TECHNICAL REVIEW DOCUMENT
FOR
OPERATING PERMIT 95OPBO059

to be issued to:

University of Colorado at Boulder, Power House
Boulder County
Facility ID 0130553

Prepared by Doris Jung on August 28, 1998

I. Purpose

This document will establish the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Colorado Title V Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA, during Public Comment, and for other interested parties. The conclusions made in this report are based on information provided in the application received on March 1, 1995 and additional information received on May 16, 1995, June 14, 1996 and August 27, 1998. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

On April 16, 1998 the Colorado Air Quality Control Commission directed the Division to implement new procedures regarding the use of short term emission and production/throughput limits on Construction permits. These procedures are being directly implemented in all operating permits that had not started their Public Comment period as of April 16, 1998. All short term emission and production/throughput limits that appeared in the construction permits associated with this facility that are not required by a specific State or Federal standard or by the above referenced Division procedures have been deleted and all annual emission and production/throughput limits converted to a rolling 12 month total. Note that, if applicable, appropriate modeling to demonstrate compliance with the National Ambient Air Quality Standards was conducted as part of the Construction Permit processing procedures. If required by this permit, portable monitoring results and/or EPA reference test method results will be multiplied by 8760 hours for comparison to annual emission limits unless there is a specific condition in the permit restricting hours of operation.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating

permit without applying for a revision to this permit or for an additional Construction Permit.

II. Source Description

The University of Colorado at Boulder (CU) consists of a Power House, a service building, a heating plant for a dormitory known as Williams Village, and miscellaneous insignificant activities around campus. The Power House, originally under the ownership of Trigon Engineering, is a co-generation plant producing electricity and steam. The Power House has two 16.5 MW turbines with the capability of firing either natural gas or No. 2 fuel oil. The exhaust gasses from the turbines are routed through two duct heaters with each unit having its own stack. The Power House also has two standby boilers which can fire either natural gas or No. 6 fuel oil and serve the purpose of backup steam generators to the heat recovery steam generators. Each backup unit has its own stack. CU requested separate Operating Permits for the Power House and the heating plant for Williams Village. The service building is classified as an insignificant source of emissions.

The Power House is located at the southeast corner of 18th Street and Colorado Avenue, which is approximately in the center of the CU campus. The area in which the plant operates is currently designated as nonattainment for carbon monoxide, particulate matter less than 10 μm and ozone. There are no affected states within 50 miles of the plant. The Federal Class I designated areas within 100 kilometers of the plant are Rocky Mountain National Park, Rawah Wilderness Area, and Eagle's Nest Wilderness Area.

Facility-wide emissions for pollutants of concern, Nitrogen Oxides (NO_x), Carbon Monoxide (CO), Volatile Organic Compounds (VOC), Sulfur Dioxide (SO_2), Particulate Matter (PM), Particulate Matter less than 10 microns (PM_{10}), and Hazardous Air Pollutants (HAPs) are as follows:

Pollutant	Facility-wide Potential* (tpy)	Facility-wide Actual** (tpy)
NO_x	< 250	116
CO	90	18.07
VOC	62.6	Negligible
SO_2	56.7	Negligible
PM	24.2	Negligible
PM_{10}	24.2	Negligible
HAPs	0.62	Negligible

*Based on worst case emissions for burning either primary (natural gas) or secondary fuel (No. 2 /No. 6 fuel oil)
**Actual emissions are based on the latest APEN on file

The Power House was originally equipped with four boilers that had a potential to emit greater than 250 tpy. In 1990, Trigon replaced two of the four boilers with two turbines and two duct heaters. During this modification, Trigon accepted emissions limits for the Power House in a synthetic minor permit for NO_x and CO (Colorado Construction Permit 89BO399). At this time, the area in which the facility is located was classified as nonattainment for PM_{10}, CO, and ozone. The facility-wide CO limit is 90.0 tpy. NO_x was not considered a precursor for PM_{10} until 1994; therefore, the facility-wide NO_x limit was set at less than 250.0 tpy. To ensure that the facility did not exceed these synthetic minor limits, a Continuous Emission Monitoring System (CEM) was installed to monitor NO_x and CO.

At the time the Colorado Construction Permit 89BO399 was issued, the Power House and the heating plant at Williams Village were considered separate sources. However, based upon more recent guidance, the Power House and the heating plant at Williams Village are considered a single source for NSR purposes. The heating plant has two boilers which have grandfathered status. Worst case PTE emissions and actual emissions for the Power House and the heating plant are as follows:

Pollutant	Source-wide Worst Case PTE (tpy)	Source-wide Actual (tpy)
NO_x	296.8	120.13
CO	117.8	19.10
VOC	67.3	0.11
SO_2	562.2	0.64
PM	28.9	0.45
PM_{10}	26.7	0.44
HAPs	0.62	0.62

As previously mentioned, the source is located in an area currently designated as nonattainment for PM_{10} and CO. Therefore, future modifications to the source which are in excess of significance levels defined in Colorado Regulation No. 3, Part A, Section I.B.58 shall result in the application of NSR review requirements. The Denver metropolitan area was previously designated by U.S. EPA as a nonattainment area for ozone. Under recently adopted revisions to the Federal Rules, the Denver metro area is no longer designated nonattainment. However, all SIP-approved requirements continue to apply in order to prevent backsliding under the provisions of Section 183(e) of the federal Clean Air Act.

