TECHNICAL REVIEW DOCUMENT
for
OPERATING PERMIT 96OPBO131
to be issued to:

Public Service Company - Valmont Station
Boulder County
Source ID 0130001

Prepared on August 25, 1997
Revised on March 30, May 8, June 22, August 13, November 3 & 20, 1998 and January, March and May 2001
Revised June 2001 based on comments received during the Public Comment Period
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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 Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA and during Public Comment. The conclusions made in the report are based on information provided in the original application submittal of February 15, 1996, additional technical information submitted November 15, 1996, June 18, July 24 and December 8, 1998 and December 12, 2000, comments on the draft permit received September 30, October 23 and December 23, 1998 and April 27, 2001, comments on the draft permit received during the Public Comment period, e-mail correspondence and telephone conversations with the source. 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 or revised construction permit.

The word "credible" as it is used in the term "credible evidence" shall be applied under the provisions of the permit as defined by Colorado and Federal Rules of Evidence.

II. Source Description:

This source is classified as an electric services facility under Standard Industrial Classification 4911. Electricity is produced through one 199 MW coal/natural gas-fired boiler and one 50 MW natural gas/No. 2 fuel oil-fired combustion turbine. The boiler is equipped with low-NO_X burners and over-fire air. Emissions from this boiler pass through a bag-house to reduce particulate emissions. In addition, Valmont station has a natural gas fired auxiliary boiler to provide heat for the facility when the main boiler is not functioning. Other emission sources at Valmont include fugitive emissions from coal handling and storage, ash handling and disposal and from traffic on paved and/or unpaved roads. Finally, Valmont station has point source emissions from the ash silo, the coal crusher and several Safety-Kleen cold cleaners that have applicable requirements and therefore have been included in the Operating Permit.

This facility is located in Boulder at 1800 N. 63rd Street in Boulder county. This facility is located in an area that has been designated as non-attainment for Carbon Monoxide and PM_{10}. In addition, as of January 16, 2001 the area is also classified as non-attainment for the 1-hour ozone standard. As of the issue date of this permit, the State has submitted both ozone and CO attainment/maintenance plans to EPA. An attainment/maintenance plan for PM_{10} has been approved by the Air Quality Control Commission (AQCC) and should be submitted to EPA in the summer of 2001. If EPA approves the plans, the Denver metro area will be reclassified as attainment/maintenance for CO, PM_{10} and ozone. Under that classification, all SIP-approved emission control standards will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act.

Rocky Mountain National Park and Eagles Nest and Rawah National Wilderness Area, all Federal Class I designated areas are within 100 km of this facility. There are no affected states within 50 miles of this facility.

This facility is a major stationary source for the purposes of PSD and non-

attainment area major New Source Review (NSR), however, it was constructed prior to the adoption of PSD/non-attainment area major NSR regulations and the implementation of best available control technology (BACT) and lowest achievable emission rate (LAER). Based on the information available to the Division and supplied by the applicant, the Division believes that modifications up to this point have not triggered PSD or non-attainment area major NSR review. For purposes of future PSD or non-attainment area major NSR review, Black Hill's Colorado, LLC combustion turbines (currently permitted under Colorado Construction Permit 99BO0474) shall be considered in conjunction with this facility. Note that Black Hills Colorado, LLC will be submitting an Operating Permit application in the near future and Operating Permit 01OPBO238 has been assigned for this facility. Although the emissions from the Black Hill's Colorado, LLC combustion turbine must be considered by Public Service Company when performing either PSD or major non-attainment area NSR review, Public Service Company asserts that the operation of this unit in accordance with construction permit 99BO0474 is the sole responsibility of Black Hill's Colorado, LLC. Emissions at the facility are as follows:

Pollutant	Potential to Emit - 100% Coal[1]	Potential to Emit - 100% Natural Gas[2]	Actuals - Combination of Fuels
PM[3]	2,866.4 (2,866.4)	1,582 (1,582)	100.39
PM_{10}	1,505.1 (1,505.1)	723.4 (723.4)	43.29
SO_2[4]	14,691 (14,691)	14,691 (14,691)	2,835.92
NO_X[5]	4,734.4 (5,386.4)	4,734.4 (5,386.4)	896.1
CO	453.8 (301.8)	596.8 (444.8)	102.75
VOC	81.3 (64.3)	73.3 (56.3)	14.2
Pb	.65	Negl.	Negl.
HAPs[6]	132.1	Negl.	45.4

[1]Boiler is firing 100% coal includes emissions from coal and ash handling
[2]Boiler if firing 100% natural gas does not include emissions from coal and ash handling
( ) turbine burning 100% No. 2 fuel oil
[3]PTE for boiler and turbine based on 0.1 lbs/mmBtu x design heat rate x 8760 hrs/yr, auxiliary boiler PTE based on 0.22 lbs/mmBtu x design heat rate x 8760 hrs/yr
[4]boiler PTE based on 1.1 lbs/mmBtu x design heat rate x 8760 hrs/yr, turbine PTE based on 0.8 lbs/mmBtu x design heat rate x 8760 hrs/yr
[5]boiler PTE based on 0.45 lbs/mmBtu x design heat rate x 8760 hrs/yr
[6]PTE include uncontrolled metallic HAPs, control efficiencies range from 78.2 - 99.8 for these compounds

Potential to emit for the boilers and the turbine is based on the information identified in the table and the maximum hourly fuel consumption rate, AP-42 emission factors and 8760 hrs/yr of operation. Potential to emit from coal handling, ash handling and haul roads is based on information supplied in the Title V application for regulated units. Actual emissions are based on the Division's 1999 inventory. Hazardous Air Pollutant (HAP) Emissions, both potential to emit and actual are based on APENs submitted September 30, 1996 (identifying mainly metallic HAPs), using 1995 data,

as a result of the Division=s request for public utilities to submit HAP addendums (APENs) on their boilers and information from the Division's 1999 inventory (HCl and HF).

The source indicated that this facility is not subject to 112(r), the Accidental Release Requirements.

The main boiler is subject to the title IV Acid Rain provisions.

III. Emission Sources:

The following sources are specifically regulated under terms and conditions of the Operating Permit for this Site.

A. Unit B001: Combustion Engineering Boiler, Model and Serial No. 19695, Rated at 1,845 mmBtu/hr. Coal-Fired with Natural Gas Used as Back-Up.

1. Applicable Requirements - This unit was first placed in service in May 1964. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 1,845 mmBtu/hr. This maximum can vary somewhat depending on the quality of the fuel used. This unit has a maximum continuous steam flow rating of 1,380,000 lbs/hr. This maximum steam flow rating cannot be exceeded.

An Ecolaire fabric filter baghouse was added in April 1984. This addition to the boiler did not constitute a modification because no increase in emissions occurred.

Low NO_X burners were installed in May of 1990 and modified in June of 1995. Although this addition will reduce NO_X emissions, the Division believes that CO emissions could be increased as a result. An increase in CO emissions could subject this unit to further permitting requirements. The following discussion addresses these permitting issues.

