, Coors Brewery, Golden, CO.

B. Requirements

Beginning November 1, 1993, natural gas shall be the only fuel used from November 1 to March 1 of each year, except under the following circumstances:

1. the supplier of transporter or natural gas imposes a curtailment or an interruption of service;

2. for necessary testing of equipment used to operate the unit on oil, testing of fuel and training of personnel; or

3. when an equipment malfunction at the facility makes it impossible or unsafe for the unit to operate on natural gas.

C. Recordkeeping

Each stationary source subject to the provisions shall maintain records for a period of two years which include the following information:

1. dates and number of hours fuel oil is burned;

2. percent sulfur analysis of the fuel oil that is burned;

3. number of gallons burned each day; and

4. reason(s) for the use of the fuel oil.

D. Reporting

Beginning April 1, 1994 and by April 1 of each year thereafter, each stationary source subject to these provisions shall submit to the division a report containing the information listed in Section VIII.C.

E. Alternate Recordkeeping and Reporting

Where the information required under subsections C and D above is otherwise made available to the Division, for example in EIS reports submitted by the source or pursuant to operating permit requirements, the requirements of subsections C and D of this Section VIII are satisfied.

IX. EMISSION REGULATIONS CONCERNING AREAS WHICH ARE NONATTAINMENT FOR CARBON MONOXIDE - REFINERY FLUID BED CATALYTIC CRACKING UNITS:

Appendix E.2 T5 Emission Factors

2002 Maximum Allowable Emissions
Major NOx, SO2 & PM10 Sources

Source	Maximum Operation		SO2						NOx				PM10				
Cherokee	Design Rate mmBtu/hr	hr/yr	ton/lb	Emission Limit lb/mmBtu	Control Efficiency (%)	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tons/day)	Emission Limit lb/mmBtu	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tons/day)	Reg. 1 Emission Limit lb/mmBtu	Fraction PM10 of PM	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tons/day)
Unit 1	1392	8760	0.0005	1.1	20	5,365	1,225	14.7	0.96	5,853	1336	16.0	0.1	0.92	561	128	1.5
Unit 2	1392	8760	0.0005	1.1	0	6,707	1,531	18.4	0.96	5,853	1336	16.0	0.1	0.92	561	128	1.5
Unit 3	1877	8760	0.0005	1.1	0	9,043	2,065	24.8	0.60	4,933	1126	13.5	0.1	0.92	756	173	2.1
Unit 4	3520	8760	0.0005	1.1	20	13,567	3,098	37.2	0.45	6,938	1584	19.0	0.1	0.92	1,418	324	3.9
TOTAL						**34,683**	**7,918**	**95.0**		**23,577**	**5,383**	**64.6**			**3,297**	**753**	**9.0**
Arapahoe																	
Unit 1	754.8	8760	0.0005	1.1	0	3,637	830	10.0	0.98	3,240	740	8.9	0.1	0.67	222	51	0.6
Unit 2	754.8	8760	0.0005	1.1	0	3,637	830	10.0	0.98	3,240	740	8.9	0.1	0.67	222	51	0.6
Unit 3	754.8	8760	0.0005	1.1	0	3,637	830	10.0	0.98	3,240	740	8.9	0.1	0.92	304	69	0.8
Unit 4	1709.0	8760	0.0005	1.1	20	6,587	1,504	18.0	0.6	4,491	1025	12.3	0.1	0.92	689	157	1.9
2 Turbines (2002)		8760	0.0005			0.5*	0.4	0.0		39*	62	0.7			8*	6	0.1
TOTAL						**17,498**	**3,995**	**47.9**		**14,250**	**3,307**	**39.7**			**1,444**	**334**	**4**
Valmont																	
Unit 5	1845	8760	0.0005	1.1	0	8,889	2,030	24.4	0.45	3,636	830	10.0					
Unit 6	570	8760	0.0005	0.0006		1	0	0.0	0.32	799	182	2.2					
2 Turbine (2002)		8760	0.0005			0.5*	0.4	0.0		39*	61	0.7					
TOTAL						**8,891**	**2,030**	**24.4**		**4,474**	**1,074**	**12.9**					
Trigen																	
Boiler 1 (gas)	288	8760	0.0005	0.0006		1	0	0.0	0.28	353	81	1.0	0.11		139	32	0.4
Boiler 2 (gas)	288	8760	0.0005	0.0006		1	0	0.0	0.28	353	81	1.0	0.11		139	32	0.4
Boiler 3	225	8760	0.0005	1.8		1,774	405	4.9	0.4	384	88	1.1	0.12	1	118	27	0.3
Boiler 4	360	8760	0.0005	1.2		1,892	432	5.2	0.7	1,104	252	3.0	0.10	1	158	36	0.4
Boiler 5	650	8760	0.0005	1.2		3,416	780	9.4	0.7	1,993	455	5.5	0.10	1	285	65	0.8
SIP reduction			0.0005			-125	-29	-0.3		-225	-51	-0.6					
TOTAL						**6,959**	**1,589**	**19.1**		**3,962**	**905**	**10.9**			**838**	**191**	**2.3**
Rocky Mtn. Bottle																	
PTE by stack test						369	84	1.0		424	97	1.2					
TOTAL						**369**	**84**	**1.0**		**424**	**97**	**1.2**					
Conoco Refinery	Barrels/day												lb/barrel	Em. Factor			
FCCU**	20,000	8760	0.0005										0.051		185.4	42	0.5
See attachment		8760	0.0005												41	9	0.1
TOTAL															**226**	**52**	**0.6**
UDS Refinery	lb Coke/hr												lb/lb Coke	Em. Factor			
FCCU***	5,789	8760	0.0005										0.00788		200	46	0.5
See attachment		8760	0.0005												42	9	0.1
TOTAL															**241**	**55**	**0.7**
Robinson Brick	Design Rate												lbs PM/hr				
Rotary Dryer	35/Tons/Hr.	8760	0.0005										30.57	0.24	32	7	0.1
Tunnel Dryer (2)	Reg. 1 Limit	8760	0.0005										17.9	1	130.8*	18	0.2
Rotary Calciner	10 Tons/Hr	8760	0.0005										14.97	0.34	22	5	0.1
TOTAL															**186**	**30**	**0.4**

* Annual Permit Limits; pte emissions modeled at maximum hourly emissions rate

** FCCU feed Rate-Barrels per day-Emisions Rate lbs.PM10/1000 barrels and total pte emissions calculation by source

*** Total pte emissions calculation by Source

NOTE: This revision includes pte calculations for Cherokee 1-2, Arapahoe 1-3, Trigen 3 and RMB for NOx and RMB for SO2. Also, addition of Valmont 6.

2003 Maximum Allowable Emissions

Major NOx, SO2 & PM10 Sources

Source	Maximum Operation		SO2						NOx				PM10				
Cherokee	Design Rate mmBtu/hr	hr/yr	ton/lb	Emission Limit lb/mmBtu	Control Efficiency (%)	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tons/day)	Emission Limit lb/mmBtu	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tons/day)	Reg. 1 Emission Limit lb/mmBtu	Fraction PM10 of PM	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tons/day)
Unit 1	1392	8760	0.0005	1.1	20	5,365	1,225	14.7	0.96	5,853	1336	16.0	0.1	0.92	561	128	1.5
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TOTAL						**34,683**	**7,918**	**95.0**		**23,577**	**5,383**	**64.6**			**3,297**	**753**	**9.0**
Arapahoe																	
Unit 1 (ret. by 1/1/03)	754.8			1.1	0				0.98				0.1	0.67			
Unit 2 (ret. by 1/1/03)	754.8			1.1	0				0.98				0.1	0.67			
Unit 3	754.8	8760	0.0005	1.1	0	3,637	830	10.0	0.98	3,240	740	8.9	0.1	0.92	304	69	0.8
Unit 4	1709.0	8760	0.0005	1.1	20	6,587	1,504	18.0	0.6	4,491	1025	12.3	0.1	0.92	689	157	1.9
2 Turbines (2002)		8760	0.0005			0.5*	0.4	0.0		39*	62	0.7			8*	6	0.1
TOTAL						**10,224**	**2,335**	**28.0**		**7,770**	**1,827**	**21.9**			**1,001**	**233**	**2.8**
Valmont																	
Unit 5	1845	8760	0.0005	1.1	0	8,889	2,030	24.4	0.45	3,636	830	10.0					
Unit 6	570	8760	0.0005	0.0006		1	0	0.0	0.32	799	182	2.2					
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TOTAL						**8,891**	**2,030**	**24.4**		**4,474**	**1,074**	**12.89**					
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Boiler 4	360	8760	0.0005	1.2		1,892	432	5.2	0.7	1,104	252	3.0	0.10	1	158	36	0.4
Boiler 5	650	8760	0.0005	1.2		3,416	780	9.4	0.7	1,993	455	5.5	0.1	1	285	65	0.8
SIP reduction			0.0005			-125	-29	-0.3		-225	-51	-0.6					
TOTAL						**6,959**	**1,589**	**19.1**		**3,962**	**905**	**10.9**			**838**	**191**	**2.3**
Rocky Mtn. Bottle																	
PTE by stack test						369	84	1.0		424	97	1.2					
TOTAL						**369**	**84**	**1.0**		**424**	**97**	**1.2**					
Conoco Refinery	Barrels/day												lb/barrel	Em. Factor			
FCCU**	20,000	8760	0.0005										0.051		185.4	42	0.5
See attachment		8760	0.0005												41	9	0.1
TOTAL															**226**	**52**	**0.6**
UDS Refinery	lb Coke/hr												lb/lb Coke	Em. Factor			
FCCU***	5,789	8760	0.0005										0.00788		200	46	0.5
See attachment		8760	0.0005												42	9	0.1
TOTAL															**241**	**55**	**0.7**
Robinson Brick	Design Rate												lbs PM/hr				
Rotary Dryer	35/Tons/Hr.	8760	0.0005										30.57	0.24	32	7	0.1
Tunnel Dryer (2)	Reg. 1 Limit	8760	0.0005										17.9	1	131*	18	0.2
Rotary Calciner	10 Tons/Hr	8760	0.0005										14.97	0.34	22	5	0.1
TOTAL															**186**	**30**	**0.4**

* Annual Permit Limits; pte emissions modeled at maximum hourly emissions rate

** FCCU feed Rate-Barrels per day-Emisions Rate lbs.PM10/1000 barrels and total pte emissions calculation by source

*** Total pte emissions calculation by Source

NOTE: This revision includes pte calculations for Cherokee 1-2, Arapahoe 1-3, Trigen 3 and RMB for NOx and RMB for SO2. Also, addition of Valmont 6.

2005 Maximum Allowable Emissions

Major NOx, SO2 & PM10 Sources

Source	Maximum Operation		SO2						NOx				PM10				
Cherokee	Design Rate mmBtu/hr	hr/yr	ton/lb	Emission Limit lb/mmBtu	Control Efficiency (%)	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tons/day)	Emission Limit lb/mmBtu	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tons/day)	Reg. 1 Emission Limit lb/mmBtu	Fraction PM10 of PM	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tons/day)
Unit 1	1392	8760	0.0005	1.1	20	5,365	1,225	14.7	0.60	3,658	835	10.0	0.1	0.92	561	128	1.5
Unit 2	1392	8760	0.0005	1.1	0	6,707	1,531	18.4	0.96	5,853	1336	16.0	0.1	0.92	561	128	1.5
Unit 3	1877	8760	0.0005	1.1	0	9,043	2,065	24.8	0.60	4,933	1126	13.5	0.1	0.92	756	173	2.1
Unit 4	3520	8760	0.0005	1.1	20	13,567	3,098	37.2	0.45	6,938	1584	19.0	0.1	0.92	1,418	324	3.9
TOTAL						**34,683**	**7,918**	**95.0**		**21,382**	**4,882**	**58.6**			**3,297**	**753**	**9.0**
Arapahoe																	
Unit 1 (ret. by 1/1/03)	754.8			1.1	0				0.98				0.1	0.67			
Unit 2 (ret. by 1/1/03)	754.8			1.1	0				0.98				0.1	0.67			
Unit 3	754.8	8760	0.0005	1.1	0	3,637	830	10.0	0.98	3,240	740	8.9	0.1	0.92	304	69	0.8
Unit 4	1709.0	8760	0.0005	1.1	20	6,587	1,504	18.0	0.6	4,491	1025	12.3	0.1	0.92	689	157	1.9
2 Turbines (2002)		8760	0.0005			0.5*	0.4	0.0		39*	62	0.7			8*	6	0.1
TOTAL						**10,224**	**2,335**	**28.0**		**7,770**	**1,827**	**21.9**			**1,001**	**233**	**2.8**
Valmont																	
Unit 5	1845	8760	0.0005	1.1	0	8,889	2,030	24.4	0.45	3,636	830	10.0					
Unit 6	570	8760	0.0005	0.0006		1	0	0.0	0.32	799	182	2.2					
2 Turbine (2002)		8760	0.0005			0.5*	0.4	0.0		39*	61	0.7					
TOTAL						**8,891**	**2,030**	**24.4**		**4,474**	**1,074**	**12.89**					
Trigen																	
Boiler 1 (gas)	288	8760	0.0005	0.0006		1	0	0.0	0.28	353	81	1.0	0.11		139	32	0.4
Boiler 2 (gas)	288	8760	0.0005	0.0006		1	0	0.0	0.28	353	81	1.0	0.11		139	32	0.4
Boiler 3	225	8760	0.0005	1.8		1,774	405	4.9	0.4	384	88	1.1	0.12	1	118	27	0.3
Boiler 4	360	8760	0.0005	1.2		1,892	432	5.2	0.7	1,104	252	3.0	0.10	1	158	36	0.4
Boiler 5	650	8760	0.0005	1.2		3,416	780	9.4	0.7	1,993	455	5.5	0.1	1	285	65	0.8
SIP reduction			0.0005			-125	-29	-0.3		-225	-51	-0.6					
TOTAL						**6,959**	**1,589**	**19.1**		**3,962**	**905**	**10.9**			**838**	**191**	**2.3**
Rocky Mtn. Bottle																	
PTE by stack test						369	84	1.0		424	97	1.2					
TOTAL						**369**	**84**	**1.0**		**424**	**97**	**1.2**					
Conoco Refinery	Barrels/day												lb/barrel	Em. Factor			
FCCU**	20,000	8760	0.0005										0.051		185.4	42	0.5
See attachment		8760	0.0005												41	9	0.1
TOTAL															**226**	**52**	**0.6**
UDS Refinery	lb Coke/hr												lb/lb Coke	Em. Factor			
FCCU***	5,789	8760	0.0005										0.00788		200	46	0.5
See attachment		8760	0.0005												42	9	0.1
TOTAL															**241**	**55**	**0.7**
Robinson Brick	Design Rate												lbs PM/hr				
Rotary Dryer	35/Tons/Hr.	8760	0.0005										30.57	0.24	32	7	0.1
Tunnel Dryer (2)	Reg. 1 Limit	8760	0.0005										17.9	1	131*	18	0.2
Rotary Calciner	10 Tons/Hr	8760	0.0005										14.97	0.34	22	5	0.1
TOTAL															**186**	**30**	**0.4**

* Annual Permit Limits; pte emissions modeled at maximum hourly emissions rate

** FCCU feed Rate-Barrels per day-Emisions Rate lbs.PM10/1000 barrels and total pte emissions calculation by source

*** Total pte emissions calculation by Source

NOTE: This revision includes pte calculations for Cherokee 2, Arapahoe 1-3, Trigen 3 and RMB for NOx and RMB for SO2. Also, addition of Valmont 6 and 0.6 lb Nox/mmBtu at Cherokee 1

MAXIMUM ALLOWABLE EMISSIONS

Public Service Company - Zuni Station

Source	Design Rate (mmBtu/hr)	Reg. 1 Limit (lb/mmBtu)	Fraction PM10 of PM	Hours of Operation	ton/lb	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tpd)
Unit 1A (coal)	450	0.102	0.71	8760	0.0005	143	32.59	0.39
Unit 1B (coal)	200	0.126	0.71	8760	0.0005	78	17.89	0.21
Unit 2 (coal)	1075	0.1	0.71	8760	0.0005	334	76.33	0.92
Total						555	127	2

APCD staff included Zuni in the ISC modeling for major sources of PM10 and used the Regulation 1 emissions limit for combustion sources, which is fuel neutral. Regulation 1, however, includes a provision that requires Zuni to be operated on gas during the winter season; and a more appropriate calculation is included below. The ISC modeling indicates that at the the emission rate calculated using the Regulation 1 limit above (555 tpy) has a negligible effect on receptor concentration. Additional ISC modeling with the more appropriate 56 tpy was considered unnecessary.

Source	Design Rate (mmBtu/hr)	Heat Value (scf/1000 Btu)	lbs. PM10/ mmscf	Hours of Operation	ton/lb	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tpd)
Unit 1A (gas)	450	0.001	7.45	8760	0.0005	15	3.35	0.04
Unit 1B (gas)	200	0.001	7.45	8760	0.0005	7	1.49	0.02
Unit 2 (gas)	1075	0.001	7.45	8760	0.0005	35	8.01	0.10
Total						56	13	0

Source	Design Rate (mmBtu/hr)	Heat Value (scf/1000 Btu)	lbs. NOx/ mmscf*	Hours of Operation	ton/lb	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tpd)
Unit 1A (gas)	450	0.001	280	8760	0.0005	552	126.00	1.51
Unit 1B (gas)	200	0.001	280	8760	0.0005	245	56.00	0.67
Unit 2 (gas)	1075	0.001	280	8760	0.0005	1318	301.00	3.61
Total						2116	483	5.80

* new AP-42 emission factor

Source	Design Rate (mmBtu/hr)	Heat Value (scf/1000 Btu)	lbs. SO2/ mmscf	Hours of Operation	ton/lb	Emission Rate (tpy)	Emission Rate (lb/hr)	Emission Rate (tpd)
Unit 1A (gas)	450	0.001	0.6	8760	0.0005	1	0.27	0.00
Unit 1B (gas)	200	0.001	0.6	8760	0.0005	1	0.12	0.00
Unit 2 (gas)	1075	0.001	0.6	8760	0.0005	3	0.65	0.01
Total						5	1	0

Prepared by Jerry Dilley

Appendix E.3 AP – 42 Emission Factors

Table 1.1-6. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR DRY BOTTOM BOILERS BURNING PULVERIZED BITUMINOUS AND SUBBITUMINOUS COAL[a]

Particle Size[b] (μm)	Cumulative Mass % ≤ Stated Size					Cumulative Emission Factor[c] (lb/ton)				
		Controlled					Controlled[e]			
	Uncontrolled	Multiple Cyclones	Scrubber	ESP	Baghouse	Uncontrolled[d]	Multiple Cyclones[f]	Scrubber[g]	ESP[g]	Baghouse[f]
15	32	54	81	79	97	3.2A	1.08A	0.48A	0.064A	0.02A
10	23	29	71	67	92	2.3A	0.58A	0.42A	0.054A	0.02A
6	17	14	62	50	77	1.7A	0.28A	0.38A	0.024A	0.02A
2.5	6	3	51	29	53	0.6A	0.06A	0.3A	0.024A	0.01A
1.25	2	1	35	17	31	0.2A	0.02A	0.22A	0.01A	0.006A
1.00	2	1	31	14	25	0.2A	0.02A	0.18A	0.01A	0.006A
0.625	1	1	20	12	14	0.10A	0.02A	0.12A	0.01A	0.002A
TOTAL	100	100	100	100	100	10A	2A	0.6A	0.08A	0.02A

[a] Reference 33. Applicable Source Classification Codes are 1-01-002-02, 1-02-002-02, 1-03-002-06, 1-01-002-12, 1-02-002-12, and 1-03-002-16. To convert from lb/ton to kg/Mg, multiply by 0.5. Emission Factors are lb of pollutant per ton of coal combusted, as fired. ESP = Electrostatic precipitator.
[b] Expressed as aerodynamic equivalent diameter.
[c] A = coal ash weight percent, as fired. For example, if coal ash weight is 8.2%, then A = 8.2.
[d] EMISSION FACTOR RATING = C.
[e] Estimated control efficiency for multiple cyclones is 80%; for scrubber, 94%; for ESP, 99.2%; and for baghouse, 99.8%.
[f] EMISSION FACTOR RATING = E.
[g] EMISSION FACTOR RATING = D.