As a co-generation facility that sells electricity, the Power House may be subject to the Acid Rain SO_2 Regulations. However, the facility is exempt from the Acid Rain SO_2 Regulations since it sells less than one-third of its potential electrical output capacity. The campus uses approximately 16 MW of 33 MW that could be potentially generated by the turbines. The facility has a contract with Public Service to sell 8 MW for profit. Electricity sold to Public Service beyond 8 MW receives substantially lower revenue.

Therefore, the facility has no incentive to sell more than one-quarter of its potential electrical output capacity.

This facility currently has no applicable MACTs but is subject to NSPS Standards of Performance for Stationary Gas Turbines (Colorado Regulation No. 6, Part A, Subpart GG, Federal 40 CFR § 60.330 through § 60.335). CU indicated that they are not subject to the provisions of 112(r). In their Title V application, the source certified compliance with all current applicable requirements.

III. Emission Sources

The following emission units are specifically regulated under terms and conditions of the Operating Permit for this site:

Units TU001, TU002, DU001, DU002, B003, and B004 - Facility-wide emission limits

All of these units are permitted under final approval facility-wide Colorado Construction Permit 89BO399. The facility-wide permit was issued to Trigon Engineering on July 3, 1990. A modification to Colorado Construction Permit 89BO399 was finalized on August 13, 1991. Colorado Construction Permit 89BO399 was transferred to CU on April 14, 1995. Emissions from all units shall not exceed the following facility-wide limits (Colorado Construction Permit 89BO399):

- NO_x: less than 250 tpy
- CO: 90.0 tpy
- VOC: 62.6 tpy
- PM: 24.2 tpy
- SO_2: 56.7 tpy

The source does not have PM_{10} emission limits. The PM_{10} emission factors listed below for each emission unit shall be used to determine emissions for APEN reporting purposes.

The source is required to submit quarterly reports of any required monitoring (Colorado Construction Permit 89BO399). All instances of deviations from any permit requirements must be clearly identified in the report.

Each emission unit has equipment-specific characteristics and requirements. The applicable requirements, emission factors, monitoring plan, and compliance status for each emission unit are described below.

Units TU001 and TU002 - Mitsubishi Turbines, Model MF-111AB, S/N: 0172 & 0173, 196 MMBtu/hr, NO_x steam injection, Natural Gas or No. 2 Fuel Oil Fired.

1. Applicable Requirements

These units are permitted under the final approval Colorado Construction Permit 89BO399. The exhaust gasses from each turbine are routed through a duct heater before they exit through the stack. There is one stack for each turbine/duct heater system. The turbines are subject to New Source Performance Standards (NSPS) Subpart GG requirements of Colorado Regulation No. 6, Part A - Standards of Performance for Stationary Gas Turbines (Federal 40 CFR 60.330 through 60.335) and Subpart A - General Provisions (Federal 40 CFR 60 Subpart A).

These turbines are also subject to the NSPS NO_x standard of 75 ppmvd. To ensure compliance with these standards, the turbines are equipped with NO_x steam injection to reduce NO_x emissions. CU has installed a Continuous Emissions Monitoring system (CEM) for each stack. The CEM is required to monitor NO_x and CO emissions and be operational no less than 90% of the time. The CEM sensor is placed downstream of both the turbine and its duct heater in the exhaust system where it measures the combined emissions of both emission units. The CEM shall be operating when either a turbine or a duct heater is in operation. CU monitors and records fuel consumption and the ratio of steam to fuel being fired in the turbine, as required by NSPS (Federal 40 CFR 60.334 (a)).

Colorado Construction Permit 89BO399 contains separate emission limits of NO_x for turbines and duct heaters. During the drafting of the Construction Permit, ambient impact modeling was performed without considering duct heater emissions. The potential emissions from the duct heaters are less than emissions from turbines and the turbines and heaters were originally permitted assuming that the duct heaters would not operate simultaneously with the turbines. However, CU has informed the Division that the duct heaters are occasionally fired when the turbines are operating. Since the CEM can not distinguish between turbine emissions and duct heater emissions, emissions from each stack shall be limited to 75 ppmvd NO_x in the Operating Permit. The NO_x limit is the NSPS NO_x standard described above.

It should be noted that the NSPS GG requirements also include monitoring of nitrogen content in the fuel to determine fuel-bound nitrogen allowances. In a memorandum issued by EPA on August 14, 1987 (attached), nitrogen monitoring can be waived when natural gas is used as fuel. The source is not allowed to claim any fuel-bound nitrogen content. Such allowances would increase the allowable NSPS NO_x standard. The CEM was installed to demonstrate compliance with the NSPS NO_x standard at zero fuel-bound nitrogen allowances, thus monitoring nitrogen content in No. 2 Fuel Oil would be redundant and will also be waived.