Revisions (WEPCO rule, May 20, 1992) made to the federal PSD (40 CFR Part 52.21) and major non-attainment area NSR (40 CFR Part 52.24) requirements, **exempted** the addition, replacement or use of a pollution control project at existing electric utility steam generating units **unless** the project would A...result in a significant net increase in representative actual annual emissions of any criteria pollutant over levels used for that source in the most recent air quality impact analysis in the area conducted for the purpose of Title I <u>and</u> if the Administrator determines that the increase will cause or contribute to a violation of any NAAQS or PSD increment.@ These units are grandfathered from PSD and major non-attainment area NSR review, were never modified and subsequently were never modeled. Therefore, the addition of the low NO_X burners would not subject this unit to major PSD or non-attainment area review in accordance with the WEPCO rule.

An increase in the hourly emission rate of any regulated pollutant would subject these units to federal (40 CFR Part 60, as adopted by reference in Colorado Regulation No. 6, Part A) and state-only NSPS (Colorado Regulation No. 6, Part B) requirements. The Division believes that emissions of CO may be increased by the addition of the low NO_X burners and since CO is not a regulated pollutant under the federal NSPS (40 CFR Part 60 D, Da and Db, as adopted by reference in Colorado Regulation No. 6, Part A) or state-only NSPS (Reg 6, Part B, Section II), the Division has determined that no NSPS requirements would apply.

Finally, if the addition of the low NO_X burners would increase emissions of CO, then the minor NSR permitting requirements in Reg 3, Part B would apply. The installation of these low NO_X burners occurred in 1990. At this time, the Division did not express any concern over an associated increase in CO emissions that might result with the addition of low NO_X burners and therefore no official pre and post modification testing was done to determine whether the addition of the low NO_X burners would increase CO emissions. Baseline testing was performed on the boiler in 1986, prior to installation of the low NO_X burners. After installation of the low NO_X burners, an acceptance test was conducted on the boiler. The test included limited data for CO emissions, but the data indicated that there were low levels of CO in nearly all the optimization tests and that CO levels after installation of the low NO_X burners were similar to those in the 1986 baseline test. Recently pre and post modification testing has been conducted by Public Service Company on Hayden Units 1 and 2 and Cherokee Unit 1 and the results indicate that there was no increase in CO emissions with the addition of low NO_X burners. In addition, low NO_X burners were installed on Arapahoe Unit 4 as part of a Department of Energy Clean Coal Technology Round 3 program. As part of the program CO emissions were tested before and after the addition of the low NO_X burners. Test results indicated that there was no increase in CO emissions with the addition of the low NO_X burners. Therefore, the Division believes that the minor NSR permitting requirements in Reg 3, Part B do not apply to the addition of the low NO_X burners.

Therefore, this boiler can be considered a Agrandfathered@ source and therefore is exempt from Colorado Construction Permit requirements because this unit was in service and last modified prior to February 1, 1972. As a grandfathered unit, this boiler has the following applicable requirements:

- Opacity shall not exceed 20%,except as provided for in Reg 1, Section II.A.4 (Reg 1, Section II.A.1)
- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment, when burning coal (Reg 1, Section II.A.4)
- Particulate emissions shall not exceed 0.1 lbs/mmBtu (Reg 1, Section III.A.1.c)
- Continuous emission monitoring requirements (Reg 1, Section IV)

- A continuous emission monitoring system for the measurement of opacity shall be installed, calibrated, maintained and operated, when burning coal (Reg 1, Section IV.B.1)
- Either a continuous emission monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained and operated or a Division approved sampling plan shall be developed and implemented for determining the amount of sulfur in the fuel in order to calculate sulfur oxide emissions (Reg 1, Section IV.B.2)
- If continuous emission monitor for SO_2, then continuous emission monitor for either O_2 or CO_2 (Reg 1, Section IV.B.3)
- Calibration of continuous emission monitors (Reg 1, Section IV.F)
- Notification and Recordkeeping (Reg 1, Section IV.G)
- Recordkeeping duration (Reg 1, Section IV.H)
- Reporting requirements – if fuel sampling (Reg 1, Section VI.I)

- Sulfur dioxide emissions shall not exceed 1.2 lbs/mmBtu, when burning coal (Reg 1, Section VI.A.3.a.(ii))
- Emission requirements for certain electric generating facilities which include (Reg 1, Section VII.A.3):
  - NO_X emissions not to exceed 0.45 lbs/mmBtu, calculated on a 30 day rolling average
  - SO_2 emissions not to exceed 1.1 lbs/mmBtu calculated as a 3 hour rolling average
  - Source shall install, certify and operate continuous emission monitoring equipment for measuring opacity, SO_2, NO_x and either CO_2 or O_2 no later than January 1, 1995
- APEN reporting (Reg 3, Part A, Section II)
- Lead (Pb) emissions shall not be such that emissions result in an ambient lead concentration exceeding 1.5 Fg/SCM averaged over a one-month period (Reg 8, Part C) - This is a **State-only** requirement
- Acid Rain Requirements as follows:
  - This unit has been allocated, on an annual basis, SO_2 allowances as listed in 40 CFR 73.10(b). If annual SO_2 emissions exceed the allocated allowances for that year, additional allowances must be obtained per 40 CFR Part 75 to cover emissions for that particular calendar year.
  - NO_x emissions of 0.45 lbs/mmBtu on an annual average basis (source opted to comply with Phase I limits (' 76.5(a)(1) by early election (' 76.8))
  - Acid rain permitting requirements per 40 CFR Part 72.
  - Continuous emission monitoring requirements per 40 CFR Part 75.
  - This source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emissions (40 CFR Part 77).

Streamlining of Applicable Requirements

Continuous Emission Monitors

There are multiple requirements for Continuous Emission Monitoring (CEM)/Continuous Opacity Monitoring (COM) systems. Colorado Regulation No. 1, Section IV requires a COM (when burning coal) and either a CEM for SO_2 or fuel sampling. If a CEM is used for monitoring SO_2, then a CEM is required for either CO_2 or O_2. Regulation 1, Section IV identifies other requirements for CEMs such as performance specifications, calibration, notification and recordkeeping and requirements for record retention. This unit is also required by Regulation No. 1, Section VII.A.3 to have CEMs for opacity, SO_2, NO_X and either CO_2 or O_2. This unit is also subject to the Acid Rain Requirements and as such is required to continuously measure and record emissions of SO_2, NO_X (and diluent gas either CO_2 or O_2), and CO_2 as well as volumetric flow, and opacity. The Acid Rain CEM requirements are specified in 40 CFR Part 75. The general requirement to install, calibrate, operate and maintain COMs/CEMs from Reg 1, Section A & B and Reg 1, Section VII.A.2 will be streamlined out in favor of the Acid Rain CEM requirements as they are more stringent. Streamlining of more specific CEM requirements is addressed in the paragraph below.