Table 1.3-4. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC EMISSION FACTORS FOR UTILITY BOILERS FIRING RESIDUAL OIL[a]

Particle Size[b] (μm)	Cumulative Mass % ≤ Stated Size			Cumulative Emission Factor lb/10^3 gal)					
		Controlled		Uncontrolled[c]		ESP Controlled[d]		Scrubber Controlled[e]	
	Uncon-trolled	ESP	Scrubber	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING	Emission Factor	EMISSION FACTOR RATING
15	80	75	100	6.7A	C	0.05A	E	0.50A	D
10	71	63	100	5.9A	C	0.042A	E	0.50A	D
6	58	52	100	4.8A	C	0.035A	E	0.50A	D
2.5	52	41	97	4.3A	C	0.028A	E	0.48A	D
1.25	43	31	91	3.6A	C	0.021A	E	0.46A	D
1.00	39	28	84	3.3A	C	0.018A	E	0.42A	D
0.625	20	20	64	1.7A	C	0.007A	E	0.32A	D
TOTAL	100	100	100	8.3A	C	0.067A	E	0.50A	D

[a] Reference 26. Source Classification Codes 1-01-004-01/04/05/06 and 1-01-005-04/05. To convert from lb/10^3 gal to kg/m^3, multiply by 0.120. ESP = electrostatic precipitator.

[b] Expressed as aerodynamic equivalent diameter.

[c] Particulate emission factors for residual oil combustion without emission controls are, on average, a function of fuel oil grade and sulfur content where S is the weight % of sulfur in the oil. For example, if the fuel is 1.00% sulfur, then S = 1.

No. 6 oil: A = 1.12(S) + 0.37

No. 5 oil: A = 1.2

No. 4 oil: A = 0.84

[d] Estimated control efficiency for ESP is 99.2%.

[e] Estimated control efficiency for scrubber is 94%

Table 11.25-8. PARTICLE SIZE DISTRIBUTIONS FOR FIRE CLAY PROCESSING[a]

EMISSION FACTOR RATING: D

Diameter (μm)	Uncontrolled	Multiclone Controlled	Cyclone Controlled	Cyclone/Scrubber Controlled
	Cumulative % Less Than Diameter	Cumulative % Less Than Diameter	Cumulative % Less Than Diameter	Cumulative % Less Than Diameter
Rotary Dryers (SCC 3-05-043-30)[b]				
2.5	2.5	ND	14	ND
6.0	10	ND	31	ND
10.0	24	ND	46	ND
15.0	37	ND	60	ND
20.0	51	ND	68	ND
Rotary Calciners (SCC 3-05-43-40)[c]				
1.0	3.1	13	ND	31
1.25	4.1	14	ND	43
2.5	6.9	23	ND	46
6.0	17	39	ND	55
10.0	34	50	ND	69
15.0	50	63	ND	81
20.0	62	81	ND	91

[a] For filterable PM only. SCC = Source Classification Code. ND = no data.
[b] Reference 11.
[c] References 12-13 (uncontrolled). Reference 12 (multiclone-controlled). Reference 13 (cyclone/scrubber-controlled).

Table 1.1-3. UNCONTROLLED EMISSION FACTORS FOR SO_x, NO_x, AND CO FROM BITUMINOUS AND SUBBITUMINOUS COAL COMBUSTION[a]

Firing Configuration	SCC	SO_x[b] Emission Factor (lb/ton)	SO_x[b] EMISSION FACTOR RATING	NO_x[c] Emission Factor (lb/ton)	NO_x[c] EMISSION FACTOR RATING	CO[d,e] Emission Factor (lb/ton)	CO[d,e] EMISSION FACTOR RATING
PC-fired, dry bottom, wall-fired	1-01-002-02/22 1-02-002-02/22 1-03-002-06/22	38S (35S)	A	21.7	A	0.5	A
PC-fired, bituminous coal, dry bottom, cell burner fired[f]	1-01-002-15	38S (35S)	A	31.1	C	0.5	A
PC-fired, dry bottom, tangentially fired	1-01-002-12/26 1-02-002-12/26 1-03-002-16/26	38S (35S)	A	14.4	A	0.5	A
PC-fired, wet bottom	1-01-002-01/21 1-02-002-01/21 1-03-002-05/21	38S (35S)	D	34.0	C	0.5	A
Cyclone furnace	1-01-002-03/23 1-02-002-03/23 1-03-002-03/23	38S (35S)	D	33.8	C	0.5	A
Spreader stoker	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	38S (35S)	B	13.7	A	5	A
Spreader stoker, with multiple cyclones, and reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	38S (35S)	B	13.7	A	5	A
Spreader stoker, with multiple cyclones, no reinjection	1-01-002-04/24 1-02-002-04/24 1-03-002-09/24	38S (35S)	A	13.7	A	5	A

Table 1.1-3 (cont.).

Firing Configuration	SCC	SO_x[b]		NO_x[c]		CO[d,e]	
		Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING	Emission Factor (lb/ton)	EMISSION FACTOR RATING
Cyclone Furnace, bituminous	1-01-002-03 1-02-002-03 1-03-002-03	38S	A	33	A	0.5	A
Cyclone Furnance, sub-bituminous	1-01-002-23 1-02-002-23 1-03-002-23	35S	A	17	C	0.5	A
Spreader stoker, bituminous	1-01-002-04 1-02-002-04 1-03-002-09	38S	B	11	B	5	A
Spreader Stoker, sub-bituminous	1-01-002-24 1-02-002-24 1-03-002-24	35S	B	8.8	B	5	A
Overfeed stoker[j]	1-01-002-05/25 1-02-002-05/25 1-03-002-07/25	38S (35S)	B	7.5	A	6	B
Underfeed stoker	1-02-002-06 1-03-002-08	31S	B	9.5	A	11	B
Hand-fed units	1-03-002-14	31S	D	9.1	E	275	E

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_X) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors[a]				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines[b]	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02[d]	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines[e]	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines[g]	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines[j]	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

[a] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[b] Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020.

[d] It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

[e] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[f] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[g] SCC for landfill gas-fired turbines is 2-03-008-01.

[h] Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu); to (lb/10^6 scf) multiply by 400.

[j] SCC for digester gas-fired turbine is 2-03-007-01.

[k] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf) multiply by 600.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor (lb/10^6 scf)	Emission Factor Rating	Emission Factor (lb/10^6 scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 13. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from lb/10^6 scf to kg/10^6 m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from 1b/10^6 scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_x emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_x emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 13. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6 \text{ scf}] = (3.67)$ (CON) (C)(D), where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, 4.2×10^4 $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

Appendix E.4 Emission Inventory Supporting Information

Conoco Refinery

Post-it® Fax Note 7671	Date 1-22-01 # of pages ▶ 1
To Long Nguyen	From Jay Christopher
Co./Dept. [redacted] APCD	Co. Conoco
Phone # 303-692-3106	Phone # 303-286-5731
Fax # 303-782-0278	Fax # 303-286-5866

Conoco Denver Refinery
PM Data/Calculations Used For TitleV PTE

APEN #	Source ID	PM-10 PTE provide in table to APCD	TV Fuel Use (mmscf/yr)	TV Factor (lb/mmscf)	Calc. PTE (lbs/year)	Calc. PTE (TPY)	Emission Factor Source
2	H-31	1.41	206.39	13.7	2827.543	1.41	AP-42, Section 1.4 (1/95 update)
3	H-32	2.27	331.13	13.7	4536.481	2.27	AP-42, Section 1.4 (1/95 update)
4	H-6	0.86	126.14	13.7	1728.118	0.86	AP-42, Section 1.4 (1/95 update)
6	H-8	1.00	145.42	13.7	1992.254	1.00	AP-42, Section 1.4 (1/95 update)
7	H-10	2.04	298.02	13.7	4082.874	2.04	AP-42, Section 1.4 (1/95 update)
9	H-11	1.79	260.7	13.7	3571.59	1.79	AP-42, Section 1.4 (1/95 update)
10	H-33	0.40	67.28	12	807.36	0.40	AP-42, Section 1.4 (1/95 update)
11	H-12	1.77	258.77	13.7	3545.149	1.77	AP-42, Section 1.4 (1/95 update)
12	H-37	3.43	501.42	13.7	6869.454	3.43	AP-42, Section 1.4 (1/95 update)
13	H-17	3.50	511.58	13.7	7008.646	3.50	AP-42, Section 1.4 (1/95 update)
14	H-13	0.36	59.57	12	714.84	0.36	AP-42, Section 1.4 (1/95 update)
16	H-19	1.75	255.62	13.7	3501.994	1.75	AP-42, Section 1.4 (1/95 update)
17	H-20	0.84	122.64	13.7	1680.168	0.84	AP-42, Section 1.4 (1/95 update)
18	H-22	3.59	523.5	13.7	7171.95	3.59	AP-42, Section 1.4 (1/95 update)
19	B-4	1.71	1138.8	3	3416.4	1.71	AP-42, Section 1.4 (1/95 update)
21	B-6	1.46	972.36	3	2917.08	1.46	AP-42, Section 1.4 (1/95 update)
23	B-8	2.12	1410.36	3	4231.08	2.12	AP-42, Section 1.4 (1/95 update)
51	H-18	0.32	52.56	12	630.72	0.32	AP-42, Section 1.4 (1/95 update)
52	H-16	0.32	52.56	12	630.72	0.32	AP-42, Section 1.4 (1/95 update)
53	#1 SRU	0.01			0	0.00	
54	H-27	4.59	669.96	13.7	9178.452	4.59	AP-42, Section 1.4 (1/95 update)
78	H-28,29,30	5.32	776.14	13.7	10633.12	5.32	AP-42, Section 1.4 (1/95 update)

APEN #	Source ID	PM-10 PTE	TV Feed Rate (mBbl/yr)	TV Factor (lb/mBbl)	Calc. PTE (lbs/year)	Calc. PTE (TPY)	Emission Factor Source
25	FCC	194.69	7300	50.8	370840	185.42	PM emissions from the unit are controlled by a 2-stage cyclone. The emission factor is determined by applying an 85% control efficiency (see AP-42, Section 5.1, page 5.1-9) to the uncontrolled factors of 340 lbs/mBbl fresh feed.

Recall earlier discussion about using lower Feed Rate
185.42 is my number to use.

From: "Congram, Anthony R." <Anthony.R.Congram@usa.conoco.com>
To: 'MIKE Silverstein' <mcsilver@smtpgate.dphe.state.co.us>
Date: 3/26/01 2:15PM
Subject: RE: FCC Control Efficiency Question

FCC cyclones are completely integral. No means to bypass.

Tony Congram
Voice: 303-286-5890
Fax: 5866
anthony.r.congram@usa.conoco.com <mailto:anthony.r.congram@usa.conoco.com>

-----Original Message-----
From: MIKE Silverstein [SMTP:mcsilver@smtpgate.dphe.state.co.us]
Sent: Monday, March 26, 2001 2:05 PM
To: Anthony.R.Congram@usa.conoco.com
Subject: Re: FCC Control Efficiency Question

Next question: Are the cyclones inherent to the system - can they
be
by-passed/shut down and the FCCU still operated?

>>> "Congram, Anthony R." <Anthony.R.Congram@usa.conoco.com>
03/26/01
11:03AM >>>
Mike, is this enough of a reference (from AP-42, Chapter 5)?

Third paragraph under 5.1.2.2.2, page 8 or 9 of the document
(depending
on
formatting).

"FCC particulate emissions are controlled by cyclones and/or
electrostatic
precipitators.
Particulate control efficiencies are as high as 80 to 85 percent.3,5
Carbon
monoxide waste heat boilers
reduce the CO and hydrocarbon emissions from FCC units to negligible
levels.3 TCC catalyst
regeneration produces similar pollutants to FCC units, but in much
smaller
quantities (Table 5.1-1).
The particulate emissions from a TCC unit are normally controlled by

high-efficiency cyclones.
Carbon monoxide and hydrocarbon emissions from a TCC unit are
incinerated to
negligible levels by
passing the flue gases through a process heater firebox or smoke
plume
burner. In some installations,
sulfur oxides are removed by passing the regenerator flue gases
through
a
water or caustic
scrubber.2-3,5"

If that's not what you need, please call me back. Thanks.

Tony Congram
Voice: 303-286-5890
Fax: 5866
anthony.r.congram@usa.conoco.com
<mailto:anthony.r.congram@usa.conoco.com>

CC: "Christopher, Jay S." <Jay.S.Christopher@usa.conoco.com>, "Walker, Constance M. (Tance)" <Constance.M.Walker@usa.conoco.com>

From: "Christopher, Jay S." <Jay.S.Christopher@usa.conoco.com>
To: 'MIKE Silverstein' <mcsilver@smtpgate.dphe.state.co.us>
Date: 3/27/01 3:26PM
Subject: RE: FCC Control Efficiency Question

Mike - sorry I have been difficult to get a hold of recently (traveling), and glad Tony Congram was able to provide some information for you. I thought it might be useful to package things together in one note, plus add some more detail. I am also copying Jerry Dilley since he has been involved in this discussion in the past.

Are the cyclones in the FCCU an inherent part of the process? Yes, they are. The cyclones are not a control device in the sense of an add-on control device, but are a standard part of the design and operation of the unit. In fact, if one looked at a petroleum refining text, cyclones would be included in the basic diagrams of a FCCU. The cyclones cannot be bypassed and the FCCU could not operate without the cyclones in place and functioning. Also, no one would have an incentive to operate without cyclones, as that would increase losses of expensive catalyst to the atmosphere, and I do not believe that a FCCU could achieve any reasonable opacity limit without the cyclones operating appropriately.

More background on the FCCU emission factor used by Conoco - As you know, the AP-42 emission factor (Table 5.1-1) is 242 pounds particulate per 1000 barrels of fresh feed to the unit. AP-42 also includes a range of 93 - 340 pounds. Conoco uses the upper end factor (i.e., the most conservative value) of 340, and then applies a control efficiency factor to that rate.
As mentioned in the AP-42 text forwarded to you on 3/26/01(paragraph following Section 5.1.2.2.2), AP-42 states "FCC particulate emissions are controlled by cyclones and/or electrostatic precipitators. Particulate control efficiencies are as high as 80 - 85%." Conoco has relied on that combination of factor and efficiency to estimate the particulate emissions from our FCCU.

A recent EPA publication reinforces Conoco's view that this control efficiency factor is reasonable. EPA's CHIEF website includes a program called the "Enhanced Particulate Matter Controlled Emissions Calculator," dated September 2000. This program is designed to determine control efficiencies for different particulate matter fractions. EPA lists three levels of cyclone efficiencies (high, medium, and low) in this database. Since coarser particulate fractions are controlled more effectively, the percentages shown for PM10 are conservative. EPA states that a medium efficiency cyclone is considered 85% effective for PM10 control. This, in our view, confirms the appropriateness of applying the 85% factor noted discussed in the initial paragraph.

Finally, we have also looked at our losses from a mass balance perspective. Conoco knows the average amount of catalyst that it adds to the unit, the average amount of spent catalyst that it sends offsite for reclamation, and the amount of catalyst that is suspended in the heavy oil bottoms from the unit (generally called slurry oil or clarified oil). The balance is unaccounted for losses that are assumed to be stack emissions. Using recent typical data, our mass data shows about 130 tons/year of these unaccounted for losses. In 2000, using the emission factor as above, we estimated about 165 tons/year of particulate emissions, providing further backup to our view that our numbers are conservative.

Therefore, Conoco feels that our use of the most conservative emission rate (340 instead of 242) and a reasonable efficiency factor (85%) results in a very reasonable derived emission factor of 51 pounds particulate per 1000 barrel feed.

I hope that this provides the information that you were looking for to resolve this issue. Thank you for your time in trying to get everyone on the same page.

Jay Christopher
Conoco Inc.
Air Program Leader - Denver
Rocky Mountain Business Unit
303-286-5731 (ETN 473)
303-286-5866 (fax)
jay.s.christopher@usa.conoco.com <jay.s.christopher@usa.conoco.com>

CC: "'jdilley@raqc.org'" <jdilley@raqc.org>

Public Service Company-Arapahoe Station

Table 5-2. Criteria Pollutant Emissions for the Arapahoe Combustion Turbine Project

Pollutant	Total Emissions From Both Turbines	
	lb/hr	tpy[a]
CO	290	90.8
NO_x	62	39.0
SO_2	0.4	0.3
PM_{10}	6	4.0
Pb	0	0

[a]Annual emissions based on an annual heat input of 883,854 MMBTU/year.

Notes:
CO = carbon monoxide
lb/hr = pounds per hour
NO_x = nitrogen oxides
Pb = lead
PM_{10} = fine particulate matter
SO_2 = sulfur dioxide
tpy = tons per year

Emissions exceed the CDPHE thresholds for dispersion modeling analysis for NO_x, and CO. Although the emissions for PM_{10} are below the modeling threshold, a modeling analysis was conducted to verify that the turbines would not cause or contribute to any violation of a PM_{10} NAAQS. Dispersion modeling analyses were conducted for these pollutants, and those analyses are described in detail in later sections of this report.