The applicable requirements for **each** turbine are as follows, unless otherwise stated:

- NO_x: 75 ppmvd[1,2]
- Facility-wide NO_x: less than 250 tpy (Colorado Construction Permit 89BO399)
- Facility-wide CO: 90.0 tpy (Colorado Construction Permit 89BO399)
- Facility-wide VOC: 62.6 tpy (Colorado Construction Permit 89BO399)
- Facility-wide PM: 24.2 tpy (Colorado Construction Permit 89BO399)
- Facility-wide SO_2: 56.7 tpy (Colorado Construction Permit 89BO399)
- Maximum Allowable Particulate Emissions Standard for fuel burning equipment (Colorado Regulation No. 1, Section III.A.1.b)

$$PE = 0.5(FI)^{-0.26}$$

Where: PE = Allowable Particulate emissions (lb/MMBtu)
FI = Fuel Input (MMBtu/hr)

- Sulfur content of the fuel being fired in the turbine shall be determined in accordance with Federal NSPS § 60.334, and established EPA Guidelines (Colorado Construction Permit 89BO399, Colorado Regulation No. 6, Part A, Subpart GG)
- Recordkeeping of steam to fuel ratio (Colorado Construction Permit 89BO399, Colorado Regulation No. 6, Part A, Subpart GG)
- CEM Availability greater than 90% (Colorado Construction Permit 89BO399)
- General Provisions of NSPS Subpart GG (Colorado Construction Permit 89BO399, Colorado Regulation No. 6, Part A, Subpart A)
- 20% Opacity limitation during normal operations (Colorado Regulation No. 1, Section II.A.1)
- APEN Reporting (Colorado Regulation No. 3, Part A, Section II)

[1]Corrected to 15% oxygen
[2]Emissions limits for each stack

SCENARIO I - NATURAL GAS FIRED

- Natural Gas use for both turbines combined is limited to 2775 MMscf/yr (Colorado Construction Permit 89BO399)

SCENARIO II - BACKUP No. 2 FUEL OIL FIRED

- No. 2 Fuel Oil use for both turbines combined is limited to 1430 thousand gal/yr (Colorado Construction Permit 89BO399)
- Sulfur content of No. 2 Fuel Oil shall not exceed 0.3 percent by weight (Colorado Construction Permit 89BO399)
- 30% Opacity during start-up, etc. (Colorado Regulation No. 1, Section II.A.4)

Streamlining of Applicable Requirements

According to Colorado Regulation No. 1, Section VI.B.4.(b) & (c), Colorado Regulation No. 6, Part B, Section II.D.(2) & (3), and Federal 40 CFR 60.333(a)&(b), the turbines are limited to 0.8 lb/MMBtu and 150 ppmvd SO_2 emissions. During the draft of Colorado Construction Permit 89BO399, impacts were estimated using ISC dispersion modeling. The modeling indicated that the short term SO_2 increments could be violated under certain operating conditions. Trigon requested a modification of the facility-wide permit to limit the weight sulfur content limitation of No. 2 fuel oil to 0.3%.

Natural Gas - The source is required to meet a SO_2 standard of 150 ppmvd at 15% oxygen. At an emission rate of 0.0006 lb SO_2/MMBtu, SO_2 emissions in ppm calculated with Method 19 is 0.12 ppm (see equation below), which is below the standard.

$$\text{ppm } SO_2 = \frac{0.0006 \text{ lb } SO_2}{\text{MMBtu}} \times \frac{\text{MMBtu}}{8710 \text{ scf}} \times \frac{(20.9 - 15)}{20.9} \times \frac{\text{ppm } SO_2}{1.66 \times 10^{-7} \frac{\text{lb } SO_2}{\text{scf}}} = 0.12 \text{ ppm } SO_2$$

The SO_2 emission factor for gas turbines used for electricity generation is 0.0006 lb SO_2/MMBtu, which is below the maximum allowable SO_2 emission standard of 0.8 lb SO_2/MMBtu. Therefore, compliance with the SO_2 standard of 0.8 lb SO_2/MMBtu and 150 ppmvd will be ensured by using natural gas.

No. 2 Fuel Oil - The SO_2 emission factor for turbines used for electricity generation is 1.00S lb SO_2 per 1000 gallons, where S is the percent sulfur content in the fuel. At a maximum No. 2 fuel oil sulfur content of 0.3%, the SO_2 emissions were determined as 0.3 lb SO_2/MMBtu (see equation below), which is below the maximum allowable SO_2 emission standard of 0.8 lb SO_2/MMBtu.

$$\frac{\text{lb } SO_2}{\text{MMBtu}} = 1.00 \ (0.3) \ \text{lb } SO_2 = 0.3 \ \frac{\text{lb } SO_2}{\text{MMBtu}}$$

The source is also required to meet a SO_2 standard of 150 ppmvd at 15% oxygen. At the above emission rate of 0.3 lb SO_2/MMBtu, SO_2 emissions in ppm calculated with Method 19 is 56 ppm (see equation below), which is below the standard.

$$\text{ppm } SO_2 = \frac{0.3 \text{ lb } SO_2}{\text{MMBtu}} \times \frac{\text{MMBtu}}{9910 \text{ scf}} \times \frac{(20.9 - 15)}{20.9} \times \frac{\text{ppm } SO_2}{1.66 \times 10^{-7} \frac{\text{lb } SO_2}{\text{scf}}} = 56 \text{ ppm } SO_2$$

Therefore, using No. 2 fuel oil with a maximum sulfur content of 0.3% will ensure compliance with the SO_2 standard of 150 ppmvd and 0.8 lb SO_2/MMBtu.