The performance specification requirements for these CEMS will be subject to the Acid Rain requirements (40 CFR Part 75), since Reg 1, Section IV.E CEM performance specification requirements do not apply to this unit. The CEMs and COM will be subject to the QA/QC requirements in 40 CFR Part 75 as Reg 1 does not identify specific QA/QC requirements. In the case of the COM, the QA/QC requirements in Part 75 reference 40 CFR Part 51, Appendix M and the reference method in Appendix M that addresses COMs (RM 203) has not been promulgated as of this date. Therefore, the calibration requirements in Reg 1, Section IV.F will be included in the permit to identify the QA/QC requirements for the COM. The excess emissions notification requirements from Regulation 1, Section IV.G have been included in the Operating Permit. The Reg 1, Section IV.H requirements for record retention shall be streamlined out of the permit in favor of the Reg 3, Part C, records retention requirements (General Conditions No. 21.b & c).

<u>Sulfur Dioxide (SO_2)</u>

This unit is subject to two different lbs/mmBtu SO_2 standards. The standard in Regulation No. 1, Section VI.A.3.a.(ii) standard is 1.2 lbs/mmBtu on a 3-hour rolling average (note Regulation No. 1, Section VI.A.1 provides for an average time if not otherwise specified in the regulation). The Regulation No. 1, Section VII.A.3 standards are 1.1 lbs/mmBtu calculated as a 3-hour rolling average. Since the Regulation No. 1, Section VII.A.3 standard is more stringent it has been included in the Operating Permit.

Finally, there is an Acid Rain SO_2 limit, which is a ton/yr limit based on the number of allowances (1 allowance = 1 ton per year of SO_2) a unit has available. The number of allowances can increase or decrease for a unit depending on allowance availability and more allowances can be obtained for a unit that exceeds its allotment without being considered a violation, provided allowances are obtained by

the deadline. Allowances are obtained through EPA, other units operated by the utility or the allowance trading market and compliance information is submitted (electronically) to EPA. Pursuant to Regulation No. 3, Part C, Section V.C.1.b, if a federal requirement is more stringent than an Acid Rain requirement, both requirements shall be incorporated into the permit and shall be federally enforceable. For these reasons, the Acid Rain SO_2 requirements have not been streamlined out of the permit. The source will have to demonstrate compliance with both the Acid Rain and Regulation No. 1, Section VII.A.3 standards. Note that the Acid Rain SO_2 limitation appears only in Section III (Acid Rain Requirements) of the permit.

Nitrogen Oxides (NO_X)

This source is subject to both the Regulation No. 1, Section VII.A.3 standards and the Acid Rain NO_X requirements. The Acid Rain NO_X requirement is 0.45 lbs/mmbtu based on a calendar annual average. The Regulation No. 1, Section VII.A.3 standard is 0.45 lbs/mmbtu, based on a 30-day rolling average. Although the Acid Rain NO_X requirements and the Regulation No. 1, Section VII.A.3 standards appear to be equivalent, it is possible that the source could deviate from the Regulation No. 1, Section VII.A.3 30 day rolling average and still comply with the Acid Rain NO_X requirement. In addition, NO_X data used to determine compliance with the Acid Rain requirements are submitted (electronically) to EPA for compliance demonstration. In addition, Regulation No. 3, Part C, Section V.C.1.b, requires that if a federal requirement is more stringent than an Acid Rain requirement, both requirements shall be incorporated into the permit and shall be federally enforceable. Therefore, for these reasons the NO_X requirements have not been streamlined. The source will have to demonstrate compliance with both the Acid Rain and Regulation No. 1, Section VII.A.3 requirements. Note that the Acid Rain NO_X limitations only appear in Section III (Acid Rain Requirements) of the permit.

2. Emission Factors - Emissions from these boilers are from combustion of fossil fuels. Type and quantities of emissions are dependent on the fuels being burned. This unit burns primarily coal; however, natural gas may be used as back-up fuel. The pollutants of concern are Particulate Matter, (PM and PM_{10}), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC). Some hazardous air pollutants (HAPs) are generated through the combustion process. Approval of emission factors for this unit is necessary to the extent that accurate actual emissions are required to verify the need to submit Revised APENs to update the Division=s Emission Inventory.

The source proposed to use emission factors from EPA=s Compilation of Emission Factors (AP-42), for coal combustion - Section 1.1 (9/98), Tables 1.1-3, 1.1-6 and 1.1-19 for pre-NSPS tangentially fired boilers burning subbituminus coal and for natural gas - Section 1.4 (3/98), Tables 1.4-1 and 1.4-2 for tangentially fired boilers.

The proposed emission factors are as follows:

Pollutant	Emission Factor (Coal)	Emission Factor (Natural Gas)
PM	Source Test	1.9 lbs/mmCF
PM_{10}	0.92(PM)	1.9 lbs/mmCF
SO_2	CEM	CEM
NO_X	CEM	CEM
CO	0.5 lbs/ton	24 lbs/mmCF
VOC	0.06 lbs/ton	5.5 lbs/mmCF

Lead emissions shall be calculated as follows:

Lead emissions (tons/yr) = Ash emitted x quantity of lead in ash

$$\text{Ash emitted (tons/yr)} = \frac{\text{10A lbs ash/ton coal x quantity of coal burned (tons/yr)}}{\text{2000 lbs/ton}}$$

where: A = weight percent ash in coal (10A is the AP-42 (Section 1.1, dated 9/98) emission factor for PM)

$$\text{Quantity of Lead in Ash (lbs/lbs)} = \frac{\text{content of lead in coal (ppm)}}{\text{content of ash in coal (wt \%)}} \times 10^{-4}$$

The source will be required to use their CEMs to determine annual emissions of SO_2 and NO_X for the purposes of APEN reporting and payment of fees. The emission factor for PM (coal combustion) shall be determined by annual source testing of the boiler.

This boiler is equipped with a baghouse and low NO_X burners with over-fire air to control particulate and NO_X emissions respectively. Provided the source maintains the baghouse per manufacturer=s recommendations and good engineering practices, a 99.9% efficiency can be applied to the PM and PM_{10} emission factors when burning natural gas and an efficiency of 99.3% can be included in the lead emission calculation when burning coal. The permit will not specifically identify any maintenance requirements for the low NO_X burner since the source will be required to use their CEM to determine NO_X emissions.

3. Monitoring Plan - Compliance demonstration and monitoring requirements for this unit are identified in Sections 1-3 of Section II of the draft Operating Permit. Conditions 1.1 through 1.12 address coal burning and 2.1 through 2.10 address natural gas burning. Condition 3.1 addresses the firing of a combination of fuels.

Since the source is required to install, certify and operate continuous emission monitoring equipment for opacity, SO_2, NO_X (including diluent gas either CO_2 or O_2), CO_2 and volumetric flow, the Division will require the source to use their CEM/COM to demonstrate compliance with the opacity, SO_2 and NO_X requirements. When

burning natural gas, the Division will not require the source to use the CEM to monitor compliance with the SO_2 requirements, since ' 75.10(d) does not require the source to use the CEM to determine SO_2 emissions [' 75.11(e) exception as identified in ' 75.10(d)].