5.7 On-site PSD Increment Emission Inventory (Item #8 On APCD Review Checklist)

The Arapahoe Combustion Turbine Project is not a major modification, nor will it produce significant impacts of any criteria pollutant, as described in detail in later sections of this report. Therefore, an inventory of on-site increment consuming sources was not required.

Title V

Unit 1
Public Service Company of Colorado, Arapahoe Station
Criteria and HAP Emissions

Stack Identification Code :	S001	Unit Code:	B001

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
25	26	25	24	24	7	8760	0

BOILER SPECIFICATIONS

Furnace Type:	Top-fired wet bottom	
Manufacturer:	Babcock & Wilcox	
Model & Serial #:	NB 16230	
Unit Description:	Top fired with ESP and SO3 gas conditioning	
First Service or Last Mod. Date:	10/7/50	
Max Continuous Rating (MMBtu/hr) :	754.8	Coal
	748.5	Natural Gas

Maximum Hourly Fuel Usage (units/hr)

Fuel Type	Unit	Rate
Bituminous Coal	ton/hr	34
Natural Gas	Mcf/hr	750

STACK DATA

Height (ft)			250
Inside Diameter (ft)			15.75
Exhaust Flow Rate (acfm)			
Normal	204,000	Max	240,000
Velocity (fps)			17.5
Calculated or Stack Test (C/ST)			C
Exhaust Temperature (F)			265
Exhaust Moisture Content (if modified) (%)			
Normal	7	Max	9
Orientation of Release			Up
Rainhat or Other Obstruction			None

Does the boiler/furnace have control technology (Y/N) ? Y

Control	Control Technology, % NOx	PM	SOx
ESP-SO3 conditioning	0	99.03	0

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	C001	2000-406	NONE	2000-407	NONE

OPERATING PARAMETERS

1994		Potential	
Coal (tons) =	136,821	Coal (tons) =	297,840
Max Sulfur Content (%) =	0.50	Max Sulfur Content (%) =	1.00
Max Ash Content (%) =	10.00	Max Ash Content (%) =	10.00
HHV Coal (BTU/lb) =	11,100	HHV Coal (BTU/lb) =	11,100
Natural Gas (Mcf) =	9,113	Natural Gas (Mcf) =	6,570,000
Max Sulfur Content (%) =	NA	Max Sulfur Content (%) =	NA
Max Ash Content (%) =	NA	Max Ash Content (%) =	NA
HHV Gas (BTU/scf) =	998	HHV Gas (BTU/scf) =	998
Operation Hours =	7,985	Operation Hours =	8,760

EMISSION CALCULATIONS

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors Coal	Emission Factors Natural Gas	Actual Emissions (ton/yr)	PTE 100% Coal (ton/yr)	PTE 100% Natural Gas (ton/yr)
NOx	AP-42[1]	lb/ton	21.7		1,487	3,232	
	AP-42[2]	lb/MMCF		550			1,807
CO	AP-42[1]	lb/ton	0.50		34	74	
	AP-42[2]	lb/MMCF		40			131
NMTOC	AP-42[1]	lb/ton	0.06		4	9	
	AP-42[2]	lb/MMCF		1.7			6
PM	AP-42[1]	lb/ton	100.00		66	331	
	AP-42[2]	lb/MMCF		3.00			10
PM_{10}	AP-42[4]	% PM	67.00		44	222	
	AP-42[2]	lb/MMCF		3.00			10
SO_x[3]	AP-42[1]	lb/ton	17.50		1,237	2,606	
	AP-42[2]	lb/MMCF		0.60			2
Antimony							
Arsenic							
Beryllium							
Cadmium							
Chromium							
Cobalt							
Lead	AP-42	lb/10^12 BTU	507	NA	0.007	0.037	NA
Manganese							
Mercury							
Nickel							
Selenium							
Thallium							
Formaldehyde							
POM							

Footnotes

1. Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired
2. Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled
3. Includes SO_3 conditioning emissions
4. PM_{10} is 67% of PM (Electrostatic precipitator controlled emissions, AP-42 Table 1.1-5)

Title V

Unit 2
Public Service Company of Colorado, Arapahoe Station
Criteria and HAP Emissions

Stack Identification Code :	S001	Unit Code:	B002

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
28	30	27	15	24	7	8760	0

BOILER SPECIFICATIONS

Furnace Type:	Top-fired Wet Bottom	
Manufacturer:	Babcock & Wilcox	
Model & Serial #:	NB 16231	
Unit Description:	Top fired with ESP and SO3 gas conditioning	
First Service or Last Mod. Date:	3/1/51	
Max Continuous Rating (MMBtu/hr) :	754.8	Coal
	748.5	Natural Gas

Maximum Hourly Fuel Usage (units/hr)

Fuel Type	Unit	Rate
Bituminous Coal	ton/hr	34
Natural Gas	Mcf/hr	750

STACK DATA

Height (ft)			250
Inside Diameter (ft)			15.75
Exhaust Flow Rate (acfm)			
Normal	204,000	Max	240,000
Velocity (fps)			17.5
Calculated or Stack Test (C/ST)			C
Exhaust Temperature (F)			265
Exhaust Moisture Content (if modified) (%)			
Normal	7	Max	9
Orientation of Release			Up
Rainhat or Other Obstruction			None

			Control Technology, %		
Does the boiler/furnace have control technology (Y/N) ?	Y	Control	NOx	PM	SOx
		ESP-SO3 conditioning	0	97.92	0

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	C002	2000-406	NONE	2000-407	NONE

OPERATING PARAMETERS

1994		Potential	
Coal (tons) =	148,645	Coal (tons) =	297,840
Max Sulfur Content (%) =	0.50	Max Sulfur Content (%) =	1.00
Max Ash Content (%) =	10.00	Max Ash Content (%) =	10.00
HHV Coal (BTU/lb) =	11,100	HHV Coal (BTU/lb) =	11,100
Natural Gas (Mcf) =	6,274	Natural Gas (Mcf) =	6,570,000
Max Sulfur Content (%) =	NA	Max Sulfur Content (%) =	NA
Max Ash Content (%) =	NA	Max Ash Content (%) =	NA
HHV Gas (BTU/scf) =	998	HHV Gas (BTU/scf) =	998
Operation Hours =	7,246	Operation Hours =	8,760

EMISSION CALCULATIONS

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors: Coal	Emission Factors: Natural Gas	Actual Emissions (ton/yr)	PTE 100% Coal (ton/yr)	PTE 100% Natural Gas (ton/yr)
NOx	AP-42[1]	lb/ton	21.7		1,615	3,232	
	AP-42[2]	lb/MMCF		550			1,807
CO	AP-42[1]	lb/ton	0.50		37	74	
	AP-42[2]	lb/MMCF		40			131
NMTOC	AP-42[1]	lb/ton	0.06		4	9	
	AP-42[2]	lb/MMCF		1.7			6
PM	AP-42[1]	lb/ton	100.00		155	331	
	AP-42[2]	lb/MMCF		3.00			10
PM_{10}	AP-42[4]	% PM	67.00		104	222	
	AP-42[2]	lb/MMCF		3.00			10
SO_x[3]	AP-42[1]	lb/ton	17.50		1,341	2,606	
	AP-42[2]	lb/MMCF		0.60			2
Antimony							
Arsenic							
Beryllium							
Cadmium							
Chromium							
Cobalt							
Lead	AP-42	lb/10^12 BTU	507	NA	0.017	0.037	NA
Manganese							
Mercury							
Nickel							
Selenium							
Thallium							
Formaldehyde							
POM							

Footnotes

1. Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired
2. Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled
3. Includes SO_3 conditioning emissions
4. PM_{10} is 67% of PM (Electrostatic precipitator controlled emissions, AP-42 Table 1.1-5)

Title V

Unit 3
Public Service Company of Colorado, Arapahoe Station
Criteria and HAP Emissions

Stack Identification Code :	S002	Unit Code:	B003

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
25	28	24	23	24	7	8760	0

BOILER SPECIFICATIONS			STACK DATA			
Furnace Type:	Top-fired		Height (ft)			250
Manufacturer:	Babcock & Wilcox		Inside Diameter (ft)			15.75
Model & Serial #:	NB 16911		Exhaust Flow Rate (acfm)			
Unit Description:	Top Fired with fabric filter dust collectors(FFDC)		Normal	211,063	Max	255,067
First Service or Last Mod. Date:	11/17/51		Velocity (fps)			18.1
Max Continuous Rating (MMBtu/hr) :	754.8	Coal	Calculated or Stack Test (C/ST)			C
	748.5	Natural Gas	Exhaust Temperature (F)			268
Maximum Hourly Fuel Usage (units/hr)			Exhaust Moisture Content (if modified) (%)			
Fuel Type	Unit	Rate	Normal	7	Max	9
Bituminous Coal	ton/hr	34	Orientation of Release			Up
Natural Gas	Mcf/hr	750	Rainhat or Other Obstruction			None

		Control Technology, %			
		Control	NOx	PM	SOx
Does the boiler/furnace have control technology (Y/N) ?	Y	Baghouse	0	99.9	0

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	C003

OPERATING PARAMETERS

1994		Potential	
Coal (tons) =	141,609	Coal (tons) =	297,840
Max Sulfur Content (%) =	0.50	Max Sulfur Content (%) =	1.00
Max Ash Content (%) =	10.00	Max Ash Content (%) =	10.00
HHV Coal (BTU/lb) =	11,100	HHV Coal (BTU/lb) =	11,100
Natural Gas (Mcf) =	4,742	Natural Gas (Mcf) =	6,570,000
Max Sulfur Content (%) =	NA	Max Sulfur Content (%) =	NA
Max Ash Content (%) =	NA	Max Ash Content (%) =	NA
HHV Gas (BTU/scf) =	998	HHV Gas (BTU/scf) =	998
Operation Hours =	7,925	Operation Hours =	8,760

EMISSION CALCULATIONS

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors Coal	Emission Factors Natural Gas	Actual Emissions (ton/yr)	PTE 100% Coal (ton/yr)	PTE 100% Natural Gas (ton/yr)
NOx	AP-42[1]	lb/ton	21.7		1,538	3,232	
	AP-42[2]	lb/MMCF		550			1,807
CO	AP-42[1]	lb/ton	0.50		35	74	
	AP-42[2]	lb/MMCF		40			131
NMTOC	AP-42[1]	lb/ton	0.06		4	9	
	AP-42[2]	lb/MMCF		1.7			6
PM	AP-42[1]	lb/ton	100.00		7	331	
	AP-42[2]	lb/MMCF		3.00			10
PM_{10}	AP-42[3]	% PM	92.00		7	304	
	AP-42[2]	lb/MMCF		3.00			10
SOx	AP-42[1]	lb/ton	17.50		1,239	2,606	
	AP-42[2]	lb/MMCF		0.60			2
Antimony							
Arsenic							
Beryllium							
Cadmium							
Chromium							
Cobalt							
Lead	AP-42	lb/10^12 BTU	507	NA	0.001	0.037	NA
Manganese							
Mercury							
Nickel							
Selenium							
Thallium							
Formaldehyde							
POM							

Footnotes
1. Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired
2. Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled
3. PM_{10} is 92% of PM (Baghouse controlled emissions, AP-42 Table 1.1-5)

Title V

Unit 4
Public Service Company of Colorado, Arapahoe Station
Criteria and HAP Emissions

Stack Identification Code :	S002	Unit Code:	B004

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
25	26	25	24	24	7	8760	0

BOILER SPECIFICATIONS

Furnace Type:	Top-fired wet bottom with under fire air	
Manufacturer:	Babcock & Wilcox	
Model & Serial #:	HSB 18469	
Unit Description:	Low NOx burner, overfire air, FFDC, DSI	
First Service or Last Mod. Date:	8/22/55	
Max Continuous Rating (MMBtu/hr) :	1709.4	Coal
	1706.58	Natural Gas

Maximum Hourly Fuel Usage (units/hr)

Fuel Type	Unit	Rate
Bituminous Coal	ton/hr	77
Natural Gas	Mcf/hr	1710

STACK DATA

Height (ft)			250
Inside Diameter (ft)			15.75
Exhaust Flow Rate (acfm)			
Normal	384,033	Max	469,812
Velocity (fps)			32.9
Calculated or Stack Test (C/ST)			C
Exhaust Temperature (F)			270
Exhaust Moisture Content (if modified) (%)			
Normal	7	Max	9
Orientation of Release			Up
Rainhat or Other Obstruction			None

		Control Technology, %			
Does the boiler/furnace have control technology (Y/N) ?	Y	Control	NOx	PM	SOx
		Baghouse, Low NOx, & DSI	60.3	99.9	20

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	C004,C005	2000-401	NONE	2000-402	NONE	2000-403	NONE

Cyclones/Settling Chambers		Electrostatic Precipitators		Wet Collection Systems		Baghouses/Fabric Filters	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	C006

OPERATING PARAMETERS

1994		Potential	
Coal (tons) =	323,480	Coal (tons) =	674,520
Max Sulfur Content (%) =	0.50	Max Sulfur Content (%) =	1.00
Max Ash Content (%) =	10.00	Max Ash Content (%) =	10.00
HHV Coal (BTU/lb) =	11,100	HHV Coal (BTU/lb) =	11,100
Natural Gas (Mcf) =	34,237	Natural Gas (Mcf) =	14,979,600
Max Sulfur Content (%) =	NA	Max Sulfur Content (%) =	NA
Max Ash Content (%) =	NA	Max Ash Content (%) =	NA
HHV Gas (BTU/scf) =	998	HHV Gas (BTU/scf) =	998
Operation Hours =	8,490	Operation Hours =	8,760

EMISSION CALCULATIONS

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors Coal	Emission Factors Natural Gas	Actual Emissions (ton/yr)	PTE 100% Coal (ton/yr)	PTE 100% Natural Gas (ton/yr)	
NOx	AP-42[1]	lb/ton	21.7		1,397	4,492		
	AP-42[2]	lb/MMCF		550			4,489	129,290
CO	AP-42[1]	lb/ton	0.50		82	169		
	AP-42[2]	lb/MMCF		40			234	
NMTOC	AP-42[1]	lb/ton	0.06		10	20		
	AP-42[2]	lb/MMCF		1.7			16	
PM	AP-42[1]	lb/ton	100.00		16	749		
	AP-42[2]	lb/MMCF		3.00			748	
PM_{10}	AP-42[3]	% PM	92.00		15	689	748	
	AP-42[2]	lb/MMCF		3.00			~~22~~	
SO_2	AP-42[1]	lb/ton	17.50		2,264	6,589		
	AP-42[2]	lb/MMCF		0.60			2,953	189,545
Antimony								
Arsenic								
Beryllium								
Cadmium								
Chromium								
Cobalt								
Lead	AP-42	lb/10^12 BTU	507	NA	0.002	0.084	NA	
Manganese								
Mercury								
Nickel								
Selenium								
Thallium								
Formaldehyde								
POM								

Footnotes

1. Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, tangentially fired
2. Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, Controlled - Low NOx burners
3. PM_{10} is 92% of PM (Baghouse controlled emissions, AP-42 Table 1.1-5)

Public Service Company-Cherokee Station

Title V

Unit 1
Public Service Company of Colorado, Cherokee Station
Criteria and HAP Emissions

Stack Identification Code :	S001	Emission Unit Code:	B001

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
28	25	27	20	24	7	8,760	0

BOILER SPECIFICATIONS			STACK DATA (S001)			
Furnace Type:	Top Fired		Height (ft)			300
Manufacturer:	Babcock & Wilcox		Inside Diameter (ft)			16
Model & Serial #:	RB 251 NY-771302		Exhaust Flow Rate (acfm)			
Unit Description:	N/A		Normal	789,395	Max	937,595
First Service or Last Mod. Date:	Aug. 12, 1957		Velocity (fps)			65.5
Max Continuous Rating (mmBTU/hr) :	1,392	Coal	Calculated or Stack Test (C/ST)			ST
	1,259	Natural Gas	Exhaust Temperature (F)			265
Maximum Hourly Fuel Usage (units/hr)			Exhaust Moisture Content (if modified) (%)			
Fuel Type	Unit	Rate	Normal	6	Max	10
Bituminous Coal	ton/hr	61.8	Orientation of Release			Up
Natural Gas	mcf/hr	1,240	Rainhat or Other Obstruction			None

Does the boiler/furnace have control technology (Y/N) Y

Control Technology, %			
Control	NOx	PM	SOx
Baghouse	0	99.9	0

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	C001

OPERATING PARAMETERS

1994		Potential	
Coal (ton) =	371,282	Coal (ton) =	541,368
Avg. Sulfur Content (%) =	0.39	Avg. Sulfur Content (%) =	1.00
Avg. Ash Content (%) =	9.95	Avg. Ash Content (%) =	9.95
HHV Coal (BTU/lb) =	11,262	HHV Coal (BTU/lb) =	11,262
Natural Gas (mcf) =	152,312	Natural Gas (mcf) =	10,862,400
Avg. Sulfur Content (%) =	N/A	Avg. Sulfur Content (%) =	N/A
Avg. Ash Content (%) =	N/A	Avg. Ash Content (%) =	N/A
HHV Gas (BTU/scf) =	1,015	HHV Gas (BTU/scf) =	1,015
Operation Hours =	7,771	Operation Hours =	8,760

EMISSION CALCULATIONS

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors Coal	Emission Factors Natural Gas	Actual Emissions (ton/yr)	PTE 100% Coal (ton/yr)	PTE 100% Natural Gas (ton/yr)
NOx	AP-42(1)	lb/ton	21.7		4,070	5,874	
	AP-42(2)	lb/mmCF		550	4077		2,987
CO	AP-42(1)	lb/ton	0.50		96	135	
	AP-42(2)	lb/mmCF		40	92		217
NMTOC	AP-42(1)	lb/ton	0.06		11	16	
	AP-42(2)	lb/mmCF		1.7			9.2
PM	AP-42(1)	lb/ton	99.50		18	610	551
	AP-42(2)	lb/mmCF	16A	3			16
PM_{10}	AP-42(3)	% PM	92.00		17	561	
	AP-42(2)	lb/mmCF		3			16
SOx	AP-42(1)	lb/ton	13.65		2,534	6,707	6065
	AP-42(2)	lb/mmCF	38S = 14.82	0.60	2751		3.3
Antimony							
Arsenic							
Beryllium							
Cadmium							
Chromium							
Cobalt							
Lead	AP-42	lb/10^12 BTU	507	NA	0.015	0.49	NA
Manganese					2.11 tpy	3	
Mercury							
Nickel							
Selenium							
Thallium							
Formaldehyde							
POM							

Footnotes
1. Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired
2. Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled
3. PM10 is 92% of PM (baghouse controlled emissions, AP-42 Table 1.1-5)

What is control factor for Pb?
99.3%

1392 mmBtu/hr / 0.011262 mmBtu/lb × 1 ton/2000 lb = 61.8

Title V

Unit 2
Public Service Company of Colorado, Cherokee Station
Criteria and HAP Emissions