The sulfur limitation requested by Trigon was incorporated into the modified Colorado Construction Permit 89BO399 issued August 13, 1991. Therefore, the NSPS SO_2 standard and the Regulation No. 1 and No. 6 standard have been streamlined out by the limit of 0.3% sulfur by weight in No. 2 fuel oil and use of natural gas .

2. Emission Factors

Emissions from these turbines are produced during the combustion process, and are dependent upon the air to fuel ratio adjustment and specific properties of the natural gas being burned. The pollutants of concern are NO_x, CO, VOC, PM, and SO_2. NO_x and CO emissions are determined by the CEM. The emission factors for cogeneration turbines (EPA 450/4-90-003, March 1990) below have been converted to lb/MMBtu based on a fuel heating value of 1000 Btu/scf or 140 MMBtu/1000 gal and have been approved by the division for determining emissions from these turbines:

Pollutant	Natural Gas (lb/MMBtu)	No. 2 Fuel Oil (lb/MMBtu)
NO_x	CEM	CEM
CO	CEM	CEM
VOC	0.0126	0.0341
SO_2	0.0006	1.00(S)
PM	0.014	0.036
PM_{10}	0.014	0.034

(S) is the weight percent of sulfur in the fuel oil. The weight percent is multiplied by the emission factor to give an adjusted emission factor that takes the sulfur content of the fuel into account.

For each hour of CEM downtime the average hourly steam-to-fuel ratio shall be matched to an average hourly steam-to-fuel ratio from data recorded in the previous four weeks and the corresponding CEM emissions for NO_x and CO shall be used as an estimate for that hour. Any fraction of an hour of CEM unavailability shall be treated as a full hour for purposes of estimating emissions. The emissions estimated during CEM unavailability shall be recorded and added to the twelve month rolling total of emissions, as appropriate.

3. Monitoring Plan

Emissions of NO_x and CO will be determined with CEM data. Emissions of VOC, SO_2, PM, and PM_{10} will be determined using the emission factors listed. CU will be required

to conduct the emissions calculations on a monthly basis with quarterly reports and an annual compliance certification.

The data accuracy of the CEM shall be assessed by conducting a Cylinder Gas Audit (CGA) semi-annually per 40 CFR 60, Appendix F. The results of the audits shall be included in the reports required by Condition 1.2.

The Maximum Allowable Particulate Emissions Standard (Regulation No. 1, Section III.A.1.b) for these turbines are calculated below.

$$E = 0.5(16)^{-0.26} = 0.13 \frac{lb\ PM}{MMBtu}$$

Since the AP-42 PM emission factor for natural gas and No. 2 fuel oil are 0.014 lb PM/MMBtu and 0.036 lb PM/MMBtu, respectively, compliance with the Particulate Emissions Standard is ensured by burning natural gas and No. 2 fuel oil.

NO_x steam injection system will be operating when the turbine is operating. Per NSPS (Federal 40 CFR 60.332.f), the turbines are exempt from complying with the NSPS NO_x standard when ice fog is deemed a traffic hazard by the owner or operator of the turbine. Ice fog incidences shall be reported quarterly.

A revised APEN must be submitted to the Division as required by Colorado Regulation No. 3, Part A, Section II. C.

SCENARIO I - NATURAL GAS FIRED

The heat content of the natural gas used to fuel this turbine shall be verified semi-annually in accordance with ASTM Analysis Method D1826-77 or equivalent. The heat content of the natural gas shall be based on the lowest gross heating value of the fuel. Calculations of emissions required under Condition 2.2. shall be made using the heat content derived from the most recent required analysis. This analysis may be performed by the fuel vendor.

The Opacity standard of 20% will be monitored by the use of natural gas. Inspectors may verify this with EPA Method 9 opacity readings, if necessary.

SCENARIO II - BACKUP No. 2 FUEL OIL FIRED

The source shall record the sulfur content and heating value of each fuel shipment as received or test the tank contents after each shipment is received. These values will be used to determine emissions and compliance with the weight sulfur content limitation of

0.3%.

Opacity of emissions during normal operations shall not exceed 20% (Colorado Regulation No. 1, Section II.A.1). Compliance with this standard shall be determined by conducting visual observations in accordance with EPA Reference Method 9. Readings shall be conducted monthly, during normal operations, when No. 2 fuel oil is burned. If applicable, the reading shall be conducted within 24 hours of completion of the opacity reading as described under Condition 2.14. Results of Method 9 readings and a copy of the certified Method 9 reader's certification shall also be kept on site and made available to the Division upon request.

Opacity of emissions during fire building, cleaning of fireboxes, soot blowing, start-up, process modifications, or adjustment of control equipment shall not exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, Section II.A.4). Compliance with this standard shall be determined by conducting visual emission observations in accordance with EPA Reference Method 9. Readings shall be conducted within one hour of commencement of any of the above activities and every 24 hours thereafter during the activity.

4. Compliance Status

APENs reporting criteria emissions were filed with the Division for these turbines on September 12, 1994. No records indicating non-compliance were found in a review of the facility's APCD files. Therefore, these units are considered to be in compliance with all current applicable requirements.

Units DU001 and DU002 - Davis Duct Heater, Model and S/N: Unknown and Coen Duct Heater, S/N: 40D-13163-1, Both Rated at 66.6 MMBtu/hr, Natural Gas or No. 2 Fuel Oil Fired.