Operation of the CEM/COM in accordance with the requirements in 40 CFR Part 75 (Acid Rain Continuous Emission Monitoring Requirements) is sufficient to satisfy the requirements for operating the CEM/COM system. Part 75 defines the QA/QC requirements for the COM in ' 75.21(b) and indicates that the COM shall be operated, maintained and calibrated in accordance with the procedures in 40 CFR Part 51, Appendix M. Appendix M addresses EPA reference methods and no reference methods listed appears to address opacity monitors. It appears that this reference is an error. However, the EPA has indicated that this reference is not an error, however, the reference method to address opacity monitors (reference method 203) has not been promulgated yet. Therefore, the Division is including the COM calibration requirements in Reg 1, Section IV.F in the permit for the COM QA/QC requirements. It should be noted that ' 75.24(e), which addresses COM out of control periods, also references 40 CFR Part 51, Appendix M. The permit addresses alternate monitoring requirements when the COM is out of control.

Compliance with the Acid Rain requirements are monitored by submitting quarterly data reports and annual compliance certifications to EPA electronically. With each quarterly data report, the source is required to submit a certification to EPA indicating that the monitoring data submitted was recorded in accordance with the applicable requirements. The Division is requiring the source to submit a copy of the quarterly certification that monitoring data has been recorded in accordance with the applicable requirements and the annual compliance certification.

Annual emission calculations, for all pollutants except SO_2 and NO_X, will be required to determine compliance with APEN reporting and for determination of annual emission fees. The CEMs will be used to determine annual emissions of SO_2 and NO_X. In addition, when burning coal, annual performance tests will be required to demonstrate compliance with the PM limitation. Note that depending on the results of the performance test, the frequency of stack testing for PM emissions may be decreased. The source has modeled lead emissions at “worst case” for a one-time only demonstration of compliance. The source shall be required to retain these modeling results and make them available to the Division upon request.

When burning a combination of fuels, the source shall be subject to the most stringent requirements and periodic monitoring. Typically the most stringent periodic monitoring requirements are for coal then natural gas.

4. Compliance Status - The source indicated in the permit application that this unit was out of compliance with NO_X emission limits (Reg 1, Section VII.A.3). The source provided documentation that described the non-compliance and action that had either been taken or was planned to bring the unit into compliance. The source

entered into a Compliance Order on Consent with the Division, signed April 11, 1997. This unit is currently in compliance with all applicable requirements. This Compliance Order did not result in any additional applicable requirements for this emission unit.

B. Unit T001: General Electric Combustion Turbine, Model MS7000, Rated at 570 mmBtu/hr, Serial No. 217803. Natural Gas Fired with No. 2 Fuel Oil Used as Back-Up.

1. Applicable Requirements - This unit was first placed into service and last modified in May 1973. A Apermit to operate@ was issued for this unit. The Apermit to operate@ was issued under Regulation 3 (as adopted December 9, 1971 and effective February 1, 1972) which required that Apermits to operate@ be renewed every 2 years. This permit, P-10,217 on June 15, 1973 and had an expiration date of July 1, 1975.

Although this permit had an expiration date the terms of the permit are still in effect per '25-7-114.(k) C.R.S. which states that Aany permit issued prior to June 20, 1979, with respect to a project or the operation thereof shall continue in full force and effect...@

Although permit P-10,217 does not identify any specific applicable requirements this unit is subject to the following applicable requirements:

- Opacity shall not exceed 20%, except as provided for in Reg 1, Section II.A.4 (Reg 1, Section II.A.1)
- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)
- 0.1 lbs/mmBtu for PM (Reg 1, Section III.A.1.c)
- 0.8 lbs/mmBtu for SO_2 (Reg 1, Section VI.A.3.c.(ii))
- APEN reporting (Reg 3, Part A, Section II)

Because this turbine is a simple combustion turbine (as defined in 40 CFR ' 72.2) that commenced operation before November 15, 1990 it is not an affected unit subject to the Acid Rain Program (40 CFR '72.6(b)(1)).

2. Emission Factors - Emissions from simple cycle combustion turbines are dependent on the fuels being burned. Typically natural gas and No. 2 fuel oil are the primary fuels used. The pollutants of concern are Particulate Matter (PM and PM_{10}), Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_X), Carbon Monoxide (CO) and Volatile Organic Compounds (VOC). Approval of emission factors for this unit is necessary to the extent that acceptable accurate actual emissions are required to verify the need to submit revised APENs to update the Division=s Emission Inventory and for annual fee purposes. The source proposed to use emission factors from EPA=s

Compilation of Emission Factors (AP-42), Section 3.1 (4/00), Table 3.1-1 and 3.1-2a. The emission factors are as follows:

Pollutant	Emission Factor (Natural Gas)	Emission Factor (No. 2 Fuel Oil)
PM	1.9×10^{-3} lbs/mmBtu	4.3×10^{-3} lbs/mmBtu
PM_{10}	1.9×10^{-3} lbs/mmBtu	4.3×10^{-3} lbs/mmBtu
SO_2	0.94S lbs/mmBtu*	1.01S lbs/mmBtu
NO_X	0.320 lbs/mmBtu	0.880 lbs/mmBtu
CO	0.082 lbs/mmBtu	3.3×10^{-3} lbs/mmBtu
VOC	2.1×10^{-3} lbs/mmBtu	4.1×10^{-4} lbs/mmBtu

*If "S" is not available, for natural gas, then an emission factor of 3.4×10^{-3} may be used.

3. Monitoring Plan - Conditions 4.1 through 4.7 identify the monitoring requirements proposed to demonstrate compliance with permit conditions when the turbines are burning natural gas. In the absence of credible evidence to the contrary, compliance with the opacity and particulate matter limitations whenever natural gas is used as fuel. The source indicated that burning of pipeline quality natural gas was sufficient for monitoring compliance with the opacity requirement and the Division agrees. Although the emission factor for SO_2 emissions is dependent on the sulfur content of the fuel, the Division does not believe that the sulfur content of natural gas varies excessively nor is it expected that the sulfur content of the natural gas will exceed 1%, therefore the emission factor for SO_2 will always be less than the Regulation 1 SO_2 requirement. For this reason, the Division also believes that, in the absence of credible evidence to the contrary, compliance with the SO_2 requirement is presumed whenever natural gas is used as fuel

Conditions 5.1 through 5.8 identify the monitoring requirements proposed to demonstrate compliance with permit conditions when the turbines are burning No. 2 fuel oil. The source indicated that burning of No. 2 fuel oil was sufficient for demonstrating compliance with all applicable requirements. Because the AP-42 emission factor for particulate matter is less than the particulate matter standard, in the absence of credible evidence to the contrary, compliance with the particulate matter limitation is presumed whenever No. 2 fuel oil is used as fuel. The source also indicated that fuel oil cannot be purchased with a sulfur content greater than 0.5 weight percent. Based on this sulfur content, the source is in compliance provided the fuel oil has a heat content greater than 88,125 Btu/gallon, this is far below the heat content (140,000 Btu/gallon) identified in AP-42, Appendix A, Page A-5, dated September 1985 (reformatted January 1995). Therefore, the Division will consider, in the absence of credible evidence to the contrary, that the turbines are in compliance with the SO_2 requirements when burning No. 2 fuel oil.

Condition 6.1 identifies the monitoring requirements proposed to demonstrate compliance with permit conditions when the turbines are burning a combination of

natural gas and No. 2 fuel oil. When burning a combination of fuels the source must monitor compliance in accordance with the monitoring plan identified for burning solely No. 2 fuel oil (most stringent).