Stack Identification Code :	S001	Emission Unit Code:	B002

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
31	33	11	25	24	7	8,760	0

BOILER SPECIFICATIONS			
Furnace Type:	Top Fired		
Manufacturer:	Babcock & Wilcox		
Model & Serial #:	RB 295 NY-771602		
Unit Description:	N/A		
First Service or Last Mod. Date:	May. 19, 1959		
Max Continuous Rating (mmBTU/hr) :	1,392	Coal	
	1,259	Natural Gas	

Maximum Hourly Fuel Usage (units/hr)		
Fuel Type	Unit	Rate
Bituminous Coal	ton/hr	61.8
Natural Gas	mcf/hr	1,240

STACK DATA (S001)			
Height (ft)			300
Inside Diameter (ft)			16
Exhaust Flow Rate (acfm)			
Normal	789,395	Max	937,595
Velocity (fps)			65.5
Calculated or Stack Test (C/ST)			ST
Exhaust Temperature (F)			265
Exhaust Moisture Content (if modified) (%)			
Normal	6	Max	10
Orientation of Release			Up
Rainhat or Other Obstruction			None

Does the boiler/furnace have control technology (Y/N) Y

Control Technology, %			
Control	NOx	PM	SOx
Baghouse	0	99.9	0

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	C002

OPERATING PARAMETERS

1994		Potential	
Coal (ton) =	261,335	Coal (ton) =	541,368
Avg. Sulfur Content (%) =	0.39	Avg. Sulfur Content (%) =	1.00
Avg. Ash Content (%) =	9.95	Avg. Ash Content (%) =	9.95
HHV Coal (BTU/lb) =	11,262	HHV Coal (BTU/lb) =	11,262
Natural Gas (mcf) =	311,320	Natural Gas (mcf) =	10,862,400
Avg. Sulfur Content (%) =	N/A	Avg. Sulfur Content (%) =	N/A
Avg. Ash Content (%) =	N/A	Avg. Ash Content (%) =	N/A
HHV Gas (BTU/scf) =	1,015	HHV Gas (BTU/scf) =	1,015
Operation Hours =	6,669	Operation Hours =	8,760

EMISSION CALCULATIONS

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors Coal	Emission Factors Natural Gas	Actual Emissions (ton/yr)	PTE 100% Coal (ton/yr)	PTE 100% Natural Gas (ton/yr)
NOx	AP-42(1)	lb/ton	21.7		2,921	5,874	
	AP-42(2)	lb/mmCF		550	2835		2,987
CO	AP-42(1)	lb/ton	0.50		72	135	
	AP-42(2)	lb/mmCF		40	65		217
NMTOC	AP-42(1)	lb/ton	0.06		8.1	16	
	AP-42(2)	lb/mmCF		1.7	7.8		9.2
PM	AP-42(1)	lb/ton	99.50		13	610	551
	AP-42(2)	lb/mmCF	10A	3			16
PM_{10}	AP-42(3)	% PM	92.00		12	561	551
	AP-42(2)	lb/mmCF		3			16
SOx	AP-42(1)	lb/ton	13.65		1,784	6,707	6065
	AP-42(2)	lb/mmCF	365 - 14.82	0.60	1936		3.3
Antimony							
Arsenic			board o.				
Beryllium			355 - subbit				
Cadmium			6000				
Chromium							
Cobalt							
Lead	AP-42	lb/10^12 BTU	507	NA	0.010	0.49	NA
Manganese						3	
Mercury							
Nickel							
Selenium							
Thallium							
Formaldehyde							
POM							

PTE same as for Unit 1

Footnotes
1. Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired
2. Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled
3. PM10 is 92% of PM (baghouse controlled emissions, AP-42 Table 1.1-5)

Title V

Unit 3
Public Service Company of Colorado, Cherokee Station
Criteria and HAP Emissions

Stack Identification Code :	S002	Emission Unit Code:	B003

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
25	27	29	19	24	7	8,760	0

BOILER SPECIFICATIONS

Furnace Type:	Front Fired	
Manufacturer:	Babcock & Wilcox	
Model & Serial #:	RB 344 NY-771802	
Unit Description:	Low NOx burner, with overfire air	
First Service or Last Mod. Date:	Apr. 28, 1962	
Max Continuous Rating (mmBTU/hr) :	1,877	Coal
	1,697	Natural Gas

Maximum Hourly Fuel Usage (units/hr)

Fuel Type	Unit	Rate
Bituminous Coal	ton/hr	83.3
Natural Gas	mcf/hr	1,673

STACK DATA (S002)

Height (ft)				300
Inside Diameter (ft)				19.5
Exhaust Flow Rate (acfm)				
	Normal	495,419	Max	745,517
Velocity (fps)				27.7
Calculated or Stack Test (C/ST)				ST
Exhaust Temperature (F)				267
Exhaust Moisture Content (if modified) (%)				
	Normal	6	Max	10
Orientation of Release				Up
Rainhat or Other Obstruction				None

Does the boiler/furnace have control technology (Y/N) Y

Control	Control Technology, % NOx	PM	SOx
Baghouse & Low NOx	53.5	99.9	0

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	C005	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	C003

OPERATING PARAMETERS

1994		Potential	
Coal (ton) =	425,597	Coal (ton) =	729,708
Avg. Sulfur Content (%) =	0.39	Avg. Sulfur Content (%) =	1.00
Avg. Ash Content (%) =	9.95	Avg. Ash Content (%) =	9.95
HHV Coal (BTU/lb) =	11,262	HHV Coal (BTU/lb) =	11,262
Natural Gas (mcf) =	479,215	Natural Gas (mcf) =	14,655,480
Avg. Sulfur Content (%) =	N/A	Avg. Sulfur Content (%) =	N/A
Avg. Ash Content (%) =	N/A	Avg. Ash Content (%) =	N/A
HHV Gas (BTU/scf) =	1,015	HHV Gas (BTU/scf) =	1,015
Operation Hours =	7,576	Operation Hours =	8,760

EMISSION CALCULATIONS

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors Coal	Emission Factors Natural Gas	Actual Emissions (ton/yr)	PTE 100% Coal (ton/yr)	PTE 100% Natural Gas (ton/yr)
NOx	AP-42(1)	lb/ton	21.7		2,279	4,931	4460
	AP-42(2)	lb/mmCF		550	2147		4,030
CO	AP-42(1)	lb/ton	0.50		116	182	
	AP-42(2)	lb/mmCF		40	106		293
NMTOC	AP-42(1)	lb/ton	0.06		13	22	
	AP-42(2)	lb/mmCF		1.7			12
PM	AP-42(1)	lb/ton	99.50		21	822	743
	AP-42(2)	lb/mmCF	10A	3			22
PM_{10}	AP-42(3)	% PM	92.00		19	756	743
	AP-42(2)	lb/mmCF		3			22
SOx	AP-42(1)	lb/ton	13.65		2,905	9,040	8176
	AP-42(2)	lb/mmCF	385-14.89	0.60	3168		4.4
Antimony							
Arsenic							
Beryllium							
Cadmium							
Chromium							
Cobalt							
Lead	AP-42	lb/10^12 BTU	507	NA	0.017	0.66	NA
Manganese						1.2	
Mercury							
Nickel							
Selenium							
Thallium							
Formaldehyde							
POM							

Footnotes

1. Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, wall fired
2. Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled
3. PM10 is 92% of PM (baghouse controlled emissions, AP-42 Table 1.1-5)

low NOx burner 53.5% control eff.

Title V

Unit 4
Public Service Company of Colorado, Cherokee Station
Criteria and HAP Emissions

Stack Identification Code :	S003	Emission Unit Code:	B004

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
25	24	27	24	24	7	8,760	0

BOILER SPECIFICATIONS			STACK DATA (S003)			
Furnace Type:	Corner tilting tangential firing		Height (ft)			400
Manufacturer:	Combustion Engineering		Inside Diameter (ft)			22
Model & Serial #:	12465 C400016		Exhaust Flow Rate (acfm)			
Unit Description:	Low NOx burner, with overfire air		Normal	1,041,916	Max	1,389,927
First Service or Last Mod. Date:	Nov. 20, 1968		Velocity (fps)			45.7
Max Continuous Rating (mmBTU/hr) :	3,520	Coal	Calculated or Stack Test (C/ST)			C
	3410 ~~3,552~~	Natural Gas	Exhaust Temperature (F)			267
Maximum Hourly Fuel Usage (units/hr)			Exhaust Moisture Content (if modified) (%)			
Fuel Type	Unit	Rate	Normal	6	Max	10
Bituminous Coal	ton/hr	~~156.3~~	Orientation of Release			Up
Natural Gas	mcf/hr	1749 3468	Rainhat or Other Obstruction			None

			Control Technology, %		
		Control	NOx	PM	SOx
Does the boiler/furnace have control technology (Y/N)	Y	Baghouse, Low NOx, & DSI	62	99.9	37.5

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	C006, C007	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	C004

OPERATING PARAMETERS

1994		Potential	
Coal (ton) =	981,255	Coal (ton) =	1,369,188
Avg. Sulfur Content (%) =	0.39	Avg. Sulfur Content (%) =	1.00
Avg. Ash Content (%) =	9.95	Avg. Ash Content (%) =	9.95
HHV Coal (BTU/lb) =	11,262	HHV Coal (BTU/lb) =	11,262
Natural Gas (mcf) =	333,192	Natural Gas (mcf) =	15,321,240 — 30,379,680
Avg. Sulfur Content (%) =	N/A	Avg. Sulfur Content (%) =	N/A
Avg. Ash Content (%) =	N/A	Avg. Ash Content (%) =	N/A
HHV Gas (BTU/scf) =	1,015	HHV Gas (BTU/scf) =	1,015
Operation Hours =	8,102	Operation Hours =	8,760

EMISSION CALCULATIONS

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors Coal	Emission Factors Natural Gas	Actual Emissions (ton/yr)	PTE 100% Coal (ton/yr)	PTE 50% Coal/50%Gas (ton/yr)	PTE 100% Gas
NOx	AP-42(1)	lb/ton	14.4		276 ~~2,776~~	6,939		6,939
	AP-42(2)	lb/mmCF		550	2684		6,969	
CO	AP-42(1)	lb/ton	0.50		252	342		607
	AP-42(2)	lb/mmCF		40	246		478	
NMTOC	AP-42(1)	lb/ton	0.06		30	41		26
	AP-42(2)	lb/mmCF		1.7			34	
PM	AP-42(1)	lb/ton	99.50		49	1,542		1542
	AP-42(2)	lb/mmCF	10A	3			794	
PM_{10}	AP-42(3)	% PM	92.00		45	1,419		1542
	AP-42(2)	lb/mmCF		3			732	
SOx	AP-42(1)	lb/ton	13.65		~~4,186~~	16,962		16962
	AP-42(2)	lb/mmCF	38S-1489	0.60	4565		8,485	
Antimony								
Arsenic			based on 35-Sub-bit coal					
Beryllium								
Cadmium								
Chromium								
Cobalt								
Lead	AP-42	lb/10^12 BTU	507	NA	0.039	~~1.2~~ 1.8	0.62	
Manganese								
Mercury								
Nickel								
Selenium								
Thallium								
Formaldehyde								
POM								

SO2 control device 37.5% eff

Footnotes
1. Section 1.1 Bituminous and Subbituminous Coal Combustion; Pulverized coal fired, dry bottom, tangentially fired
2. Section 1.4 Natural Gas Combustion; Utility/large industrial boilers, uncontrolled
3. PM10 is 92% of PM (baghouse controlled emissions, AP-42 Table 1.1-5)

625

low NOx burner 62% control eff

Public Service Company-Valmont Station

TABLE 3-1
Valmont Combustion Turbine Project Emissions Summary [a]

Pollutant	Significant Emission Rates (tpy)	Annual Emissions (tpy), Total of Both Turbines plus Unit #8 Air Preheater [b]	Maximum Hourly Emissions (lb/hr), Each of Two Turbines[c]	Maximum Hourly Emissions (lb/hr), Unit #8 Air Preheater
Carbon Monoxide	100	90.8	220	0.24
Nitrogen Oxides	40	39.1	31	0.24
Sulfur Dioxide [d]	40	0.3	0.2	0.01
Particulate Matter [e]	25	4.0	3	0.04
Fine Particulate Matter PM_{10} [e]	15	4.0	3	0.04
Ozone	40 (voc)	1.5	5.1	0.04
Lead	0.6	Not Emitted	Not Emitted	Not Emitted
Fluorides	3	Not Emitted	Not Emitted	Not Emitted
Sulfuric Acid Mist	7	Not Emitted	Not Emitted	Not Emitted
Total Reduced Sulfur	10	Not Emitted	Not Emitted	Not Emitted
Reduced Sulfur Compounds	10	Not Emitted	Not Emitted	Not Emitted
Formaldehyde	Not Applicable	0.3	0.2	0.0005
Total HAPs	Not Applicable	0.6	0.4	0.01

[a]Detailed emission calculations are provided in Appendix A.

[b]Annual emissions are based on total heat inputs for the Unit #7 turbine of 442,000 MMBtu per year, for the Unit #8 turbine of 442,000 MMBtu/year, and the Unit #8 air preheater of 6,700 MMBtu/year.

[c]Hourly emissions are based on operating conditions that result in maximum emissions for each pollutant. For sulfur dioxide, particulate matter, and fine particulate matter, these conditions are: operation at full load across all ambient temperatures. For carbon monoxide, oxides of nitrogen, and volatile organic compounds, maximum emitting conditions are: 100 percent load at 25 degrees Fahrenheit.

[d]The SO_2 emissions were estimated from the EPA default emissions rate of 0.0006 pounds SO_2 per MMBtu, for combustion turbine burning pipeline quality natural gas as obtained from 40 CFR 75, Appendix D, 2.3.2.

[e]The PM and PM_{10} emissions are the sum of solid and condensable fractions.

Notes:
tpy = tons per year
lb/hr = pounds per hour

Public Service Company-Zuni Station

Unit 1A
Public Service Company of Colorado, Zuni Station
Criteria and HAP Emissions

Stack Identification Code:	S001	Unit Code:	B001

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
41	16	20	23	24	7	8760	0

BOILER SPECIFICATIONS			STACK DATA	
Furnace Type:	Front-fired		Height (ft)	280
Manufacturer:	Babcock & Wilcox		Inside Diameter (ft)	13
Model & Serial #:	15253		Exhaust Flow Rate (ACFM)	
Unit Description:	N/A		Normal 120,000 Max	240,000
First Service or Last Mod. Date:	1948		Exhaust Velocity (fps)	15.08
Max Continuous Rating (MMBTU/hr):	450	Natural Gas	Calculated or Stack Test (C/ST)	ST
	450	#6 Fuel Oil	Exhaust Temperature (F)	500
Maximum Hourly Fuel Usage (units/hr)			Exhaust Moisture Content (if modified) (%)	
Fuel Type	Unit	Rate	Normal 10 Max	16
Natural Gas	Mcf/hr	450	Orientation of Release	Up
#6 Fuel Oil	gal/hr	3,061	Rainhat or Other Obstruction	None

Does the boiler/furnace have control technology (Y/N) N

Control Technology, %			
Control	NOx	PM	SOx
None	0	0	0

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		Electrostatic Precipitators		Wet Collection Systems		Baghouses/Fabric Filters	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	NONE

OPERATING PARAMETERS

1994		Potential	
Natural Gas (Mcf) =	508,496	Natural Gas (Mcf) =	3,942,000
Max Sulfur Content (%) =	0.01	Max Sulfur Content (%) =	0.01
Max Ash Content (%) =	0.00	Max Ash Content (%) =	0.00
HHV Gas (BTU/cf) =	1,000	HHV Gas (BTU/cf) =	1,000
#6 Fuel Oil (gal) =	2,650	#6 Fuel Oil (gal) =	26,816,327
Max Sulfur Content (%) =	0.79	Max Sulfur Content (%) =	0.79
Max Ash Content (%) =	0.1	Max Ash Content (%) =	0.1
HHV Fuel Oil (MBTU/gal) =	147	HHV Fuel Oil (MBTU/gal) =	147
Operation Hours =	3,459	Operation Hours =	8,760

EMISSION CALCULATIONS

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors Natural Gas	Emission Factors #6 Fuel Oil	Actual Emissions (ton/yr)	PTE 100% Natural Gas (ton/yr)	PTE 100 % #6 Fuel Oil (ton/yr)
NOx	AP-42(1)	lb/MMCF	550		140	1,084	
	AP-42(4)	lb/10^3 gal		67			898
CO	AP-42(1)	lb/MMCF	40		10.2	79	
	AP-42(4)	lb/10^3 gal		5			67
NMTOC	AP-42(3)	lb/MMCF	1.7		0.43	3.4	
	AP-42(5)	lb/10^3 gal		0.76			10
PM	AP-42(2)	lb/MMCF	3.0		0.78	5.9	
	AP-42(4)	lb/10^3 gal		10.48			141
PM_{10}	AP-42(2)	lb/MMCF	3.0		0.55	5.9	
	AP-42(6)	% PM		71			100
SOx	AP-42(1)	lb/MMCF	0.6		0.32	1.2	
	AP-42(4)	lb/10^3 gal		129			1,577
Antimony							
Arsenic							
Beryllium							
Cadmium							
Chromium							
Cobalt							
Lead	AP-42	lb/10^12 BTU	NA	111	0.0000	NA	0.22
Manganese							
Mercury							
Nickel							
Selenium							
Thallium							
Formaldehyde							
POM							

Footnotes

1. Section 1.4, Natural Gas Combustion; Table 1.4-2.
2. Section 1.4, Natural Gas Combustion; Table 1.4-1.
3. Section 1.4, Natural Gas Combustion; Table 1.4-3.
4. Section 1.3 Fuel Oil Combustion; Table 1.3-2.
5. Section 1.3, Fuel Oil Combustion; Table 1.3-4.
6. PM_{10} is 71% of PM (uncontrolled PM emissions AP-42, Table 1.3-5)

Unit 1B
Public Service Company of Colorado, Zuni Station
Criteria and HAP Emissions

Stack Identification Code :	S002	Unit Code:	B002

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
41	16	20	23	24	7	8760	0

BOILER SPECIFICATIONS			STACK DATA	
Furnace Type:	Front fired		Height (ft)	107
Manufacturer:	Babcock & Wilcox		Inside Diameter (ft)	6
Model & Serial #:	15265		Exhaust Flow Rate (acfm)	
Unit Description:	N/A		Normal 120,000 Max	204,000
First Service or Last Mod. Date:	1948		Exhaust Velocity (fps)	70.77
Max Continuous Rating (MMBtu/hr) :	200	Natural Gas	Calculated or Stack Test (C/ST)	ST
	200	#6 Fuel Oil	Exhaust Temperature (F)	500
Maximum Hourly Fuel Usage (units/hr)			Exhaust Moisture Content (if modified) (%)	
Fuel Type	Unit	Rate	Normal 10 Max	16
Natural Gas	mcf/hr	200	Orientation of Release	Up
#6 Fuel Oil	gal/hr	1,361	Rainhat or Other Obstruction	None