1. Applicable Requirements

These units are permitted under the final approval Colorado Construction Permit 89BO399. The duct heaters are subject to New Source Performance Standards (NSPS) Subpart Dc requirements of Regulation No. 6, Part A - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units (attached) and Subpart A - General Provisions (40 CFR 60 Subpart A). The duct heaters are located downstream of the turbines and can operate when the turbines are either on or off. CO emissions from the heaters shall be monitored by the CEM. The applicable requirements for **each** heater are as follows, unless otherwise stated:

- NO_x: 75 ppmvd[1, 2]

- Facility-wide NO_x: less than 250 tpy (Colorado Construction Permit 89BO399)
- Facility-wide CO: 90.0 tpy (Colorado Construction Permit 89BO399)
- Facility-wide VOC: 62.6 tpy (Colorado Construction Permit 89BO399)
- Facility-wide PM: 24.2 tpy (Colorado Construction Permit 89BO399)
- Facility-wide SO_2: 56.7 tpy (Colorado Construction Permit 89BO399)
- Maximum Allowable Particulate Emissions Standard for fuel burning equipment (Colorado Regulation No. 1, Section III.A.1.b)

$$PE = 0.5(FI)^{-0.26}$$

Where: PE = Allowable Particulate emissions (lb/MMBtu)
FI = Fuel Input (MMBtu/hr)

- CEM Availability greater than 90% (Colorado Construction Permit 89BO399)
- General Provisions of NSPS Subpart Dc (Colorado Construction Permit 89BO399, Colorado Regulation No. 6, Part A, Subpart A)
- 20% Opacity limitation during normal operations (Colorado Regulation No. 1, Section II.A.1)
- Quarterly Reporting (Colorado Regulation No. 6, Part A, Subpart Dc)
- APEN Reporting (Colorado Regulation No. 3, Part A, Section II)

[1]Corrected to 15% oxygen
[2]Emissions limits for the stack

SCENARIO I - NATURAL GAS FIRED

- Natural Gas use for both heaters combined is limited to 400 MMscf/yr (Colorado Construction Permit 89BO399)

SCENARIO II - BACKUP No. 2 FUEL OIL FIRED

- No. 2 Fuel Oil use for both heaters combined is limited to 288 thousand gal/yr (Colorado Construction Permit 89BO399)
- Sulfur content of No. 2 Fuel Oil shall not exceed 0.3 percent by weight (Colorado Construction Permit 89BO399)
- 30% Opacity during start-up, etc. (Colorado Regulation No. 1, Section II.A.4)

Streamlining of Applicable Requirements

NSPS Subpart Dc limits opacity at 20%, except for one 6-minute period per hour of not more than 27% opacity. This opacity standard shall apply at all times, except during periods of start-up, shutdown, or malfunction. However, according to Colorado Regulation No. 1, opacity shall not exceed 20% (Section II.A.1) and 30% (Section II.A.4) during fire building, cleaning of fire boxes, soot blowing, start-up, process

modification or adjustment of control equipment. Regulation No. 1 opacity standards are more stringent than the NSPS Subpart Dc opacity standards. Therefore, the NSPS Subpart Dc opacity standards have been streamlined out by the Regulation No. 1 opacity standards in the Operating Permit.

According to Colorado Regulation No. 1, Section VI.B.4.b and Colorado Regulation No. 6, Part B, Section II.D.3, the heaters are limited to 0.8 lb/MMBtu SO_2 emissions when firing fuel oil. Per Colorado Regulation No. 6, Part A, Subpart Dc, No. 2 fuel oil sulfur content shall not exceed 0.5 percent by weight. During the drafting of Colorado Construction Permit 89BO399, ambient impacts were estimated using ISC dispersion modeling. The modeling indicated that the short term SO_2 increments could be violated under certain operating conditions. Trigon therefore requested a modification of the facility-wide permit to limit the weight sulfur content limitation of No. 2 fuel oil to 0.3%.

At a weight sulfur content limitation of 0.3%, the SO_2 emissions for this fuel shipment from combustion were determined as 0.3 lb SO_2/MMBtu (see equation below), which is less than the maximum allowable SO_2 emission standard of 0.8 lb SO_2/MMBtu.

$$\frac{lb\ SO_2}{MMBtu} = \frac{1.01\ (0.3)\ lb\ SO_2}{MMBtu} = 0.3\ lb\ \frac{SO_2}{MMBtu}$$

Therefore, using No. 2 fuel oil with a maximum sulfur content of 0.3% will ensure compliance with both the SO_2 standard of 0.8 lb SO_2/MMBtu and the NSPS limit of 0.5 percent by weight.

The sulfur limitation requested by Trigon was incorporated into the modified Colorado Construction Permit 89BO399 issued August 13, 1991. Therefore, both the Regulation No. 1 standard and the NSPS limit have been streamlined out by the limit of 0.3% sulfur by weight in No. 2 fuel oil.

Colorado Regulation No. 6, Part A, Subpart Dc also requires daily recording of fuel use. CU will be required to record fuel consumption hourly. Therefore, the NSPS recording requirement for fuel use has been streamlined out by the hourly recordkeeping of fuel use.