4. Compliance Status - The source certified that this unit is in compliance with all applicable requirements. Revised APENs were submitted with the Title V application. The Division concurs that this unit is in compliance with all applicable requirements.

C. Unit B002: York and Shiply Boiler, Model AGO, Rated at 25 mmBtu/hr, Serial No. 106W. Natural Gas Fired.

1. Applicable Requirements - This unit was first placed in service in May 1964 and has never been modified. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 25 mmBtu/hr. This maximum can vary somewhat depending on the quality of the fuel used. This unit has a maximum continuous steam flow rating of 225,000 lbs/hr. This maximum steam flow rating cannot be exceeded. Because this boiler is a grandfathered source (in operation prior to February 1972) it is exempt from Colorado Construction Permit requirements. As a grandfathered source this unit has the following applicable requirements:

- Opacity shall not exceed 20%, except as provided for in Reg 1, Section II.A.4 (Reg 1, Section II.A.1)
- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)
- Particulate emissions shall not exceed the following (Reg 1, Section III.A.1.b):

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

  Where: PE = particulate emissions (lbs/mmBtu)
  FI = fuel input (mmBtu/hr)

  At the maximum fuel input rate as specified in the permit application (25 mmBtu/hr), this requirement is calculated as 0.217 lbs/mmBtu. The numerical value will be included in the permit rather than the equation.

- APEN reporting (Reg 3, Part A, Section II)

This unit is not subject to the Acid Rain requirements because it is used for heating and does not generate electricity for sale.

2. Emission Factors - Emissions from this unit are from the combustion of natural gas. The pollutants of concern are Particulate Matter (PM and PM_{10}), Nitrogen Oxides (NO_X), Sulfur Dioxide (SO_2), Carbon Monoxide (CO) and Volatile Organic Compounds (VOC). Negligible quantities of hazardous air pollutants (HAPs) are

produced through the combustion of natural gas. Approval of emission factors for this unit is necessary to the extent that acceptable accurate actual emissions are required to verify the need to submit revised APENs to update the Division=s Emission Inventory and for annual fee purposes. The source proposed in their application to use emission factors from EPA=s Compilation of Air Pollutant Emission Factors (AP-42). It appeared that for all pollutants except NO_X the source used emission factors for large/utility industrial boilers (>100 mmBtu/hr) and it was not clear where the emission factor for NO_X came from. The Division believes these emission factors are not appropriate and therefore is specifying that the source use emission factors from AP-42, dated March 1998, Section 1.4, Tables 1.4-1 and 1.4-2, for small industrial boilers (10-100 mmBtu/hr). The emission factors are as follows:

Pollutant	Emission Factor
PM	1.9 lbs/mmCF
PM_{10}	1.9 lbs/mmCF
SO_2	0.6 lbs/mmCF
NO_X	100 lbs/mmCF
CO	84 lbs/mmCF
VOC	5.5 lbs/mmCF

3. Monitoring Plan - Conditions 7.1 through 7.5 identify the compliance demonstration and monitoring requirements for this unit. Monitoring requirements consist of maintaining records of annual fuel usage and an annual emission calculation. In the absence of credible evidence to the contrary, compliance with the opacity and particulate matter requirements are presumed whenever natural gas is used as fuel.

4. Compliance Status - The source certified that this unit was in compliance with all applicable requirements. Revised APENs were submitted with the permit application. The Division concurs that this unit is in compliance with all applicable requirements.

D. Unit F001: Fugitive Particulate Emissions from Coal Handling and Transportation

E. Unit F002: Fugitive Particulate Emission from Ash Handling and Transportation

F. Unit F003: Fugitive Particulate Emissions from Vehicle Travel on Paved and Unpaved Roads

1. Applicable Requirements - The above sources of fugitive particulate emissions were first placed into service in May of 1964 and have not been modified since. Fugitive particulate emissions from coal handling are generated from the storage and movement (dozing) of coal at the pile and and unloading of coal from rail cars. Fugitive particulate emissions are generated from ash handling (transfer

points) and operation of the ash disposal site. The pertinent applicable requirements for these sources of fugitive particulate emissions are as follows:

- Minimize fugitive particulate emissions (Reg 1, Section III.D.1.a)
- APEN reporting (Reg 3, Part A, Section II)

The 20% opacity, no off-property transport, and nuisance emission limitations identified in Regulation 1, Section III.D.1.c are guidelines not enforceable standards. However, failure to comply with the guidelines may trigger the Division to require the source to submit a fugitive dust control plan. Per Reg 1, Section II.D.1.e.(i)(B) and (C), if a control plan is required, it shall be a permit violation to operate an activity for which a control plan has been disapproved or to fail to comply with the provisions of an approved control plan.

2. Emission Factors - Fugitive emissions are emissions that cannot reasonably pass through a stack, chimney, vent or other functionally-equivalent opening. The presence of outdoor storage and handling of material subjected to wind and mechanical devices results in fugitive emissions. The emissions of interest include particulate matter (PM) which is typically particulates with a relatively coarse size range and particulate matter less than 10 microns in diameter (PM_{10}).

PM and PM_{10} emissions are subject to APEN reporting requirements but are not subject to annual fees. New and revised APENs were submitted with the Title V permit application for these fugitive particulate emission sources. The Division will not require emission calculations for these fugitive emission sources nor specify the emission factors the source must use to calculate emissions. However, these sources are subject to the requirements of APEN reporting and the source must comply with these requirements. The emission factors included in the following section merely identify the emission factors the source has proposed to use for the types of fugitive emission sources identified in their Title V permit.

<u>1. Coal Handling and Transportation</u>

In their Title V permit application the source identified fugitive emission sources as emissions from coal dozers, the storage pile and unloading. After the source had submitted their Title V permit application, it was determined by the source and concurred with by the Division that they had been double counting fugitive emissions from the coal pile by performing a separate calculation for coal dozing. The emission factors the source had proposed (in their Title V permit application) to use for the storage pile, actually take into account emissions from movement and activity at the pile (i.e. coal dozing). Therefore, the source now has proposed to use the following emission factors to estimate emissions from storage and dozing at the pile.

A. <u>Emissions from coal maintenance and storage:</u> The source used emission factors from AP-42 (dated January 1995), Section 11.9, Table 11.9-2. The emission factors used were:

Pollutant	Task	Emission Factor[1]
PM	Storage Pile	1.6μ lbs/acre-hr
PM_{10}	Storage Pile[2]	0.226(1.6μ) lbs/acre-hr

[1] where: μ = wind speed, m/sec
[2] AP-42 did not provide an emission factor for PM_{10} source assumed 22.6 % of PM is PM_{10}

B. Unloading of Coal:

During a site visit at the Valmont facility, the Division observed the rail car unloading operation and concluded that this operation was a source of fugitive emissions. In its Title V permit application, the source used emission factors for drop/transfer points from AP-42 (dated January 1995), Section 13.2.4 to estimate emissions from coal unloading. Emissions were estimated using the following equation:

$$E = \frac{k \times 0.0032 \times (U/5)^{1.3} \times D \times \text{tons of coal transferred per year}}{(M/2)^{1.4}}$$

Where:
E = particulate emissions, lbs/yr
k = particle size multiplier, dimensionless
U = mean wind speed, mph
D = number of transfer points, dimensionless
M = moisture content, %

2. Ash Handling and Transportation

Public Service indicated in their Title V permit application that fugitive emissions from ash handling occur when ash haul trucks are unloaded at an ash disposal site or at some other location that is not enclosed. The Title V permit application indicated that fugitive emissions from ash handling would be estimated using emission factors for drop/transfer points from AP-42 (dated January 1995), Section 13.2.4 (see equation under coal unloading above).