		Control Technology, %			
Does the boiler/furnace have control technology (Y/N)	N	Control	NOx	PM	SOx
		None	0	0	0

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	NONE

OPERATING PARAMETERS

1994		Potential	
Natural Gas (Mcf) =	63,537	Natural Gas (Mcf) =	1,752,000
Max Sulfur Content (%) =	0.01	Max Sulfur Content (%) =	0.01
Max Ash Content (%) =	0.00	Max Ash Content (%) =	0.00
HHV Gas (BTU/cf) =	1,000	HHV Gas (BTU/cf) =	1,000
#6 Fuel Oil (gal) =	0	#6 Fuel Oil (gal) =	11,918,367
Max Sulfur Content (%) =	0.79	Max Sulfur Content (%) =	0.79
Max Ash Content (%) =	0.1	Max Ash Content (%) =	0.1
HHV Fuel Oil (MBTU/gal) =	147	HHV Fuel Oil (MBTU/gal) =	147
Operation Hours =	500	Operation Hours =	8,760

EMISSION CALCULATIONS

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors Natural Gas	Emission Factors #6 Fuel Oil	Actual Emissions (ton/yr)	PTE 100% Natural Gas (ton/yr)	PTE 100 % #6 Fuel Oil (ton/yr)
NOx	AP-42(1)	lb/MMCF	550		17	482	
	AP-42(4)	lb/10^3 gal		67			399
CO	AP-42(1)	lb/MMCF	40		1.3	35	
	AP-42(4)	lb/10^3 gal		5			30
NMTOC	AP-42(3)	lb/MMCF	1.7		0.05	1.5	
	AP-42(5)	lb/10^3 gal		0.76			4.5
PM	AP-42(2)	lb/MMCF	3.0		0.10	2.6	
	AP-42(4)	lb/10^3 gal		10.48			62
PM_{10}	AP-42(2)	lb/MMCF	3.0		0.07	2.6	
	AP-42(6)	% PM		71			44
SOx	AP-42(1)	lb/MMCF	0.60		0.02	0.53	
	AP-42(4)	lb/10^3 gal		128.53			701
Antimony							
Arsenic							
Beryllium							
Cadmium							
Chromium							
Cobalt							
Lead	AP-42	lb/10^12 BTU	NA	111	0.0000	NA	0.097
Manganese							
Mercury							
Nickel							
Selenium							
Thallium							
Formaldehyde							
POM							

Footnotes

1. Section 1.4, Natural Gas Combustion; Table 1.4-2.
2. Section 1.4, Natural Gas Combustion; Table 1.4-1.
3. Section 1.4, Natural Gas Combustion; Table 1.4-3.
4. Section 1.3 Fuel Oil Combustion; Table 1.3-2.
5. Section 1.3, Fuel Oil Combustion; Table 1.3-4.
6. PM_{10} is 71% of PM (uncontrolled PM emissions AP-42, Table 1.3-5)

Unit 2
Public Service Company of Colorado, Zuni Station
Criteria and HAP Emissions

Stack Identification Code : S003 | Unit Code: B003

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
33	37	28	2	24	7	8760	0

BOILER SPECIFICATIONS

Furnace Type:	Two-Drumb Boiler	
Manufacturer:	Babcock & Wilcox	
Model & Serial #:	17869	
Unit Description:	N/A	
First Service or Last Mod. Date:	1953	
Max Continuous Rating (MMBTU/hr) :	1075	Natural Gas
	1075	#6 Fuel Oil

Maximum Hourly Fuel Usage (units/hr)

Fuel Type	Unit	Rate
Natural Gas	Mcf/hr	1,075
#6 Fuel Oil	gal/hr	7,313

STACK DATA

Height (ft)			250
Inside Diameter (ft)			12
Exhaust Flow Rate (ACFM)			
Normal	210,000	Max	580,000
Exhaust Velocity (fps)			30.96
Calculated or Stack Test (C/ST)			ST
Exhaust Temperature (F)			500
Exhaust Moisture Content (if modified) (%)			
Normal	10	Max	16
Orientation of Release			Up
Rainhat or Other Obstruction			None

Does the boiler/furnace have control technology (Y/N) N

	Control Technology, %		
Control	NOx	PM	SOx
None	0	0	0

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		Electrostatic Precipitators		Wet Collection Systems		Baghouses/Fabric Filters	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	NONE

OPERATING PARAMETERS

1994		Potential	
Natural Gas (Mcf) =	139,073	Natural Gas (Mcf) =	9,417,000
Max Sulfur Content (%) =	0.01	Max Sulfur Content (%) =	0.01
Max Ash Content (%) =	0.00	Max Ash Content (%) =	0.00
HHV Gas (BTU/cf) =	1,000	HHV Gas (BTU/cf) =	1,000
#6 Fuel Oil (gal) =	30	#6 Fuel Oil (gal) =	64,061,224
Max Sulfur Content (%) =	0.79	Max Sulfur Content (%) =	0.79
Max Ash Content (%) =	0.1	Max Ash Content (%) =	0.1
HHV Fuel Oil (MBTU/gal) =	147	HHV Fuel Oil (MBTU/gal) =	147
Operation Hours =	130	Operation Hours =	8,760

EMISSION CALCULATIONS

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors		Actual Emissions (ton/yr)	PTE 100% Natural Gas (ton/yr)	PTE 100 % #6 Fuel Oil (ton/yr)
			Natural Gas	#6 Fuel Oil			
NOx	AP-42(1) AP-42(4)	lb/MMCF lb/10^3 gal	550	67	38	2,590	2,146
CO	AP-42(1) AP-42(4)	lb/MMCF lb/10^3 gal	40	5	2.8	188	160
NMTOC	AP-42(3) AP-42(5)	lb/MMCF lb/10^3 gal	1.7	1	0.12	8.0	24
PM	AP-42(2) AP-42(4)	lb/MMCF lb/10^3 gal	3.0	10.48	0.21	14	336
PM_{10}	AP-42(2) AP-42(6)	lb/MMCF % PM	3.0	71	0.15	14	238
SOx	AP-42(1) AP-42(4)	lb/MMCF lb/10^3 gal	0.60	128.53	0.044	2.8	3,767
Antimony							
Arsenic							
Beryllium							
Cadmium							
Chromium							
Cobalt							
Lead	AP-42	lb/10^12 BTU	NA	111	0.0000	NA	0.52
Manganese							
Mercury							
Nickel							
Selenium							
Thallium							
Formaldehyde							
POM							

Footnotes

1. Section 1.4, Natural Gas Combustion; Table 1.4-2.
2. Section 1.4, Natural Gas Combustion; Table 1.4-1.
3. Section 1.4, Natural Gas Combustion; Table 1.4-3.
4. Section 1.3 Fuel Oil Combustion; Table 1.3-2.
5. Section 1.3, Fuel Oil Combustion; Table 1.3-4.
6. PM_{10} is 71% of PM (uncontrolled PM emissions AP-42, Table 1.3-5)

Robinson Brick

FOR THE RECORD

January 31, 2001

BY: Mike Jensen

Ref: Robinson Brick FID 0311447 97OPDE189

SUBJECT: PM10 PTE Review

On Friday, January 26, 2001, Mike Silverstein, APCD, called and asked for the PTE numbers for Robinson Brick. I gave him the numbers from the TRD. A copy of that page of the TRD is attached to this review for future reference as needed.

Gerry Dilley (303-629-5450 X240) from the RAQC called yesterday with a request for information about how the PTE for the PM10 for Robinson Brick was calculated. I reviewed the file and compiled the following information. The process design rates are taken from the Title V submittal. A copy of the summary page is attached to this review for future reference as needed. Emission factors shown were taken from the Title V permit. Reg 1 sets a particulate matter hourly limit for some sources. This limit would be an upper boundary in that while PM10 may be a fraction of the PM, it can not exceed the PM.

F001/F005 Loader/Storage Piles/Unpaved Roads

This is all fugitive dust and not included in the facility PTE
Material Transfer: 0.1 X 0.35 = 0.04 TPY
Storage Piles: 24.9 X 0.35 = 8.72 TPY
Total: 8.76 TPY

F002 Primary Crusher

Reg 1 = $17.31(90)^{0.16}$ = 35.56 lb/hr
35.56 lb/hr X 8760 hr/yr X ton/2000 lb = 35.56 X 4.38 = 155.8 TPY

Design Rate: 90 ton/hr X 0.059 lb/ton X 4.38 hr-ton/yr-lb = 23.25 TPY **PTE = 23.3 TPY**

F003 Grinding/Screening

Reg 1 = $17.31(90)^{0.16}$ = 35.56 lb/hr
35.56 lb/hr X 4.38 hr-ton/yr-lb = 155.8 TPY

Design Rate: 90 ton/hr X 0.0265 lb/ton X 4.38 hr-ton/yr-lb = 10.45 TPY

Permit Limit: 4.7 TPY **PTE = 4.7 TPY**

F004 Conveyor
Reg 1 = $17.31(90)^{0.16}$ = 35.56 lb/hr
35.56 lb/hr X 4.38 hr-ton/yr-lb = 155.8 TPY

Design Rate: 90 ton/hr X 0.00029 lb/ton X 4.38 hr-ton/yr-lb = 0.11 TPY **PTE = 0.11 TPY**

S001 Rotary Dryer
Reg 1 = $17.31(35)^{0.16}$ = 30.57 lb/hr
30.57 lb/hr X 4.38 hr-ton/yr-lb = 133.9 TPY

Design Rate: 35 ton/hr X 0.16 lb/ton X 4.38 hr-ton/yr-lb = 24.53 TPY **PTE = 24.5 TPY**

S002 – S005 Two Tunnel Dryers & two kilns

Reg 1 = $3.59(13.4)^{0.62}$ = 17.9 lb/hr
17.9 lb/hr X 4.38 hr-ton/yr-lb = 78.59 TPY per line X 2 = 157.18 TPY

From Title V = 199,000 ton/yr X 0.87 lb/ton X ton/2000 lb = 86.6 TPY

Permit Limit = 130.8 TPY **PTE = 130.8 TPY**

S006 Rotary Calciner
Reg 1 = $3.59(10.0)^{0.62}$ = 14.9 lb/hr
14.9 lb/hr X 4.38 hr-ton/yr-lb = 65.5 TPY

Design Rate: 10 ton/hr X 0.3 lb/ton X 4.38 hr-ton/yr-lb = 13.14 TPY **PTE = 13.14 TPY**

PTE SUMMARY

F002	Primary Crusher	23.3 TPY
F003	Grinding/Screening	4.7
F004	Conveyor	0.11
S001	Rotary Dryer	24.5
S002-S005	Two Tunnel Dryers and kilns	130.8
S006	Rotary Calciner	13.1
TOTAL		**196.5 TPY**

Rocky Mountain Bottle Company

Trigen-Colorado Energy Corporation

Facility-wide emissions are as follows:

		POTENTIAL TO EMIT, TONS PER YEAR						
		PM	PM_{10}	SO_2	NOx	VOC	CO	HAPs
B001 - 288 MMBtu/hr								
	NG	9.4	9.4	0.74	346.3	10.8	103.9	
	#2 FO	18.02	9.01	410.2	216.3	1.8	45.1	
B002 - 288 MMBtu/hr								
	NG	9.4	9.4	0.74	346.3	10.8	103.9	
	#2 FO	18.02	9.01	410.2	216.3	1.8	45.1	
B003 - 225 MMBtu/hr, Coal		2852.8	570.6	1512.83	380.4	2.16	216.1	
B004 - 360 MMBtu/hr,								
	Permit	158.0	158.0	1892.0	1104.0	19.21	88.30	
	Coal*	5268.55	1218.92	2650.05	639.36	4.86	39.55	
	NG	16.45	16.45	1.30	367.92	18.83	51.94	
	#2 FO	28.03	14.02	638.15	336.38	2.80	70.08	
B005 - 650 MMBtu/hr,								
	Permit	285.0	285.0	3416.0	1993.0	9.50	103.1	
	Coal*	11084.15	2556.71	5557.73	1346.16	10.02	82.62	
	NG	21.21	21.21	1.67	474.50	24.28	66.99	
	#2 FO	40.67	20.34	925.89	488.06	4.07	101.68	
M001/C004 - Rail car dumper to hoppers		51.6	51.6					
M001/C005 - Dumper to transfer conveyor								
M001/C006 - Conveyor to Unit 4 silos								
M001/C008 - Conveyor to Unit 5 silos		22.7	22.7					

RECEIVED

FEB 2 2 2000

AIR POLLUTION CONTROL DIVISION
STATIONARY SOURCES PROGRAM

Unit 1
TRIGEN-COLORADO ENERGY CORPORATION
Criteria and HAP Emissions from Natural Gas or Fuel Oil

Stack Identification Code :	S001	Unit Code:	B001

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
25	25	25	25	24	7	8760	0

BOILER SPECIFICATIONS		STACK DATA			
Furnace Type:	Wall Fired	Height (ft)			130
Manufacturer:	Combustion Engineering	Inside Diameter (ft)			8
Model & Serial #:	CE-VU40, 17047	Exhaust Flow Rate (ACFM)			
Unit Description:	External Combustion Wall-Fired Boiler	Normal	110,000	Max	120,637
First Service or Last Mod. Date:	1967	Exhaust Velocity (fps) at MCR			40.00
Maximum Continuous Rating: (MMBTU/HR)	288 Natural Gas or #2 Fuel Oil	Calculated or Stack Test (C/ST)			ST
		Exhaust Temperature (F)			380
		Exhaust Moisture Content (if modified) (%)			
		Normal	10	Max	16
		Orientation of Release			Up
		Rainhat or Other Obstruction			None

Maximum Hourly Fuel Usage (units/hr)

Fuel Type	Unit	Rate
Natural Gas	Mcf/hr	271
#2 Fuel Oil	gal/hr	2,075

Does the boiler/furnace have control technology (Y/ N

	Control Technology, %		
Control Devic	NOx	PM	SOx
None	0	0	0

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	NONE

OPERATING PARAMETERS

1994 Revised		Potential	
Btu corrected Natural Gas (Mcf) =	210,746	Btu corrected Natural Gas (Mcf) =	2,373,960
Avg. Sulfur Content (%) =	0.01	Avg. Sulfur Content (%) =	0.01
Avg. Ash Content (%) =	0.00	Avg. Ash Content (%) =	0.00
HHV Gas (Btu/SCF) =	1,064	HHV Gas (Btu/SCF) =	1,064
#2 Fuel Oil (gal) =	0	#2 Fuel Oil (gal) =	18,177,000
Btu corrected Fuel Oil (gals) =	0	Btu corrected Fuel Oil (gals) =	18,021,197
Avg. Sulfur Content (%) =	0.29	Avg. Sulfur Content (%) =	0.29
Avg. Ash Content (%) =	0.01	Avg. Ash Content (%) =	0.01
HHV Oil (Btu/gal) =	138,800	HHV Oil (Btu/gal) =	138,800
Operation Hours =	8,544	Operation Hours =	8,760

EMISSION CALCULATIONS — Unit 1

Pollutant	Source of Emission Factor/CEM	Units of Emission Factor	Emission Factors Natural Gas	Emission Factors #2 Fuel Oil	Actual Emissions (ton/yr)	PTE 100% Natural Gas (ton/yr)	PTE 100 % #2 Fuel Oil (ton/yr)
NOx	AP-42[8]	lb/MMCF	280		29.50	332	
	AP-42[10]	lb/10^3 gal		24	0.0		216
			Total Calculated Emissions:		**29.50**		
CO	AP-42[8]	lb/MMCF	84		8.85	100	
	AP-42[10]	lb/10^3 gal		5	0.00		45
			Total Calculated Emissions:		**8.851**		
TNMOC	AP-42[9]	lb/MMCF	8.7		0.9167	10.33	
	AP-42[11]	lb/10^3 gal		0.20	0.000		2
			Total Calculated Emissions:		**0.917**		
PM	AP-42[9]	lb/MMCF	7.6		0.8008	9.02	
	AP-42[10]	lb/10^3 gal		2	0.0000		18
			Total Calculated Emissions:		**0.8008**		
PM10	AP-42[9]	lb/MMCF	7.6		0.8008	9.02	
	AP-42[12]	lb/10^3 gal		1	0.0000		9
			Total Calculated Emissions:		**0.8008**		
SOx	AP-42[9]	lb/MMCF	0.60		0.063	0.71	
	AP-42[10]	lb/10^3 gal		45.53	0.000		410
			Total Calculated Emissions:		**0.063**		

Unit 2

TRIGEN-COLORADO ENERGY CORPORATION

Criteria and HAP Emissions from Natural Gas or Fuel Oil

Stack Identification Code :	S002	Unit Code:	B002

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
25	25	25	25	24	7	8760	0

BOILER SPECIFICATIONS			STACK DATA			
Furnace Type:	Wall Fired		Height (ft)			130
Manufacturer:	Combustion Engineering		Inside Diameter (ft)			8
Model & Serial #:	CE-VU40, 17049		Exhaust Flow Rate (ACFM)			
Unit Description:	External Combustion Wall-Fired Boiler		Normal	110,000	Max	120,637
First Service or Last Mod. Date:	1967		Exhaust Velocity (fps) at MCR			40.00
Maximum Continuous Rating: (MMBTU/HR)	288	Natural Gas or #2 Fuel Oil	Calculated or Stack Test (C/ST)			ST
			Exhaust Temperature (F)			380
Maximum Hourly Fuel Usage (units/hr)			Exhaust Moisture Content (if modified) (%)			
Fuel Type	Unit	Rate	Normal	10	Max	16
Natural Gas	Mcf/hr	271	Orientation of Release			Up
#2 Fuel Oil	gal/hr	2,075	Rainhat or Other Obstruction			None

		Control Technology, %		
Does the boiler/furnace have control technology (Y/ N	Control Devic	NOx	PM	SOx
	None	0	0	0

Miscellaneous		Condensers		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	NONE