2. Emission Factors

Emissions from these heaters are produced during the combustion process, and are dependent upon the specific properties of the fuel being burned. The pollutants of concern are NO_x, CO, VOC, SO_2, PM, and PM_{10}. NO_x and CO emissions are determined by the CEM. In the event that the CEM is unavailable and the turbines are

not running, duct heaters emissions of NOx and CO shall be estimated as set forth below. NO_x and CO emissions shall be estimated using the emission factors below and the average hourly fuel consumption. The emissions estimated during CEM unavailability shall be recorded and added to the twelve month rolling total of emissions, as appropriate.

SCENARIO I - NATURAL GAS FIRED

The AP-42 (EPA Compilation of Air Pollutant Emission Factors, March 1998) emission factors for small industrial boilers from Tables 1.4-1 and 2 have been converted to lb/MMBtu based on a heating value of 1020 Btu/scf.

Pollutant	Factor (lb/MMBtu)
NO_x	CEM / 0.0980
CO	CEM / 0.082
VOC	0.0054
SO_2	0.0006
PM	0.0075
PM_{10}	0.0075

SCENARIO II - BACKUP No. 2 FUEL OIL FIRED

The AP-42 (EPA Compilation of Air Pollutant Emission Factors, October 1996) emission factors for uncontrolled fuel oil combustion industrial boilers are taken from Tables 1.3-1, 2, 5 and converted to lb/MMBtu based on a heating value of 140 MMBtu/1000 gal. (S) is the weight percent of sulfur in the fuel oil.

Pollutant	Emission Factor (lb/1000 gal)
NO_x	CEM / 0.14
CO	CEM / 0.04
VOC	0.001
SO_2	1.01(S)
PM	0.0143
PM_{10}	0.00714

3. Monitoring Plan

CU shall record fuel consumption hourly and maintain a rolling twelve month total of consumption for each fuel. CU shall calculate emissions for fee purposes based on fuel consumption and the fuel based emission factors listed above. CU will be required to conduct the emissions calculations on a monthly basis with quarterly reports and an annual compliance certification.

The Maximum Allowable Particulate Emissions Standard (Regulation No. 1, Section III.A.1.b) for these heaters are calculated below.

$$E = 0.5(6.6)^{-0.26} = 0.17 \frac{lb\ PM}{MMBtu}$$

Since the AP-42 PM emission factor for natural gas and No. 2 fuel oil are 0.0075 lb PM/MMBtu and 0.0143 lb PM/MMBtu, respectively, compliance with the Particulate Emissions Standard is ensured by burning natural gas.

A revised APEN must be submitted to the Division as required by Colorado Regulation No. 3, Part A, Section II.C.

SCENARIO I - NATURAL GAS FIRED

The heat content of the natural gas used to fuel these heaters shall be verified semi-annually in accordance with ASTM Analysis Method D1826-77 or equivalent. The heat content of the natural gas shall be based on the lowest gross heating value of the fuel. Calculations of emissions required under Condition 3.1. and 3.2. shall be made using the heat content derived from the most recent required analysis. This analysis may be performed by the fuel vendor.

The Opacity standard of 20% will be monitored by the use of natural gas. Inspectors may verify this with EPA Method 9 opacity readings if necessary.

SCENARIO II - BACKUP No. 2 FUEL OIL FIRED

The source shall record the sulfur content and heating value of each fuel shipment as received or test the tank contents after each shipment is received. These values will be used to determine emissions and compliance with the weight sulfur content limitation of 0.3%.

Opacity of emissions during normal operations shall not exceed 20% (Colorado Regulation No. 1, Section II.A.1). Compliance with this standard shall be determined by conducting visual observations in accordance with EPA Reference Method 9. Readings shall be conducted monthly, during normal operations, when No. 2 fuel oil is burned. If applicable, the reading shall be conducted within 24 hours of completion of the opacity reading as described under Condition 3.10. Results of Method 9 readings and a copy of the certified Method 9 reader's certification shall also be kept on site and made available to the Division upon request.

Opacity of emissions during fire building, cleaning of fireboxes, soot blowing, start-up,

process modifications, or adjustment of control equipment shall not exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, Section II.A.4). Compliance with this standard shall be determined by conducting visual emission observations in accordance with EPA Reference Method 9. Readings shall be conducted within one hour of commencement of any of the above activities and every 24 hours thereafter during the activity.

4. Compliance Status

APENs reporting criteria emissions were filed with the Division for these heaters on September 12, 1994. No records indicating non-compliance were found in a review of the facility's APCD files. Therefore, these units are considered to be in compliance with all current applicable requirements.

Unit B003 - Combustion Engineering Boiler (tangential), Model VU-5E, S/N: 5970, 125 MMBtu/hr, Natural Gas or No. 6 Fuel Oil Fired.

Unit B004 - Erie City Boiler, Model 2DR, S/N: 97294, 151 MMBtu/hr, Natural Gas or No. 6 Fuel Oil Fired.