3. Vehicle Travel on Paved and Unpaved Roads

To estimate emissions from travel on unpaved roads, the source proposed to use emission factors from AP-42 (dated January 1, 1995), Section 13.2.2 Unpaved Roads, as follows:

$$E = k \times 5.9 \times (s/12) \times (S/30) \times (W/3)^{0.7} \times (w/4)^{0.5} \times [(365-p)/365] \times VMT$$

where: E = particulate emissions, in lbs/yr
VMT = vehicle miles traveled per year

k = particle size multiplier, dimensionless
s = silt content of road surface material, in %
S = mean vehicle speed, in miles per hour
W = mean weight of vehicle, in tons
w = mean number of wheels
p = number of days with at least 0.01 in. of precipitation per year

In their Title V permit application, the source proposed to estimate emissions from vehicle travel on paved roads using emission factors from AP-42 (dated January 1995), Section 13.2.1 (paved roads). However, after the Title V permit application was submitted, the source was instructed by the Construction Permit Unit to estimate emissions from paved roads, using the emission factors in AP-42 (dated January 1995), Section 13.2.2 (unpaved roads) and a control efficiency of 85%.

3. Monitoring Plan -The source is subject to the APEN reporting requirements for these fugitive emission sources. The Division will not require the source to calculate emissions on any specified frequency; however, the source is responsible for submitting revised APENs as specified by Regulation No. 3, Part A, Section II.C.

These fugitive particulate emission sources are also subject to the requirements of Regulation 1, Section III.D which requires existing sources to employ control measures and operating procedures to minimize fugitive particulate emissions using all available practical methods which are technologically feasible and economically reasonable. These may include, but are not limited to watering or chemical stabilization of unpaved roads; restricting the speed of vehicles; the use of enclosures, covers, compacting and watering of storage piles and during material handling and transportation activities. The source will semi-annually certify that they have complied with the intent of this regulation.

4. Compliance Status - The source certified that they were in compliance with all applicable requirements for coal handling and ash handling. Revised APENs were submitted for these sources with the permit application. The source indicated in its permit application that they were out of compliance with APEN reporting requirements for fugitive particulate emissions generated from vehicle traffic on paved and unpaved roads; however, the source submitted an APEN with its T5 permit application. This source is currently in compliance with the applicable requirements for fugitive particulate emission sources.

G. Unit P001: Ash Silo Equipped with Baghouse and Water Spray

1. Applicable Requirements - The ash silo was first placed into service in June 1993. No construction permit was issued for this unit as the applicable requirements were directly incorporated into the operating permit by processing this unit as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after

the equipment commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification that this unit can comply with the applicable requirements. This unit has the following applicable requirements:

- 20% Opacity (Regulation No. 1, Section II.A.1)

  Based on engineering judgement, the Division has not included the 30% opacity requirement for startup, process modification and adjustment of control equipment (Reg 1, Section II.A.4) for the following reasons: 1) startup is instantaneous (begin loading or unloading); 2) process modifications are unlikely since the process of loading and unloading is straightforward and if modifications were to occur, they could not occur while the unit is in operation (i.e. loading or unloading) and 3) the control equipment cannot be adjusted while loading or unloading is occurring.

- PM emissions not to exceed 5.4 tons/yr (as requested in comments on draft permit received 4/27/01)
- PM_{10} emissions not to exceed 5.4 tons/yr (as requested in comments on draft permit received 4/27/01)
- Fly ash and/or spent sorbent loaded into the silo not to exceed 71,386 tons/yr (as requested in comments on draft permit received 4/27/01)
- Efficiency of Baghouse is 99.9%. When unloading dry ash to an enclosed truck, the combination of the baghouse and the hose connection has an efficiency of 95%. When unloading to an open truck a water spray system is used to control emissions with an efficiency of 90%.

  In initial drafts of the operating permit and the technical review document, requested PM_{10} emissions were 4.3 tons/yr. This was based on the maximum expected throughput of ash as determined by the coal feed design rate of the boiler, the average ash content of the coal and an 80%/20% fly ash/bottom ash split. The 4.3 tons/yr is below the 5 tpy PM_{10} modeling threshold. In 2002, a lime spray dryer system will be installed and operational on the main boiler. The operation of this system will result in the generation of spent sorbent that will be placed in the waste ash silo. In anticipation of the operation of the lime spray dryer system, PSCo has requested that the emission process limits for the ash silo be modified to accommodate the increased throughput that will be expected. The increase in PM_{10} emissions is 1.1 tons/yr, which is below the modeling threshold, therefore no modeling was performed.

  The control method. The efficiency of the water spray was initially determined to be 85% (as indicated in June 18, 1998 correspondence from New Century Energies to the Division), however, after observing the unloading process, the Division determined that the control efficiency of the water spray system could be increased to 90% since the loading process produces very small amounts of fugitive particulate emissions.

Note that no efficiency requirements will be put in the Operating Permit as it is difficult to measure efficiency. However, the source is relying on the efficiency of the control devices to remain below the significance levels (25 tpy PM and 15 tpy PM_{10}) for triggering a major modification that would require major non-attainment area NSR review. In lieu of including control efficiencies in the permit, the source will be required to follow operation and maintenance guidelines to assure that control equipment is functioning properly.

The Division determined that no Regulation No. 1 particulate matter standards were applicable. Operations at the ash silo are not considered fugitive emissions (PM requirements - Reg 1, Section III.D). Although particulate emissions from loading of wet ash into an open truck do not vent through a stack, they exhaust through a functionally equivalent opening and therefore do not meet the definition of fugitive emissions as provided in Regulation No. 3, Part A, Section I.B.25. The Division also does not consider the ash silo to be a manufacturing process (PM requirements - Reg 1, Section III.C) since the ash is a by-product of operating the boiler and no Aproduct@ is made with the ash, nor is it processed further. The purpose of the silo is to store ash until it is removed for sale or disposal.

2. Emission Factors - The source has identified 3 sources of emissions from the ash silo.

The first source is loading ash from the boiler baghouse to the silo. This is performed by a hydro-veyor that conveys ash from the baghouse to the silo, the hydro-veyor creates the vacuum necessary to convey the ash. Ash is separated from the conveying air in a cyclone which collects the ash and allows it to drop into the silo. The conveying air is mixed with water and discharged to the bottom ash pond. Air displaced from the silo during the loading operation is vented though a bin vent baghouse located on the top of the silo.

During unloading into an open truck, the second source of emissions, ash is fluidized in the bottom of the silo by a paddle-like devise. As the ash passes through the fluidizer to the discharge chute, it is continuously wetted with water sprays to control particulate emissions during unloading operations. Permitted emissions are based on emissions from these first two sources of emissions.