OPERATING PARAMETERS

1994 Revised		Potential		
Btu corrected Natural Gas (Mcf) =	200,792	Btu corrected Natural Gas (Mcf) =	2,372,960	
Avg. Sulfur Content (%) =	0.01	Avg. Sulfur Content (%) =	0.01	
Avg. Ash Content (%) =	0.00	Avg. Ash Content (%) =	0.00	
HHV Gas (Btu/SCF) =	1,064	HHV Gas (Btu/SCF) =	1,064	
#2 Fuel Oil (gal) =	291,439	#2 Fuel Oil (gal) =	18,177,000	1
Btu corrected Fuel Oil (gals) =	288,941	Btu corrected Fuel Oil (gals) =	18,021,197	
Avg. Sulfur Content (%) =	0.29	Avg. Sulfur Content (%) =	0.29	
Avg. Ash Content (%) =	0.01	Avg. Ash Content (%) =	0.01	
HHV Oil (Btu/gal) =	138,800	HHV Oil (Btu/gal) =	138,800	
Operation Hours =	7,920	Operation Hours =	8,760	

EMISSION CALCULATIONS — Unit 2

Pollutant	Source of Emission Factor/CEM	Units of Emission Factor	Emission Factors: Natural Gas	Emission Factors: #2 Fuel Oil	Actual Emissions (ton/yr)	PTE 100% Natural Gas (ton/yr)	PTE 100 % #2 Fuel Oil (ton/yr)
NOx	AP-42[8]	lb/MMCF	280		28.1	332	
	AP-42[10]	lb/10^3 gal		24	3.5		216
			Total Calculated Emissions:		**31.58**		
CO	AP-42[8]	lb/MMCF	84		8.43	100	
	AP-42[10]	lb/10^3 gal		5	0.72		45
			Total Calculated Emissions:		**9.156**		
TNMOC	AP-42[9]	lb/MMCF	8.7		0.8734	10	
	AP-42[11]	lb/10^3 gal		0.20	0.029		2
			Total Calculated Emissions:		**0.902**		
PM	AP-42[9]	lb/MMCF	7.6		0.7630	9	
	AP-42[10]	lb/10^3 gal		2	0.2889		18
			Total Calculated Emissions:		**1.052**		
PM10	AP-42[9]	lb/MMCF	7.6		0.7630	9	
	AP-42[12]	lb/10^3 gal		1	0.1445		9
			Total Calculated Emissions:		**0.907**		
SOx	AP-42[9]	lb/MMCF	0.60		0.060	1	
	AP-42[10]	lb/10^3 gal		45.53	6.578		410
			Total Calculated Emissions:		**6.638**		

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STATIONARY SOURCES PROGRAM

Unit 3
TRIGEN-COLORADO ENERGY CORPORATION
Criteria and HAP Emissions

Stack Identification Code : S003 | Unit Code: B003

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
25	25	25	25	24	7	8,760	0

BOILER SPECIFICATIONS

Furnace Type: Treveling Grate Spreader-Stoker
Manufacturer: Combustion Engineering
Model & Serial #: CE-VU40, 17051
Unit Description: External Combustion Coal-fired Stoker Boiler
First Service or Last Mod. Date: 1981
Maximum Continuous Rating: 225.0 Coal
(MMBTU/HR)

Maximum Hourly Fuel Usage (units/hr)

Fuel Type	Unit	Rate
SubBituminous Coal	ton/hr	9.90

STACK DATA

Height (ft) 130
Inside Diameter (ft) 8
Exhaust Flow Rate (acfm)
Normal 100,000 Max 105,558
Exhaust Velocity (fps) at MCR 35.00
Calculated or Stack Test (C/ST) ST
Exhaust Temperature (F) 360
Exhaust Moisture Content (if modified) (%)
Normal NA Max NA
Orientation of Release Up
Rainhat or Other Obstruction None

Does the boiler/furnace have control technology (Y/ Y

Control Technology and Efficiency (%)

Control Devi	NOx	PM	SOx	
Baghouse	0	99.9	0	[redacted]

Miscellaneous		Condensors		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	C001

OPERATING PARAMETERS

1994 Revised		Potential	
Sub Bit Coal Fired (tons) =	47,876	Sub Bit Coal Fired (tons) =	86,724
Avg. Sulfur Content (%) =	0.45	Avg. Sulfur Content (%) =	1
Avg. Ash Content (%) =	7.00	Avg. Ash Content (%) =	7
HHV Coal (Btu/lb) =	11,400	HHV Coal (Btu/lb) =	11,400
Operation Hours =	7,752	Operation Hours =	8,760

EMISSION CALCULATIONS **Unit 3**

Pollutant	Source of Emission Factor	Units of Emission Factor	Emission Factors Coal			Actual Emissions (tpy)	PTE 100% Coal (tpy)		
NOx	AP-42[1]	lb/ton	8.8			211	382		
CO	AP-42[1]	lb/ton	5.00			120	217		
NMTOC	AP-42[1]	lb/ton	0.05			1	2		
PM	AP-42[1]	lb/ton	66.00			2	121		
PM10	AP-422]	lb/ton	13.20			0	111		
SOx	AP-42[1]	lb/ton	15.8			377	1,774		

Unit 4

TRIGEN-COLORADO ENERGY CORPORATION

Criteria and HAP Emissions from Coal, Alcohol, and Waste Oil

Stack Identification Code : S004 | Unit Code: B004

Seasonal Fuel Usage (%)			
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov
25	25	25	25

Normal Operation of Unit			Space Heat (%)
Hours/Day	Days/Week	Hours/year	
24	7	8,760	0

BOILER SPECIFICATIONS

Furnace Type: Tangential Firing
Manufacturer: Combustion Engineering
Model & Serial CE-VU40, 21321
Unit Descriptio External Combustion Tangential Fired Boiler
First Service or Last Mod. Date 1976
Maximum Continuous Rating: 371.0 Coal, Natural Gas,
(MMBTU/HR) & Fuel Oil

STACK DATA

Height (ft) 130
Inside Diameter (ft) 8
Exhaust Flow Rate (acfm)
Normal 150,000 Max 174,924
Exhaust Velocity (fps) at MCR 58.00
Calculated or Stack Test (C/ST) ST
Exhaust Temperature (F) 380

Maximum Hourly Fuel Usage (units/hr)		
Fuel Type	Unit	Rate
SubBituminous Coal	ton/hr	17.14
Waste Oil	gal/hr	11
Alcohol	gal/hr	32.0

Exhaust Moisture Content (if modified) (%)
Normal 12 Max 13
Orientation of Release Up
Rainhat or Other Obstruction None

Does the boiler/furnace have control technolog Y

Control Technology and Efficiency (%)

Control Devi	NOx	PM	SOx
Baghouse	0	99.9	0

[redacted]

Miscellaneous		Condensors		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	C002

OPERATING PARAMETERS

	1994 Revised		Potential
Sub Bit Coal Fired (tons) =	124,107	Sub Bit Coal Fired (tons) =	150,171
Avg. Sulfur Content (%) =	0.45	Avg. Sulfur Content (%) =	1
Avg. Ash Content (%) =	7.00	Avg. Ash Content (%) =	7
HHV Coal (Btu/lb) =	11,400	HHV Coal (Btu/lb) =	11,400
Alcohol (gals) =	283,445	Alcohol (gals) =	283,445
Avg. Alcohol Sulfur Content (%) =	0.34	Avg. Alcohol Sulfur Content (%) =	0.34
Avg. Alcohol Ash Content (%) =	0.1	Avg. Alcohol Ash Content (%) =	0.1
HHV Alcohol (Btu/ton) =	2.00E+06	HHV Alcohol (Btu/ton) =	2.00E+06
Waste Oil Fired (gals) =	15,703	Waste Oil Fired (gals) =	100,000
Avg. Sulfur Content (%) =	0.5	Avg. Sulfur Content (%) =	0.5
Avg. Ash Content (%) =	0.65	Avg. Ash Content (%) =	0.65
HHV Oil (Btu/gal) =	149,000	HHV Oil (Btu/gal) =	149,000
Operation Hours =	8,208	Operation Hours =	8,760

EMISSION CALCULATIONS **Unit 4**

Pollutant	Source of Emission Factor/CEM	Units of Emission Factor	Emission Factors: Coal	Alcohol	Waste Oil	Actual Emissions (tpy)	PTE 100% Coal (tpy)	PTE Coal and Alcohol (tpy)	PTE Coal, Alcohol, Waste Oil (tpy)
NOx	AP-42[1]	lb/ton	8.4			521	1,104		
	AP-42[9]	lb/10^3 gal		21		3		1,104	
	AP-42(3)	lb/10^3 gal			19.0	0			1,104
					Total Calculated this sheet:	524			
	CEM(5)	NA	NA	NA	NA	**644.01**		NA	NA
CO	AP-42[1]	lb/ton	0.5			31.0	88.00		
	AP-42 [9]	lb/10^3 gal		5.6		1		88.00	
	AP-42(3)	lb/10^3 gal			5.0	0.04			88.00
					Total Calculated this sheet:	**32**			
NMTOC	AP-42[1]	lb/ton	0.06			3.7	5.30		
	AP-42[9]	lb/10^3 gal		0.4		0.1		5.30	
	AP-42(3)	lb/10^3 gal			1.00	0.0			5.30
					Total Calculated this sheet:	**3.8**			
PM	AP-42[1]	lb/ton	70			4.3	158.00		
	AP-42[9]	lb/10^3 gal		0.600		0.0		158.00	
	AP-42[8]	lb/10^3 gal			41.60	0.0			158.00
					Total Calculated this sheet:	**4.3**			
PM10	AP-42[4]	lb/ton	16.1			0.7	158.00		
	AP-42[9]	lb/10^3 gal		0.60		0.0		158.00	
	AP-42[8]	lb/10^3 gal			33.2	0.0			158.00
					Total Calculated this sheet:	**0.7**			
SOx	AP-42[1]	lb/ton	15.75			977	1,892.00		
	AP-42(2)	lb/10^3 gal		0.03		0		1,892.00	
	AP-42(3)	lb/10^3 gal			73.50	0			1,892.00
					Total Calculated this sheet:	977			
	CEM(5)	NA	NA	NA	NA	**898.30**		NA	NA

Unit 5

TRIGEN-COLORADO ENERGY CORPORATION

Criteria and HAP Emissions from Coal, Alcohol, and Waste Oil

Stack Identification Code : S005	Unit Code: B005

Seasonal Fuel Usage (%)				Normal Operation of Unit			Space Heat (%)
Dec-Feb	Mar-May	Jun-Aug	Sep-Nov	Hours/Day	Days/Week	Hours/year	
25	25	25	25	24	7	8,760	0

BOILER SPECIFICATIONS		STACK DATA	
Furnace Type	Tangential Firing	Height (ft)	200
Manufacturer:	Combustion Engineering	Inside Diameter (ft)	13
Model & Serial	CE-VU40, 27576	Exhaust Flow Rate (acfm)	
Unit Description	External Combustion Tangential Fired Boiler	Normal 290,000 Max	302,630
First Service or Last Mod. Date	1979	Exhaust Velocity (fps) at MCR	38.00
Maximum Continuous Rating: (MMBTU/HR)	652.5 Coal, Natural Gas, & Fuel Oil	Calculated or Stack Test (C/ST)	ST
		Exhaust Temperature (F)	380

Maximum Hourly Fuel Usage (units/hr)		
Fuel Type	Unit	Rate
SubBituminous Coal	ton/hr	36.11
Waste Oil	gal/hr	23
Alcohol	gal/hr	129.4

Exhaust Moisture Content (if modified) (%): Normal 12, Max 13

Orientation of Release: Up

Rainhat or Other Obstruction: None

Does the boiler/furnace have control technolo: Y

Control Technology and Efficiency (%)			
Control Devic	NOx	PM	SOx
Baghouse	0	99.9	0

Miscellaneous		Condensors		Adsorbers		Catalytic/Thermal Oxidation	
2000-400	NONE	2000-401	NONE	2000-402	NONE	2000-403	NONE
Cyclones/Settling Chambers		**Electrostatic Precipitators**		**Wet Collection Systems**		**Baghouses/Fabric Filters**	
2000-404	NONE	2000-405	NONE	2000-406	NONE	2000-407	C003

OPERATING PARAMETERS

1994 Revised		Potential	
Sub Bit Coal Fired (tons) =	234,930	• Sub Bit Coal Fired (tons) =	316,333
Avg. Sulfur Content (%) =	0.45	Avg. Sulfur Content (%) =	1
Avg. Ash Content (%) =	7.00	Avg. Ash Content (%) =	7
HHV Coal (Btu/lb) =	11,400	HHV Coal (Btu/lb) =	11,400
Alcohol (gals) =	1,133,782	Alcohol (gals) =	1,133,782
Avg. Alcohol Sulfur Content (%) =	0.34	Avg. Alcohol Sulfur Content (%) =	0.34
Avg. Alcohol Ash Content (%) =	0.1	Avg. Alcohol Ash Content (%) =	0.1
HHV Alcohol (Btu/ton) =	2,000,000	HHV Alcohol (Btu/ton) =	2,000,000
Waste Oil Fired (gals) =	31,407	Waste Oil Fired (gals) =	200,000
Avg. Sulfur Content (%) =	0.5	Avg. Sulfur Content (%) =	0.5
Avg. Ash Content (%) =	0.65	Avg. Ash Content (%) =	0.65
HHV Oil (Btu/gal) =	149,000	HHV Oil (Btu/gal) =	149,000
Operation Hours =	8,760	Operation Hours =	8,760

EMISSION CALCULATIONS — Unit 5

Pollutant	Source of Emission Factor/CEM	Units of Emission Factor	Emission Factors: Coal	Alcohol	Waste Oil	Actual Emissions (tpy)	PTE 100% Coal (tpy)	PTE Coal and Alcohol (tpy)	PTE Coal, Alcohol, Waste Oil (tpy)
NOx	AP-42[1]	lb/ton	8.4			987	1,993		
	AP-42[9]	lb/10^3 gal		21		11.90		1,993	
	AP-42(3)	lb/10^3 gal			19.0	0.30			1,993
				Total Calculated this sheet:		999			
	CEM(5)	NA	NA	NA	NA	**707.08**		NA	NA
CO	AP-42[1]	lb/ton	0.50			58.73	103.10		
	AP-42 [9]	lb/10^3 gal		3.6		2.04		103.10	
	AP-42(3)	lb/10^3 gal			5.0	0.08			103.10
				Total Calculated this sheet:		**61**			
NMTOC	AP-42[1]	lb/ton	0.06			7.05	9.50		
	AP-42[9]	lb/10^3 gal		0.4		0.23		9.50	
	AP-42(3)	lb/10^3 gal			1.00	0.02			9.50
				Total Calculated this sheet:		**7.3**			
PM	AP-42[1]	lb/ton	70.00			8.22	285.00		
	AP-42[9]	lb/10^3 gal		0.[illegible]00		0.00		285.00	
	AP-42[8]	lb/10^3 gal			41.60	0.00			285.0
				Total Calculated this sheet:		**8.2**			
PM10	AP-42[4]	lb/ton	16.10			1.89	285.00		
	AP-42[9]	lb/10^3 gal		0.60		0.00		285.00	
	AP-42[8]	lb/10^3 gal			33.2	0.00			285.0
				Total Calculated this sheet:		**1.9**			
SOx	AP-42[1]	lb/ton	15.75			1,850	3,416.00		
	AP-42(2)	lb/10^3 gal		0.03		0.02		3,416.00	
	AP-42(3)	lb/10^3 gal			73.50	0.00			3,416.00
				Total Calculated this sheet:		1,850			
	CEM(5)	NA	NA	NA	NA	**1,575.28**		NA	NA

UDS Refinery (previously Colorado Refining Company)

COLORADO REFINING COMPANY
A SUBSIDIARY OF TOTAL PETROLEUM, INC.

5800 BRIGHTON BOULEVARD
COMMERCE CITY, COLORADO 80022

TELEPHONE 303 295-4500

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January 17, 2000

Mr. Long Nguyen
Air Pollution Control Division
Colorado Department of Public Health and Environment
4300 Cherry Creek Drive South
Denver, Colorado 80246-1530

RE: Emission Calculation – PTE for NOx, SOx, PM10

Dear Mr. Nguyen:

Enclosed please find Colorado Refining Company's (CRC) potential to emit (PTE) calculations for the sources that you had requested.

If you require more information or have any questions or comments, please call me at (303) 227-2414.