1. Applicable Requirements

These units are permitted under the final approval Colorado Construction Permit 89BO399. Boilers B003 and B004 were installed in 1958 and 1966, respectively. The boilers are permitted to burn natural gas as the primary fuel and No. 6 fuel oil as the back-up fuel. The applicable requirements for the boilers are as follows:

- Facility-wide NO_x: less than 250 tpy (Colorado Construction Permit 89BO399)
- Facility-wide CO: 90.0 tpy (Colorado Construction Permit 89BO399)
- Facility-wide VOC: 62.6 tpy (Colorado Construction Permit 89BO399)
- Facility-wide PM: 24.2 tpy (Colorado Construction Permit 89BO399)
- Facility-wide SO_2: 56.7 tpy (Colorado Construction Permit 89BO399)
- Maximum Allowable Particulate Emissions Standard for fuel burning equipment (Colorado Regulation No. 1, Section III.A.1.b)

$$PE = 0.5(FI)^{-0.26}$$

Where: PE = Allowable Particulate emissions (lb/MMBtu)
FI = Fuel Input (MMBtu/hr)

- 20% Opacity limitation during normal operations (Colorado Regulation No. 1,

Section II.A.1)
- APEN Reporting (Colorado Regulation No. 3, Part A, Section II)

SCENARIO I - NATURAL GAS FIRED

- Natural Gas use for both boilers combined is limited to 666 MMscf/yr (Colorado Construction Permit 89BO399)

SCENARIO II - BACKUP No. 6 FUEL OIL FIRED

- No. 6 Fuel Oil use for both boilers combined is limited to 193 thousand gal/yr (Colorado Construction Permit 89BO399)
- Sulfur content of No. 6 Fuel Oil shall not exceed 0.85 percent by weight (Colorado Construction Permit 89BO399)
- 30% Opacity during start-up, etc. (Colorado Regulation No. 1, Section II.A.4)

CU currently has a supply of No. 6 fuel oil with a sulfur content of 0.92% by weight. This supply was purchased prior to the issuance of Colorado Construction Permit 89BO399. CU has made plans to replace No. 6 fuel oil with No. 2 fuel oil in 1999. A compliance plan detailing this change has been included in the Operating Permit.

Streamlining of Applicable Requirements

According to Colorado Regulation No. 1, Section VI.A.3.b, the boilers are limited to 1.5 lb/MMBtu SO_2 emissions when firing fuel oil. During the draft of Colorado Construction Permit 89BO399, impacts were estimated using ISC dispersion modeling. The modeling indicated that the short term SO_2 increments could be violated under certain operating conditions. Trigon requested a modification of the facility-wide permit to limit the weight sulfur content limitation of No. 6 fuel oil to 0.85%.

At a sulfur content of 0.85%, the SO_2 emissions for this fuel shipment from combustion were determined as 0.95 lb SO_2/MMBtu (see equation below), which is less than the maximum allowable SO_2 emission standard of 1.5 lb SO_2/MMBtu. Therefore, using No. 6 fuel oil with a maximum sulfur content of 0.85% will ensure compliance with the SO_2 standard of 1.5 lb SO_2/MMBtu.

$$\frac{lb\ SO_2}{MMBtu} = \frac{1.12\ (0.85)\ lb\ SO_2}{MMBtu} = 0.95\ lb\ \frac{SO_2}{MMBtu}$$

The SO_2 emissions are determined at 1.03 lb SO_2/MMBtu for the existing supply of No. 6 fuel oil with a sulfur content of 0.92%, which is also less than the maximum allowable SO_2 emission standard of 1.5 lb SO_2/MMBtu.

The sulfur limitation requested by Trigon was incorporated into the modified Colorado Construction Permit 89BO399 issued August 13, 1991. Therefore, the Regulation No. 1 standard has been streamlined with a limit of 0.85% sulfur by weight in No. 6 fuel oil.

2. Emission Factors

Emissions from these boilers are produced during the combustion process, and are dependent upon the specific properties of the fuel being burned. The pollutants of concern are NO_x, CO, VOC, SO_2, PM, and PM_{10}.

SCENARIO I - NATURAL GAS FIRED

The AP-42 (EPA Compilation of Air Pollutant Emission Factors, March 1998) emission factors for large industrial boilers from Tables 1.4-1 and 2 are based on a heating value of 1020 Btu/scf. The NO_x and CO emission factors for tangential boilers fired with natural gas are used for B003.

Pollutant	B003 (lb/MMBtu)	B004 (lb/MMBtu)
NO_x	0.167	0.275
CO	0.024	0.082
VOC	0.0054	0.0054
SO_2	0.0006	0.0006
PM	0.0075	0.0075
PM_{10}	0.0075	0.0075

SCENARIO II - BACKUP No. 6 FUEL OIL FIRED

The AP-42 (EPA Compilation of Air Pollutant Emission Factors, October 1996) emission factors for uncontrolled fuel oil combustion industrial boilers are taken from Tables 1.3-1, 2 and 5 based on a heating value of 140 MMBtu/1000 gal. (S) is the weight percent of sulfur in the fuel oil.

Pollutant	Emission Factor (lb/MMBtu)
NO_x	0.39
CO	0.04
VOC	0.002
SO_2	1.12(S)
PM	0.498(S) + 0.175
PM_{10}	0.471(S) + 0.165

3. Monitoring Plan

CU shall calculate emissions for fee purposes based on fuel consumption and the fuel based emission factors listed above. CU will be required to conduct the emissions calculations on a monthly basis with quarterly reports and an annual compliance certification.

The Maximum Allowable Particulate Emissions Standard (Colorado Regulation No. 1, Section III.A.1.b) for these boilers are calculated below.