The third source of emissions is from unloading ash into an enclosed truck. Dry ash is loaded onto enclosed trucks. For this process a long hose is connected to the enclosed truck. This hose is equipped with an outer exhaust pipe that collects dust from around the inner hose and also pulls air out of the enclosed truck. Air from this exhaust is ducted to the ash silo and eventually passes through the bin vent filter.

Approval of emission factors is necessary to the extent that emission factors shall be used to demonstrate compliance with the annual emission limits. The source proposed using the following emission factors to calculate emissions for the

purposes of demonstrating compliance with the emission limits. Emission factors are from EPA=s Compilation of Emission Factors (AP-42), Section 11.17, dated January 1995. The emission factors are as follows:

Pollutant	EF (lbs/ton)	Source	Assumed Efficiency
PM	0.61	Loading[1]	Baghouse - 99.9%
PM_{10}	0.61	Loading[1]	Baghouse - 99.9%
PM	0.61	Unloading[1]	Combination[2] - 95%
PM_{10}	0.61	Unloading[1]	Combination[2] - 95%
PM	1.5	Unloading[3]	Water Spray - 90%
PM_{10}	1.5	Unloading[3]	Water Spray - 90%

[1]Specifically from Table 11.17-4, Product Unloading - Enclosed Truck
[2] Combination of Ash Silo Baghouse and hose connection
[3]Specifically from Table 11.17-4, Product Unloading - Open Truck

3. Monitoring Plan - Conditions 9.1 through 9.3 identify the compliance demonstration and monitoring requirements for this unit. The source shall be required to calculate the ash throughput monthly, based on the quantity of coal consumed, the average ash content of the coal and a presumed 80/20 fly ash/bottom ash split and to calculate emissions monthly. Based on an engineering analysis, Public Service has indicated that the quantity of additional lime and absorbed SO_2 (the spent sorbent) from the lime spray dryer system are 25%, by weight, of the fly ash produced. In the absence of credible evidence to the contrary, opacity emissions from the ash silo and unloading operations shall be presumed to be in compliance with the opacity requirements provided the control devices are properly maintained and operated.

4. Compliance Status - This unit was previously unpermitted and was not included in the source=s original Title V permit application. The source did submit an APEN for this unit and request that the unit be included in their Operating Permit as a significant emission unit upon discovering that this source had emissions above APEN de minimis. No construction permit was issued for this source as the Operating Permit was nearly complete upon discovery that the silo was not permitted. The applicable requirements were directly incorporated into the operating permit by processing this unit as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. As mentioned previously, the certification by the Responsible Official in the first semi-annual compliance report will serve as the self-certification that this unit can comply with its applicable requirements.

H. Unit P002: Coal Crusher

1. Applicable Requirements - In its Title V permit application, the source had grouped all of its particulate emission sources from coal handling together and identified all sources as fugitive sources. However, some of the sources identified

as fugitive could be reasonably controlled and as a result they are not considered fugitive emission sources. Those activities not associated with the outdoor storage pile (i.e. wind erosion and coal dozing) or rail car unloading have been considered non-fugitive sources. Specifically these sources were coal conveying and the coal crusher. The source indicated in its Title V application that the coal handling operations have been in place since May 1964 and have not been modified since.

Following the source=s original review of the draft operating permit (August - September 1998) and the Division=s decision to consider the unloading of coal from the rail car a source of fugitive particulate emissions, the Division reviewed the source=s emission calculations from coal conveying. The source had used the emission factors for drop/transfer points in AP-42, Section 13.4 (see emission factors identified under II.D.2.A.C of this document) to estimate emissions from coal conveying. With 6 transfer points and using a moisture content of 10% and a wind speed of 5.8 mph (as determined by the Division based on wind data from the Boulder area in 1997) the emissions from coal conveying are estimated at less than 1 tpy for PM and less than 1 tpy for PM_{10}. Therefore, coal conveying can be considered an insignificant activity and the only significant non-fugitive source of emissions from coal handling is the coal crusher.

The coal crusher is grandfathered from construction permit requirements and is subject to the following applicable requirements:

- 20 % opacity (Regulation No. 1, Section II.A.1)

  Based on engineering judgement, the Division has not included the 30% opacity requirement for startup, process modification and adjustment of control equipment (Reg 1, Section II.A.4) for the following reasons: 1) startup is instantaneous (begin crushing); 2) process modifications are unlikely since the process of crushing is straightforward and if modifications were to occur, they could not occur while the unit is in operation (i.e. crushing) and 3) emissions from the crusher are controlled due to their location in a building and so there is no control equipment that could be adjusted or occassionally cleaned and affect opacity emissions.

- APEN reporting (Reg 3, Part A, Section II)

The Division determined that no Regulation No. 1 particulate matter standards were applicable. Coal crushing not considered a source of fugitive emissions (PM requirements - Reg 1, Section III.D) since this source can be reasonably controlled. The Division also does not consider coal crushing to be a manufacturing process (PM requirements - Reg 1, Section III.C) since the coal is not used in manufacturing but is used in fuel burning equipment which has PM requirements in Reg 1, Section III.A.

2. Emission Factors - The source indicated that the non-fugitive emission source

from coal handling was the coal crusher. The Division agrees with this interpretation. Approval of emission factors is necessary to the extent that accurate actual emissions are required to verify the need to submit Revised APENs to update the Division's inventory. The source proposed to use emission factors from EPA's FIRE Version 5.0, Source Classification Codes and Emission Factor Listing for Criteria Air Pollutants (EPA-454/R-95-012), dated August 1995 (SCC 3-05-010-10). The emission factors used were:

Pollutant	Emission Factor
PM	0.02 lbs/ton coal
PM_{10}	0.006 lbs/ton coal

3. Monitoring Requirements - Conditions 10.1 through 10.3 Identify the compliance demonstration and monitoring requirements for these operations. Monitoring requirements shall include maintaining annual records of coal throughput and calculating emissions annually. The coal crusher is housed in a building with no active ventilation system. In the absence of credible evidence to the contrary, the Division will consider the coal crusher to be in compliance with the 20% opacity requirement, provided the integrity of the building is maintained.

4. Compliance Status - An APEN was submitted with the Title V permit application reporting emissions of fugitive particulate emissions from coal handling operations. Both fugitive and non-fugitive sources were included in the APEN. The coal crusher is in compliance with all applicable requirements.

I. Unit M001: Safety-Kleen Cold Cleaner Solvent Vats

1. Applicable Requirements - The solvent vats are subject to work practice standards identified in Regulation 7, Sections X.A (general provisions) and B (work practice/design standards). The source indicated that they have two cold solvent part cleaners. One cleaner meets the requirements of Regulation No. 3, Part A, Section II.D.4.b.(vi) for small remote reservoir cold solvent degreasers and is therefore APEN exempt. The other does not meet the requirements for small remote reservoir degreasers and is subject to APEN reporting requirements if emissions are above APEN de minimis levels. Both types of units are subject to the requirements of Regulation No. 7, Sections X.A and B and have therefore been included in the permit.