Sincerely,

Mark Suyama
Environmental Engineer

Enclosure

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AIR POLLUTION CONTROL
STATIONARY SOURCES PROGRAM

CRUDE & VACUUM HEATERS
Potential To Emit

Design Ratings

Crude Heater	88 MMBTU/hr
Vacuum Heater	31 MMBTU/hr

Emission Factors

Crude Heater

NOx	85 lb/MMscf	Vendor
SO_2	120 ppm/H2S	Fuel Gas Maximum
PM10	13.7 lb/MMscf	AP-42 (Table 1.4-3 Small Industrial Boilers - Low NOx Burners)

Vacuum Heater

NOx	0.075 lb/MMBTU	Vendor
SO_2	120 ppm/H2S	Fuel Gas Maximum
PM10	13.7 lb/MMscf	AP-42 (Table 1.4-3 Small Industrial Boilers - Low NOx Burners)

Emission Calculations

Crude Heater

NOx: (88 MMBTU/hr)(8760 hr/yr)(10^6 BTU/MMBTU)(Scf/1000BTU)(MMscf/106 Scf)(85 lb/MMscf)(Ton/2000 lb) = 32.8 TPY

SO_2: (88 MMBTU/hr)(MMscf/450 MMBTU)(120 ft3/MMscf)(lb mol/379 ft3)(64 lb SO_2/lb mol)(8760 hr/yr)(Ton/2000 lb) = 17.3 TPY

PM10: (88 MMBTU/hr)(8760 hr/yr)(10^6 BTU/MMBTU)(Scf/1000 BTU)(MMscf/106 Scf)(13.7 lb/MMscf)(Ton/2000lb) = 5.2 TPY

Vacuum Heater

NOx: (31 MMBTU/hr)(0.075 lb/MMBTU)(Ton/2000 lb)(8760 hr/yr) = 10.1 TPY

SO_2: (31 MMBTU/hr)(MMscf/450 MMBTU)(120 ft3/MMscf)(lb mol/379 ft3)(64 lb SO_2/lb mol)(8760 hr/yr)(Ton/2000 lb) = 6.1 TPY

PM10: (31 MMBTU/hr)(8760 hr/yr)(10^6 BTU/MMBTU)(Scf/1000 BTU)(MMscf/106 Scf)(13.7 lb/MMscf)(Ton/2000lb) = 1.8 TPY

$NO_x \Rightarrow 42.9$ ✓

$SO_2 \Rightarrow 17.3 + 6.1 \Rightarrow 23.4$ ✓

$PM_{10} \Rightarrow 7.0$ ✓

BLACK OIL HEATER
Potential To Emit

Design Ratings

BLACK OIL HEATER	8.1 MMBTU/hr

Emission Factors
Black Oil Heater

NOx	100 lb MMscf	AP-42 (Table 1.4-2)
SO2	120 ppm/H2S	Fuel Gas Maximum
PM10	12 lb/MMscf	AP-42 (Table 1.4-1)

Emission Calculations
Black Oil Heater
NOx: (8.1 MMBTU/hr)(0.11 lb/MMBTU)(Ton/2000 lb)(8760 hr/yr) = 3.8 TPY
SO2: (8.1 MMBTU/hr)(MMscf/450 MMBTU)(120 ft3/MMscf)(lb mol/379 ft3)(64 lb SO2/lb mol)(8760 hr/yr)(Ton/2000 lb) = 1.6 TPY
PM10: (8.1 MMBTU/hr)(0.005 lb/MMscf)(Ton/2000lb)(8760 hr/yr) = 0.2 TPY

REFORMER HEATERS
Potential To Emit

Design Ratings

Reformer Heaters 161 MMBTU/hr

Emission Factors

Reformer Heaters

NOx	0.075 lb/MMBTU	Source Test Data
SO2	120 ppm/H2S	Fuel Gas Maximum
PM10	13.7 lb/MMscf	AP-42 (Table 1.4-3 Small Industrial Boilers - Low NOx Burners (6.2 + 7.5))

Emission Calculations

Reformer Heaters

NOx: (161MMBTU/hr)(0.075 lb/MMBTU)(Ton/2000 lb)(8760 hr/yr) = 52.8 TPY

SO2: (161MMBTU/hr)(MMscf/450 MMBTU)(120 ft3/MMscf)(lbmol/379 ft3)(64 lb SO2/lbmol)(8760 hr/yr)(Ton/2000 lb) = 31.8 TPY

PM10: (161 MMBTU/hr)(8760 hr/yr)(10^6 BTU/MMBTU)(Scf/1000 BTU)(MMscf/10^6 Scf)(13.7 lb/MMscf)(Ton/2000lb) = 9.7 TPY

UTILITIES - BOILERS
Potential To Emit

Design Ratings

Utilities	225 MMBTU/hr

Emission Factors
Utilities

NOx	140 lb/10^6 ft3	AP-42 (Table 1.4-2 Small Industrial Boilers)
SO2	120 ppm/H2S	Fuel Gas Maximum
PM10	13.7 lb/MMscf	AP-42 (Table 1.4-3 Small Industrial Boilers - Low NOx Burners (6.2 + 7.5))

Emission Calculations
Utilities
NOx: (225 MMBTU/hr)(0.075 lb/MMBTU)(Ton/2000 lb)(8760 hr/yr) = 73.9 TPY
SO2: (225MMBTU/hr)(MMscf/1000 MMBTU)(120 ft3/MMscf)(lbmol/379 ft3)(64 lb SO2/lbmol)(8760 hr/yr)(Ton/2000 lb) = 19.9 TP'
PM10: (225 MMBTU/hr)(8760 hr/yr)(10^6 BTU/MMBTU)(Scf/1000 BTU)(MMscf/10^6 Scf)(13.7 lb/MMscf)(Ton/2000lb) = 13.5 TPY

REFINERY FLARE
Potential To Emit

Design Ratings

Refinery Flare 131,282 MMBTU/yr
(Maximum Refinery Throughput ~35,000 bbl)

Emission Factors

Refinery Flare

NOx	0.068 lb/MMBTU	AP-42 (Table 13.5-1 Emission Factors for Flare Operations)
SO2	26.9 lb/10^3 bbl	
PM10	137 lb/MMBTU	AP-42 (Table 13.5-1 Emission Factors for Flare Operations)

Emission Calculations

Refinery Flare
NOx: (133,282 MMBTU/yr)(0.068 lb/MMBTU)(Ton/2000 lb) = 4.6 TPY
SO2: (26.9 lb SO2/1000 bbl)(35,000 bbl/day)(365 day/yr)(Ton/2000 lb) = 172 TPY
PM10: (137ug/L)(g/10^6 ug)(lb/454 g)(28.32 g/ft^3)(212.5 $MMft^3$)(Ton/2000 lb) = 0.9 TPY

FLUID CATALYTIC CRACKING UNIT
Potential To Emit

Design Ratings

FCCU Preheater 75 MMBTU/hr
(Maximum Refinery Throughput ~35,000 bbl)

Emission Factors

FCCU PH		
NOx	140 lb/MMscf	AP-42 (Table 1.4-2 Emission Factors for Sox, Nox, CO from Natural Gas Combustion)
SO2	120 PPM	Max. H2S in Fuel Gas
PM10	13.7 lb/MMscf	AP-42 (Table 1.4-2 Emission Factors for Sox, Nox, CO from Natural Gas Combustion)

Emission Calculations

FCCU PH
NOx: (75 MMBTU/hr)(MMscf/450 MMBTU)(8760 hr/yr)(140 lb/MMscf)(Ton/2000 lb) = 102.2 TPY
SO2: (1460 MMscf/yr)(120 ft3 H2S/MMscf)(34 lb H2S/lb mol)(lb mol/379.5 ft3)(64 lb SO2/34lb H2S)(Ton/2000 lb) = 14.77 TPY
PM10: (75 MMBTU/hr)(MMscf/450 MMBTU)(8760 hr/yr)(13.7 lb/MMscf)(Ton/2000 lb) = 10.0 TPY

FLUID CATALYTIC CRACKING UNIT
Potential To Emit

Design Ratings

	FCCU REGEN - Coke Make	5788.7 lbs/hr
		50,709,012 lbs/yr

Emission Factors
FCCU REGEN

NOx	2.41 lbs/1000 lbs Coke Make
SO2	17.35 lb/1000 lbs Coke Make
PM10	7.88 lbs/1000 lbs Coke Make

Emission Calculations
FCCU REGEN
NOx: (50,709,012 lbs/yr)(2.41 lbs/1000 lb)(Ton/2000 lb) = 61 TPY
SOx: (50,709,012 lbs/yr)(17.35 lbs/1000 lb)(Ton/2000 lb) = 440 TPY
PM10: (50,709,012 lbs/yr)(7.88 lbs/1000 lb)(Ton/2000 lb) = 200 TPY

SULFUR RECOVERY UNIT INCINERATOR
Potential To Emit

Design Ratings

	Sulfur Recovery Unit	6 Long Tons per Day
		21,000 MMBTU/yr Consumption Limit
		2.4 MMBTU/yr Maximum Gas Input to the Incinerator

Emission Factors
Sulfur Recovery Unit

NOx	100 lb/MMscf	AP-42 (Table 1.4-2 Commercial Boilers)
SO2	120 ppm/H2S	Fuel Gas Maximum
PM10	12.0 lb/MMscf	AP-42 (Table 1.4-1 Commercial Boilers (4.5 + 7.5))

Emission Calculations
Sulfur Recovery Unit

The SO_2 PTE is a combination of the SO_2 created by converting the tail gas H_2S to SO_2 in the incinerator and the SO_2 created by combustion of the incinerator pilot feed.

Tail Gas
The maximum amount of sulfur leaving the Claus unit is designed to be constant

The amount of sulfur leaving the Claus unit is designed to be 0.42 long tons per day

6 long tons/day x (1-0.93) = 0.42 long tons/day S

Using a conservative assumption of 100% conversion of H_2S to SO_2, this leads to:

0.42 long tons/day x 5 short tons/4.464 long tons x 2000 lb/ton x lbmole/32 lb S x lbmole H_2S/lbmole S = 29.4 lbmole H_2S/day

29.4 lbmole H_2S/day x 365 days/yr x 64 lb SO_2/lbmole x lbmole SO_2/lbmole H_2S x ton/2000 lb = **343.4 ton SO_2/yr** -- out of the SRU tail gas incinerator due to tail gas

Pilot Feed
Some SO_2 will also be formed from combustion of the pilot gas fed to the SRU tail gas incinerator.

Btu Rating of SRU tail gas incinerator = 1.95 mmbtu/hr
Refinery gas heat content = 400 Btu/scf
Potential fuel feed to the SRU incinerator:
120 ppmv H_2S in the pilot fuel at a maximum

1.95 mmbtu/hr x mmcf/400 mmbtu x 8760 hr/yr = 42.71 mmcf/yr

This conservatively assumes that the entire feed to the SRU incinerator is fuel gas rather than a mix of fuel gas and tail gas.

42.71 mmcf/yr pilot fuel x 120 ft3 H_2S/mmcf x lbmole H_2S/379 ft3 x lbmole SO_2/lbmole H_2S x 64 lb SO_2/lbmole x ton/2000 lb = **0.43 ton SO_2/yr** -- From combustion of pilot fuel

Total SO_2: 343.4 + 0.43 = **343.83 ton SO_2/yr**

LPG Loading/Unloading Flare
Potential To Emit

Design Ratings

Loading of LPG 350,000,000 gal/yr
Heat Input = 404,400 MMBTU/yr

Emission Factors

LPG Loading/Unloading Flare

NOx	0.068 lb/MMBTU	AP-42 (Table 13.5-1 Emission Factors for Flare Operations)

Emission Calculations

LPG Loading/Unloading Flare
NOx: (404,400 MMBTU/yr)(0.068 lb/MMBTU)(Ton/2000 lb) = 13.75 TPY

Product Dock Loading
Potential To Emit

Design Ratings

Loading of Product 578,160,000 gal/yr
Capture efficiency = 95%

Emission Factors
Product Dock Loading
NOx 0.068 lb/MMBTU AP-42 (Table 13.5-1 Emission Factors for Flare Operations)

Emission Calculations
Product Dock Loading
L_L: (8.15 lb/1000 gal)(578,160,000 gal)(Ton/2000 lb) = 2356 TPY
Quantity Uncaptured: (2356 tpy)(0.01%) = 23.6 TPY
Quantity Flared: (2356-23.6)(0.95) = 2216
Heat Content Flared: (2216 TPY)(2000 lb/Ton)(19000 BTU/lb) = 84,208 MMBTU/yr
NOx: (84,208 MMBTU/yr)(0.068 lb/MMBTU)(Ton/2000 lb) = 2.9 TPY
PM: de minimus
SOx: de minimus

Appendix E.5 40CFR Part 60 NSPS Subpart D

TABLE 2 TO SUBPART CE—EMISSIONS LIMITS FOR SMALL HMIWI WHICH MEET THE CRITERIA UNDER §60.33E(B)

Pollutant	Units (7 percent oxygen, dry basis)	HMIWI emission limits
Particulate matter	Milligrams per dry standard cubic meter (grains per dry standard cubic foot).	197 (0.086).
Carbon monoxide	Parts per million by volume	40.
Dioxins/furans	nanograms per dry standard cubic meter total dioxins/furans (grains per billion dry standard cubic feet) or nanograms per dry standard cubic meter TEQ (grains per billion dry standard cubic feet).	800 (350) or 15 (6.6).
Hydrogen chloride	Parts per million by volume	3100.
Sulfur dioxide	Parts per million by volume	55.
Nitrogen oxides	Parts per million by volume	250.
Lead	Milligrams per dry standard cubic meter (grains per thousand dry standard cubic feet).	10 (4.4).
Cadmium	Milligrams per dry standard cubic meter (grains per thousand dry standard cubic feet).	4 (1.7).
Mercury	Milligrams per dry standard cubic meter (grains per thousands dry standard cubic feet).	7.5 (3.3).

Subpart D—Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971

§60.40 Applicability and designation of affected facility.

(a) The affected facilities to which the provisions of this subpart apply are:

(1) Each fossil-fuel-fired steam generating unit of more than 73 megawatts heat input rate (250 million Btu per hour).

(2) Each fossil-fuel and wood-residue-fired steam generating unit capable of firing fossil fuel at a heat input rate of more than 73 megawatts (250 million Btu per hour).

(b) Any change to an existing fossil-fuel-fired steam generating unit to accommodate the use of combustible materials, other than fossil fuels as defined in this subpart, shall not bring that unit under the applicability of this subpart.

(c) Except as provided in paragraph (d) of this section, any facility under paragraph (a) of this section that commenced construction or modification after August 17, 1971, is subject to the requirements of this subpart.

(d) The requirements of §§60.44 (a)(4), (a)(5), (b) and (d), and 60.45(f)(4)(vi) are applicable to lignite-fired steam generating units that commenced construction or modification after December 22, 1976.

(e) Any facility covered under subpart Da is not covered under this subpart.

[42 FR 37936, July 25, 1977, as amended at 43 FR 9278, Mar. 7, 1978; 44 FR 33612, June 17, 1979]

§60.41 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, and in subpart A of this part.

(a) *Fossil-fuel fired steam generating unit* means a furnace or boiler used in the process of burning fossil fuel for the purpose of producing steam by heat transfer.

(b) *Fossil fuel* means natural gas, petroleum, coal, and any form of solid, liquid, or gaseous fuel derived from such materials for the purpose of creating useful heat.

(c) *Coal refuse* means waste-products of coal mining, cleaning, and coal preparation operations (e.g. culm, gob, etc.) containing coal, matrix material, clay, and other organic and inorganic material.

(d) *Fossil fuel and wood residue-fired steam generating unit* means a furnace or boiler used in the process of burning fossil fuel and wood residue for the purpose of producing steam by heat transfer.

(e) *Wood residue* means bark, sawdust, slabs, chips, shavings, mill trim, and other wood products derived from wood processing and forest management operations.

(f) *Coal* means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society and Testing and Materials, Designation D388–77 (incorporated by reference—see §60.17).

[39 FR 20791, June 14, 1974, as amended at 40 FR 2803, Jan. 16, 1975; 41 FR 51398, Nov. 22, 1976; 43 FR 9278, Mar. 7, 1978; 48 FR 3736, Jan. 27, 1983]

§ 60.42 Standard for particulate matter.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which:

(1) Contain particulate matter in excess of 43 nanograms per joule heat input (0.10 lb per million Btu) derived from fossil fuel or fossil fuel and wood residue.

(2) Exhibit greater than 20 percent opacity except for one six-minute period per hour of not more than 27 percent opacity.

(b)(1) On or after December 28, 1979, no owner or operator shall cause to be discharged into the atmosphere from the Southwestern Public Service Company's Harrington Station #1, in Amarillo, TX, any gases which exhibit greater than 35% opacity, except that a maximum or 42% opacity shall be permitted for not more than 6 minutes in any hour.

(2) Interstate Power Company shall not cause to be discharged into the atmosphere from its Lansing Station Unit No. 4 in Lansing, IA, any gases which exhibit greater than 32% opacity, except that a maximum of 39% opacity shall be permitted for not more than six minutes in any hour.

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 42 FR 61537, Dec. 5, 1977; 44 FR 76787, Dec. 28, 1979; 45 FR 36077, May 29, 1980; 45 FR 47146, July 14, 1980; 46 FR 57498, Nov. 24, 1981; 61 FR 49976, Sept. 24, 1996]

§ 60.43 Standard for sulfur dioxide.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain sulfur dioxide in excess of:

(1) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from liquid fossil fuel or liquid fossil fuel and wood residue.

(2) 520 nanograms per joule heat input (1.2 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue, except as provided in paragraph (e) of this section.

(b) When different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) shall be determined by proration using the following formula:

$$PS_{SO2}=[y(340)+z(520)]/(y+z)$$

where:

PS_{SO2} is the prorated standard for sulfur dioxide when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired,

y is the percentage of total heat input derived from liquid fossil fuel, and

z is the percentage of total heat input derived from solid fossil fuel.

(c) Compliance shall be based on the total heat input from all fossil fuels burned, including gaseous fuels.

(d) [Reserved]

(e) Units 1 and 2 (as defined in appendix G) at the Newton Power Station owned or operated by the Central Illinois Public Service Company will be in compliance with paragraph (a)(2) of this section if Unit 1 and Unit 2 individually comply with paragraph (a)(2) of this section or if the combined emission rate from Units 1 and 2 does not exceed 470 nanograms per joule (1.1 lb per million Btu) combined heat input to Units 1 and 2.

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 52 FR 28954, Aug. 4, 1987]

§ 60.44 Standard for nitrogen oxides.

(a) On and after the date on which the performance test required to be conducted by § 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain nitrogen oxides, expressed as NO_2 in excess of:

(1) 86 nanograms per joule heat input (0.20 lb per million Btu) derived from gaseous fossil fuel.

(2) 129 nanograms per joule heat input (0.30 lb per million Btu) derived from liquid fossil fuel, liquid fossil fuel and wood residue, or gaseous fossil fuel and wood residue.

(3) 300 nanograms per joule heat input (0.70 lb per million Btu) derived from solid fossil fuel or solid fossil fuel and wood residue (except lignite or a solid fossil fuel containing 25 percent, by weight, or more of coal refuse).

(4) 260 nanograms per joule heat input (0.60 lb per million Btu) derived from lignite or lignite and wood residue (except as provided under paragraph (a)(5) of this section).

(5) 340 nanograms per joule heat input (0.80 lb per million Btu) derived from lignite which is mined in North Dakota, South Dakota, or Montana and which is burned in a cyclone-fired unit.

(b) Except as provided under paragraphs (c) and (d) of this section, when different fossil fuels are burned simultaneously in any combination, the applicable standard (in ng/J) is determined by proration using the following formula:

$$PS_{NO_x} = \frac{w(260) + x(86) + y(130) + z(300)}{w + x + y + z}$$

where:

PS_{NOx}=is the prorated standard for nitrogen oxides when burning different fuels simultaneously, in nanograms per joule heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w= is the percentage of total heat input derived from lignite;

x= is the percentage of total heat input derived from gaseous fossil fuel;

y= is the percentage of total heat input derived from liquid fossil fuel; and

z= is the percentage of total heat input derived from solid fossil fuel (except lignite).

(c) When a fossil fuel containing at least 25 percent, by weight, of coal refuse is burned in combination with gaseous, liquid, or other solid fossil fuel or wood residue, the standard for nitrogen oxides does not apply.

(d) Cyclone-fired units which burn fuels containing at least 25 percent of lignite that is mined in North Dakota, South Dakota, or Montana remain subject to paragraph (a)(5) of this section regardless of the types of fuel combusted in combination with that lignite.

[39 FR 20792, June 14, 1974, as amended at 41 FR 51398, Nov. 22, 1976; 43 FR 9278, Mar. 7, 1978; 51 FR 42797, Nov. 25, 1986]

§ 60.45 Emission and fuel monitoring.

(a) Each owner or operator shall install, calibrate, maintain, and operate continuous monitoring systems for measuring the opacity of emissions, sulfur dioxide emissions, nitrogen oxides emissions, and either oxygen or carbon dioxide except as provided in paragraph (b) of this section.

(b) Certain of the continuous monitoring system requirements under paragraph (a) of this section do not apply to owners or operators under the following conditions:

(1) For a fossil fuel-fired steam generator that burns only gaseous fossil fuel, continuous monitoring systems for measuring the opacity of emissions and sulfur dioxide emissions are not required.