B003: $$E = 0.5(15)^{-0.26} = 0.14 \frac{lb}{MMBtu}$$

B004: $$E = 0.5(11)^{-0.26} = 0.14 \frac{lb}{MMBtu}$$

Since the AP-42 PM emission factor for natural gas is 0.0075 lb/MMBtu, compliance with the Particulate Emissions Standard may be ensured by burning natural gas. The AP-42 PM emission factor for No. 6 fuel oil at 0.85% sulfur content is 0.598 lb/MMBtu, which exceeds the Particulate Emissions Standard. The source is currently burning an existing supply of No. 6 fuel oil, which was purchased prior to the issuance of Colorado Construction Permit 89BO399, with a sulfur content of 0.92%. The sulfur content of the current supply of No. 6 fuel oil is not in compliance with the permit sulfur content limit of 0.85%. A compliance plan has been incorporated into the Operating Permit to bring these units into compliance by December 1999. CU is planning to burn No. 2 fuel oil instead No. 6 fuel oil by late fall of 1999. Construction to replace No. 6 fuel oil tanks with No. 2 fuel oil tanks will begin in Spring 1999. CU's plan to burn a cleaner back-up fuel has been incorporated into the compliance plan.

A revised APEN must be submitted to the Division as required by Colorado Regulation No. 3, Part A, Section II.C.

SCENARIO I - NATURAL GAS FIRED

The heat content of the natural gas used to fuel these boilers shall be verified semi-annually in accordance with ASTM Analysis Method D1826-77 or equivalent. The heat content of the natural gas shall be based on the lowest gross heating value of the fuel. Calculations of emissions required under Condition 4.1 and 5.1. shall be made using the heat content derived from the most recent required analysis. This analysis may be performed by the fuel vendor.

The Opacity standard of 20% will be monitored by the use of natural gas. Inspectors may verify this with EPA Method 9 opacity readings if necessary.

SCENARIO II - BACKUP No. 6 FUEL OIL FIRED

The source shall record the sulfur content and heating value of each fuel shipment as received or test the tank contents after each shipment is received. These values will be used to determine emissions and compliance with the weight sulfur content limitation of 0.3%.

Opacity of emissions during normal operations shall not exceed 20% (Colorado Regulation No. 1, Section II.A.1). Compliance with this standard shall be determined by conducting visual observations in accordance with EPA Reference Method 9. Readings shall be conducted monthly, during normal operations, when No. 6 fuel oil is burned. If applicable, the reading shall be conducted within 24 hours of completion of the opacity reading as described under Condition 4.8. and 5.8. Results of Method 9 readings and a copy of the certified Method 9 reader's certification shall also be kept on site and made available to the Division upon request.

Opacity of emissions during fire building, cleaning of fireboxes, soot blowing, start-up, process modifications, or adjustment of control equipment shall not exceed 30% for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, Section II.A.4). Compliance with this standard shall be determined by conducting visual emission observations in accordance with EPA Reference Method 9. Readings shall be conducted within one hour of commencement of any of the above activities and every 24 hours thereafter during the activity.

4. Compliance Status

APENs reporting criteria emissions was filed with the Division for these boilers September 12, 1994. These units are not in compliance with the permit sulfur content limit for No. 6 fuel oil. CU is planning to switch to a cleaner burning fuel, No. 2 fuel oil, by late fall of 1999. Therefore, a compliance plan has been incorporated into the Operating Permit which requires that CU cease burning No. 6 fuel oil and switch to burning No. 2 fuel oil by the December 1, 1999.

IV. Insignificant Activities

A list of insignificant activities was provided with the application. These activities do not pose a significant threat to air quality. These items were placed in an appendix in the proposed permit so that they would be of use during inspection. Of specific interest:

Underground Storage Tank

There are five 10,000 gal underground storage tanks that hold fuel oil. The annual

throughput for each tank is less than 400,000 gallons. Therefore, these tanks are considered insignificant activities under Colorado Regulation No. 3, Part C, Section II.E.3.fff.

V. Alternative Operating Scenarios

Units TU001, TU002, DU001, and DU002 have an alternative operating scenario to burn No. 2 fuel oil as a back-up fuel. Units B003 and B004 have an alternative operating scenario to burn No. 6 fuel oil as a back-up fuel.

VI. Permit Shield

No specific regulations were cited by CU as non-applicable to this source.

VII. Short Term Limits Deleted from Operating Permit

Construction Permit	Emission Unit	Short Term Limit
89BO399	B003	NO_x: 68.8 lb/hr
		CO: 5.00 lb/hr
		VOC: 0.17 lb/hr
		PM: 1.74 lb/hr
		SO_2: 105.90 lb/hr
	B004	NO_x: 83.10 lb/hr
		CO: 6.04 lb/hr
		VOC: 0.21 lb/hr
		PM: 2.10 lb/hr
		SO_2: 128.01 lb/hr
	DU001 and DU002	NO_x: 25.2 lb/hr
		CO: 5.3 lb/hr
		VOC: 1.8 lb/hr
		PM: 2.1 lb/hr
		SO_2: 45.2 lb/hr
	TU001 and TU002	CO: 38.4 lb/hr
		VOC: 9.8 lb/hr
		PM: 6.8 lb/hr
		SO_2: 59.0 lb/hr