(2) For a fossil fuel-fired steam generator that does not use a flue gas desulfurization device, a continuous monitoring system for measuring sulfur dioxide emissions is not required if the owner or operator monitors sulfur dioxide emissions by fuel sampling and analysis under paragraph (d) of this section.

(3) Notwithstanding § 60.13(b), installation of a continuous monitoring system for nitrogen oxides may be delayed until after the initial performance tests under § 60.8 have been conducted. If the owner or operator demonstrates during the performance test that emissions of nitrogen oxides are less than 70 percent of the applicable standards in § 60.44, a continuous monitoring system for measuring nitrogen oxides emissions is not required. If the initial performance test results show that nitrogen oxide emissions are greater than 70 percent of the applicable standard, the owner or operator shall install a continuous monitoring system for nitrogen oxides within one year after the date of the initial performance tests under § 60.8 and comply with all other

applicable monitoring requirements under this part.

(4) If an owner or operator does not install any continuous monitoring systems for sulfur oxides and nitrogen oxides, as provided under paragraphs (b)(1) and (b)(3) or paragraphs (b)(2) and (b)(3) of this section a continuous monitoring system for measuring either oxygen or carbon dioxide is not required.

(c) For performance evaluations under § 60.13(c) and calibration checks under § 60.13(d), the following procedures shall be used:

(1) Methods 6, 7, and 3B, as applicable, shall be used for the performance evaluations of sulfur dioxide and nitrogen oxides continuous monitoring systems. Acceptable alternative methods for Methods 6, 7, and 3B are given in § 60.46(d).

(2) Sulfur dioxide or nitric oxide, as applicable, shall be used for preparing calibration gas mixtures under Performance Specification 2 of appendix B to this part.

(3) For affected facilities burning fossil fuel(s), the span value for a continuous monitoring system measuring the opacity of emissions shall be 80, 90, or 100 percent and for a continuous monitoring system measuring sulfur oxides or nitrogen oxides the span value shall be determined as follows:

[In parts per million]

Fossil fuel	Span value for sulfur dioxide	Span value for nitrogen oxides
Gas	([1])	500
Liquid	1,000	500
Solid	1,500	1000
Combinations	$1{,}000y+1{,}500z$	$500(x+y)+1{,}000z$

[1] Not applicable.

where:

x=the fraction of total heat input derived from gaseous fossil fuel, and

y=the fraction of total heat input derived from liquid fossil fuel, and

z=the fraction of total heat input derived from solid fossil fuel.

(4) All span values computed under paragraph (c)(3) of this section for burning combinations of fossil fuels shall be rounded to the nearest 500 ppm.

(5) For a fossil fuel-fired steam generator that simultaneously burns fossil fuel and nonfossil fuel, the span value of all continuous monitoring systems shall be subject to the Administrator's approval.

(d) [Reserved]

(e) For any continuous monitoring system installed under paragraph (a) of this section, the following conversion procedures shall be used to convert the continuous monitoring data into units of the applicable standards (ng/J, lb/million Btu):

(1) When a continuous monitoring system for measuring oxygen is selected, the measurement of the pollutant concentration and oxygen concentration shall each be on a consistent basis (wet or dry). Alternative procedures approved by the Administrator shall be used when measurements are on a wet basis. When measurements are on a dry basis, the following conversion procedure shall be used:

$E=CF[20.9/(20.9-\text{percent } O_2)]$

where:

E, C, F, and $\%O_2$ are determined under paragraph (f) of this section.

(2) When a continuous monitoring system for measuring carbon dioxide is selected, the measurement of the pollutant concentration and carbon dioxide concentration shall each be on a consistent basis (wet or dry) and the following conversion procedure shall be used:

$E=CF_c\,[100/\text{percent } CO_2]$

where:

E, C, F_c and $\%CO_2$ are determined under paragraph (f) of this section.

(f) The values used in the equations under paragraphs (e) (1) and (2) of this section are derived as follows:

(1) *E*=pollutant emissions, ng/J (lb/million Btu).

(2) *C*=pollutant concentration, ng/dscm (lb/dscf), determined by multiplying the average concentration (ppm) for each one-hour period by 4.15×10^{4} M ng/dscm per ppm (2.59×10^{-9} M lb/dscf per ppm) where *M*=pollutant molecular weight, g/g-mole (lb/lb-mole). *M*=64.07 for sulfur dioxide and 46.01 for nitrogen oxides.

(3) $\%O_2$, $\%CO_2$=oxygen or carbon dioxide volume (expressed as percent), determined with equipment specified under paragraph (a) of this section.

(4) F, F_c=a factor representing a ratio of the volume of dry flue gases generated to the calorific value of the fuel

combusted (F), and a factor representing a ratio of the volume of carbon dioxide generated to the calorific value of the fuel combusted (F_c), respectively. Values of F and F_c are given as follows:

(i) For anthracite coal as classified according to ASTM D388-77 (incorporated by reference—see §60.17), $F=2,723 \times 10^{-17}$ dscm/J (10,140 dscf/million Btu and $F_c=0.532 \times 10^{-17}$ scm CO_2/J (1,980 scf CO_2/million Btu).

(ii) For subbituminous and bituminous coal as classified according to ASTM D388-77 (incorporated by reference—see §60.17), $F=2.637 \times 10^{-7}$ dscm/J (9,820 dscf/million Btu) and $F_c=0.486 \times 10^{-7}$ scm CO_2/J (1,810 scf CO_2/ million Btu).

(iii) For liquid fossil fuels including crude, residual, and distillate oils, $F=2.476 \times 10^{-7}$ dscm/J (9,220 dscf/million Btu) and $F_c=0.384 \times 10^{-7}$ scm CO_2/J (1,430 scf CO_2/million Btu).

(iv) For gaseous fossil fuels, $F=2.347 \times 10^{-7}$ dscm/J (8,740 dscf/million Btu). For natural gas, propane, and butane fuels, $F_c=0.279 \times 10^{-7}$ scm CO_2/J (1,040 scf CO_2/million Btu) for natural gas, 0.322×10^{-7} scm CO_2/J (1,200 scf CO_2/ million Btu) for propane, and 0.338×10^{-7} scm CO_2/J (1,260 scf CO_2/million Btu) for butane.

(v) For bark $F=2.589 \times 10^{-7}$ dscm/J (9,640 dscf/million Btu) and $F_c=0.500 \times 10^{-7}$ scm CO_2/J (1,840 scf CO_2/ million Btu). For wood residue other than bark $F=2.492 \times 10^{-7}$ dscm/J (9,280 dscf/million Btu) and $F_c=0.494 \times 10^{-7}$ scm CO_2/J (1,860 scf CO_2/ million Btu).

(vi) For lignite coal as classified according to ASTM D388-77 (incorporated by reference—see §60.17), $F=2.659 \times 10^{-7}$ dscm/J (9,900 dscf/million Btu) and $F_c=0.516 \times 10^{-7}$ scm CO_2/J (1,920 scf CO_2/ million Btu).

(5) The owner or operator may use the following equation to determine an *F* factor (dscm/J or dscf/million Btu) on a dry basis (if it is desired to calculate *F* on a wet basis, consult the Administrator) or F_c factor (scm CO_2/J, or scf CO_2/million Btu) on either basis in lieu of the *F* or F_c factors specified in paragraph (f)(4) of this section:

$$F = 10^{-6}\frac{[227.2\,(\text{pct. H}) + 95.5\,(\text{pct. C}) + 35.6\,(\text{pct. S}) + 8.7\,(\text{pct. N}) - 28.7\,(\text{pct. O})]}{\text{GCV}}$$

$$F_c = \frac{2.0 \times 10^{-5}\,(\text{pct. C})}{\text{GCV (SI units)}}$$

$$F = \frac{10^{6}[3.64(\%H) + 1.53(\%C) + 0.57(\%S) + 0.14(\%N) - 0.46(\%O)]}{GCV\,(\text{English units})}$$

$$F_c = \frac{20.0\,(\%C)}{GCV\,(\text{SI units})}$$

$$F_c = \frac{321 \times 10^{3}(\%C)}{GCV\,(\text{English units})}$$

(i) H, C, S, N, and O are content by weight of hydrogen, carbon, sulfur, nitrogen, and oxygen (expressed as percent), respectively, as determined on the same basis as GCV by ultimate analysis of the fuel fired, using ASTM method D3178-74 or D3176 (solid fuels) or computed from results using ASTM method D1137-53(75), D1945-64(76), or D1946-77 (gaseous fuels) as applicable. (These five methods are incorporated by reference—see §60.17.)

(ii) GVC is the gross calorific value (kJ/kg, Btu/lb) of the fuel combusted determined by the ASTM test methods D2015-77 for solid fuels and D1826-77 for gaseous fuels as applicable. (These two methods are incorporated by reference—see §60.17.)

(iii) For affected facilities which fire both fossil fuels and nonfossil fuels, the F or F_c value shall be subject to the Administrator's approval.

(6) For affected facilities firing combinations of fossil fuels or fossil fuels and wood residue, the F or F_c factors determined by paragraphs (f)(4) or (f)(5) of this section shall be prorated in accordance with the applicable formula as follows:

$$F = \sum_{i=1}^{n} X_i F_i \text{ or } F_c = \sum_{i=1}^{n} X_i (F_c)_i$$

where:

X_i=the fraction of total heat input derived from each type of fuel (e.g. natural gas, bituminous coal, wood residue, etc.)

F_i or $(F_c)_i$=the applicable F or F_c factor for each fuel type determined in accordance with paragraphs (f)(4) and (f)(5) of this section.

n=the number of fuels being burned in combination.

(g) Excess emission and monitoring system performance reports shall be submitted to the Administrator for every calendar quarter. All quarterly reports shall be postmarked by the 30th day following the end of each calendar quarter. Each excess emission and MSP report shall include the information required in § 60.7(c). Periods of excess emissions and monitoring systems (MS) downtime that shall be reported are defined as follows:

(1) *Opacity*. Excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 20 percent opacity, except that one six-minute average per hour of up to 27 percent opacity need not be reported.

(i) For sources subject to the opacity standard of § 60.42(b)(1), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 35 percent opacity, except that one six-minute average per hour of up to 42 percent opacity need not be reported.

(ii) For sources subject to the opacity standard of § 60.42(b)(2), excess emissions are defined as any six-minute period during which the average opacity of emissions exceeds 32 percent opacity, except that one six-minute average per hour of up to 39 percent opacity need not be reported.

(2) *Sulfur dioxide*. Excess emissions for affected facilities are defined as:

(i) Any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) of sulfur dioxide as measured by a continuous monitoring system exceed the applicable standard under § 60.43.

(3) *Nitrogen oxides*. Excess emissions for affected facilities using a continuous monitoring system for measuring nitrogen oxides are defined as any three-hour period during which the average emissions (arithmetic average of three contiguous one-hour periods) exceed the applicable standards under § 60.44.

[40 FR 46256, Oct. 6, 1975]

EDITORIAL NOTE: For FEDERAL REGISTER citations affecting § 60.45, see the List of CFR Sections Affected in the Finding Aids section of this volume.

§ 60.46 Test methods and procedures.

(a) In conducting the performance tests required in § 60.8, the owner or operator shall use as reference methods and procedures the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in § 60.8(b). Acceptable alternative methods and procedures are given in paragraph (d) of this section.

(b) The owner or operator shall determine compliance with the particulate matter, SO_2, and NO_x standards in §§ 60.42, 60.43, and 60.44 as follows:

(1) The emission rate (E) of particulate matter, SO_2, or NO_x shall be computed for each run using the following equation:

$E = C\ F_d\ (20.9)/(20.9 - \%\ O_2)$

E = emission rate of pollutant, ng/J (lb/million Btu).

C = concentration of pollutant, ng/dscm (lb/dscf).

$\%O_2$ = oxygen concentration, percent dry basis.

F_d = factor as determined from Method 19.

(2) Method 5 shall be used to determine the particular matter concentration (C) at affected facilities without wet flue-gas-desulfurization (FGD) systems and Method 5B shall be used to determine the particulate matter concentration (C) after FGD systems.

(i) The sampling time and sample volume for each run shall be at least 60 minutes and 0.85 dscm (30 dscf). The probe and filter holder heating systems in the sampling train may be set to provide a gas temperature no greater than 160±14 °C (320±25 °F).

(ii) The emission rate correction factor, integrated or grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be obtained simultaneously with, and at the same traverse points as, the particulate sample. If the grab sampling procedure is used, the O_2 concentration for the run shall be the arithmetic mean of all the individual O_2 sample concentrations at each traverse point.

(iii) If the particulate run has more than 12 traverse points, the O_2 traverse points may be reduced to 12 provided that Method 1 is used to locate the 12 O_2 traverse points.

(3) Method 9 and the procedures in § 60.11 shall be used to determine opacity.

(4) Method 6 shall be used to determine the SO_2 concentration.

(i) The sampling site shall be the same as that selected for the particulate sample. The sampling location in the duct shall be at the centroid of the cross section or at a point no closer to the walls than 1 m (3.28 ft). The sampling time and sample volume for each sample run shall be at least 20 minutes and 0.020 dscm (0.71 dscf). Two samples shall be taken during a 1-hour period, with each sample taken within a 30-minute interval.

(ii) The emission rate correction factor, integrated sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The O_2 sample shall be taken simultaneously with, and at the same point as, the SO_2 sample. The SO_2 emission rate shall be computed for each pair of SO_2 and O_2 samples. The SO_2 emission rate (E) for each run shall be the arithmetic mean of the results of the two pairs of samples.

(5) Method 7 shall be used to determine the NO_x concentration.

(i) The sampling site and location shall be the same as for the SO_2 sample. Each run shall consist of four grab samples, with each sample taken at about 15-minute intervals.

(ii) For each NO_x sample, the emission rate correction factor, grab sampling and analysis procedure of Method 3B shall be used to determine the O_2 concentration (%O_2). The sample shall be taken simultaneously with, and at the same point as, the NO_x sample.

(iii) The NO_x emission rate shall be computed for each pair of NO_x and O_2 samples. The NO_x emission rate (E) for each run shall be the arithmetic mean of the results of the four pairs of samples.

(c) When combinations of fossil fuels or fossil fuel and wood residue are fired, the owner or operator (in order to compute the prorated standard as shown in §§ 60.43(b) and 60.44(b)) shall determine the percentage (w, x, y, or z) of the total heat input derived from each type of fuel as follows:

(1) The heat input rate of each fuel shall be determined by multiplying the gross calorific value of each fuel fired by the rate of each fuel burned.

(2) ASTM Methods D 2015-77 (solid fuels), D 240-76 (liquid fuels), or D 1826-77 (gaseous fuels) (incorporated by reference—see § 60.17) shall be used to determine the gross calorific values of the fuels. The method used to determine the calorific value of wood residue must be approved by the Administrator.

(3) Suitable methods shall be used to determine the rate of each fuel burned during each test period, and a material balance over the steam generating system shall be used to confirm the rate.

(d) The owner or operator may use the following as alternatives to the reference methods and procedures in this section or in other sections as specified:

(1) The emission rate (E) of particulate matter, SO_2 and NO_x may be determined by using the F_c factor, provided that the following procedure is used:

(i) The emission rate (E) shall be computed using the following equation:

$$E = C\ F_c\ (100/\%CO_2)$$

where:

E=emission rate of pollutant, ng/J (lb/million Btu).

C=concentration of pollutant, ng/dscm (lb/dscf).

$\%CO_2$=carbon dioxide concentration, percent dry basis.
F_c=factor as determined in appropriate sections of Method 19.

(ii) If and only if the average F_c factor in Method 19 is used to calculate E and either E is from 0.97 to 1.00 of the emission standard or the relative accuracy of a continuous emission monitoring system is from 17 to 20 percent, then three runs of Method 3B shall be used to determine the O_2 and CO_2 concentration according to the procedures in paragraph (b) (2)(ii), (4)(ii), or (5)(ii) of this section. Then if F_o (average of three runs), as calculated from the equation in Method 3B, is more than ±3 percent than the average F_o value, as determined from the average values of F_d and F_c in Method 19, i.e., F_{oa}=0.209 (F_{da}/F_{ca}), then the following procedure shall be followed:

(A) When F_o is less than 0.97 F_{oa}, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the emission standard.

(B) When F_o is less than 0.97 F_{oa} and when the average difference ($\bar{d}$) between the continuous monitor minus the reference methods is negative, then E shall be increased by that proportion under 0.97 F_{oa}, e.g., if F_o is 0.95 F_{oa}, E shall be increased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(C) When F_o is greater than 1.03 F_{oa} and when the average difference $\bar{d}$ is positive, then E shall be decreased by that proportion over 1.03 F_{oa}, e.g., if F_o is 1.05 F_{oa}, E shall be decreased by 2 percent. This recalculated value shall be used to determine compliance with the relative accuracy specification.

(2) For Method 5 or 5B, Method 17 may be used at facilities with or without wet FGD systems if the stack gas temperature at the sampling location does not exceed an average temperature of 160 °C (320 °F). The procedures of sections 2.1 and 2.3 of Method 5B may be used with Method 17 only if it is used after wet FGD systems. Method 17 shall not be used after wet FGD systems if the effluent gas is saturated or laden with water droplets.

(3) Particulate matter and SO_2 may be determined simultaneously with the Method 5 train provided that the following changes are made:

(i) The filter and impinger apparatus in sections 2.1.5 and 2.1.6 of Method 8 is used in place of the condenser (section 2.1.7) of Method 5.

(ii) All applicable procedures in Method 8 for the determination of SO_2 (including moisture) are used:

(4) For Method 6, Method 6C may be used. Method 6A may also be used whenever Methods 6 and 3B data are specified to determine the SO_2 emission rate, under the conditions in paragraph (d)(1) of this section.

(5) For Method 7, Method 7A, 7C, 7D, or 7E may be used. If Method 7C, 7D, or 7E is used, the sampling time for each run shall be at least 1 hour and the integrated sampling approach shall be used to determine the O_2 concentration $(\%O_2)$ for the emission rate correction factor.

(6) For Method 3, Method 3A or 3B may be used.

(7) For Method 3B, Method 3A may be used.

[54 FR 6662, Feb. 14, 1989; 54 FR 21344, May 17, 1989, as amended at 55 FR 5212, Feb. 14, 1990]

Subpart Da—Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978

SOURCE: 44 FR 33613, June 11, 1979, unless otherwise noted.

§ 60.40a Applicability and designation of affected facility.

(a) The affected facility to which this subpart applies is each electric utility steam generating unit:

(1) That is capable of combusting more than 73 megawatts (250 million Btu/hour) heat input of fossil fuel (either alone or in combination with any other fuel); and

(2) For which construction or modification is commenced after September 18, 1978.

(b) This subpart applies to electric utility combined cycle gas turbines that are capable of combusting more

Appendix E.6