2. Emission Factors - The unit that meets the requirements for small remote reservoir degreasers is exempt from APEN reporting requirements. The unit that is not a small remote reservoir degreaser is subject to APEN reporting requirements if emissions are above APEN de minimis levels. The Division will require that annual emissions be calculated for this unit to determine APEN reporting requirements; however, the Division will not specify the emission factors to be used to calculate emissions. The source will need to document the method used to determine

emissions and make that information available to the Division upon request.

3. Monitoring Plan - Because the small remote reservoir unit meets the requirements of Regulation No. 3, Part A, Section II.D.4.b.(vi) this unit is in compliance with the requirements of Regulation No. 7, Section X.B by design. Annual certification by the Responsible Official that this unit has not been modified is adequate to demonstrate compliance with the applicable requirements for this unit. For the unit that is not a small remote reservoir unit, the source indicated that this solvent vat would be operated in accordance with the Public Service Policy manual. The Division accepts this provided the policy manual contains at a minimum the requirements in Regulation 7, Section X.A and B. In addition the Division will require the source to perform an annual audit of either the policy manual or the vat operations to ensure that the policy manual incorporates, at a minimum, the requirements of Regulation No. 7, Section X.B and that operations are being performed within the requirements of the policy manual. The source shall be required to certify annually that waste solvents are being handled appropriately as required by Regulation No. 7, Section X.A.3 and 4.

4. Compliance Status - The source indicated that these units were in compliance with all applicable requirements.

IV. Insignificant Activities:

General categories of insignificant activities include: in-house experimental and laboratory equipment, fuel burning equipment (< 5 mmBtu/hr), chemical storage tanks or containers (< 500 gal), landscaping and site housekeeping devices (< 10 HP), chemical storage areas (< 5,000 gal), storage of butane, propane and LPG (< 60,000 gal), crude/lube oil and condensate storage tanks (< 40,000 gal), fuel dispensing equipment, storage tanks with limited contents (< 400,000 gal), fuel burning equipment, for heating (< 10 mmBtu/hr), internal combustion engines (limited size or hours) and APEN de minimis emission sources.

Specific insignificant activities identified in the Operating Permit application are as follows:

<u>Units/activities with emissions less than APEN de minimis (Reg 3 Part C.II.E.3.a)</u>

Venting of natural gas and leaks
Boiler steam vents
Coal conveyor deicing
Bottom ash handling
Gasoline tank for plant vehicles (500 gal aboveground)
Coal conveying (less than 1 tpy PM and less than 1 tpy PM_{10})

<u>Air conditioning or ventilation systems (Reg 3 Part C.II.E.3.c)</u>

In-house experimental and/or analytical laboratories (Reg 3 Part C.II.E.3.i)

Plant laboratory

Fuel burning equipment less than 5 mmBtu/hr (Reg 3 Part C.II.E.3.k)

propane portable heaters

Chemical storage tanks less than 500 gal (Reg 3 Part C.II.E.3.n)

Unpaved public and private roadways, except haul roads (Reg 3 Part C.II.E.3.o)

Brazing, soldering and welding operations - non-lead based (Reg 3 Part C.II.E.3.r)

Welding machine

Battery recharging areas (Reg 3 Part C.II.E.3.t)

Aerosol can usage (Reg 3 Part C.II.E.3.u)

Spray paint, cleaners and solvent usage

Landscaping/site housekeeping devices less than 10 HP (Reg 3 Part C.II.E.3.bb)

Mowers, snowblowers, etc...

Fugitive emissions from landscaping (Reg 3 Part C.II.E.3.cc)

Emergency events (Reg 3 Part C.II.E.3.ff)

Operations involving acetylene and other flame cutting torches (Reg 3 Part C.II.E.3.kk)

Acetylene welding

Chemical storage areas less than 5,000 gal capacity (Reg 3 Part C.II.E.3.mm)

Oil drum storage area

Architectural painting for maintenance purposes (Reg 3 Part C.II.E.3.nn)

Emissions of air pollutants not criteria or non-criteria reportable (Reg 3 Part C.II.E.3.oo)

Turbine hydrogen vents
Wastewater operations

Janitorial activities and products (Reg 3 Part C.II.E.3.pp)

Groundskeeping activities and products (Reg 3 Part C.II.E.3.qq)

Office emissions (Reg 3 Part C.II.E.3.tt)

Restrooms, copiers, etc...

Storage of butane, propane or LPG in tanks < 60,000 gal (Reg 3 Part C.II.E.3.zz)

Storage of compressed natural gas, butane or propane gas

Storage of lube oil in tanks < 40,000 gal (Reg 3 Part C.II.E.3.aaa)

Miscellaneous lube oil storage tanks

Crude oil or condensate storage tanks < 40,000 gal (Reg 3 Part C.II.E.3.ddd)

Miscellaneous crude oil or condensate storage tanks

Storage tanks with annual throughput < 400,000 gal containing specific contents (Reg 3 Part C.II.E.3.fff)

Emergency generator diesel fuel tank (1,000 gal above ground)
Diesel fuel tank for refueling of heavy equipment (2,000 gal underground)
Turbine lube oil batch tank
Two (2) No. 2 fuel oil tanks for fueling combustion turbine (2.5 million gal each) **– currently empty and out of service**
No. 2 fuel oil tank for fueling combustion turbine (825,000 gal)

Fuel burning equipment < 10 mmBtu/hr used solely for heating (Reg 3 Part C.II.E.3.ggg)

Miscellaneous heaters

Forklifts (Reg 3 Part C.II.E.3.kkk)

Internal combustion engines - limited size, hrs of operation or emissions (Reg 3 Part C.II.E.3.nnn)

Emergency generator (hp < 737 and operates < 250 hrs)

Pesticides, fumigants and herbicides (Reg 3 Part C.II.E.3.ttt)

Ventilation of mobile sources operating within garage, tunnel, or building (Reg 3 Part C.II.E.3.uuu)

Sandblast equipment when blast media is recycled and blasted material collected (Reg 3 Part C.II.E.3.www)

Nonroad Engines - limited hours or size (Reg 3 Part C.II.E.3.xxx(1)(iii))

Water pump (emissions < 5 tpy)

The source also identified mobile engine tailpipe emissions and emissions from a diesel switching locomotive as insignificant activities. Emissions from these sources would not necessarily qualify them as an insignificant activity but they are not applicable to Title V permitting requirements. Therefore, emissions from these sources are not identified in the Operating Permit as insignificant activities.

V. Alternative Operating Scenarios:

A. Alternate Fuels

The primary fuel used for the main boiler (Unit 5) is coal. However, the source requested that this boiler be permitted to use natural gas or a combination of coal and natural gas as a back-up. The primary fuel for the combustion turbine (Unit 6) is natural gas. However, the source requested that this turbine be permitted to use No. 2 fuel oil or a combination of No. 2 fuel oil and natural gas as a back-up.

B. Chemical Cleaning of Boilers

The source has also requested, in a November 15, 1996 submittal (see attached), that boiler chemical cleaning be allowed as an insignificant activity. The Division has previously indicated that this activity does not require permitting. After a boiler has been cleaned the waste cleaning solutions are evaporated in a boiler. In order to be consistent with other power plant Operating Permits and because the Division is placing some requirements on the cleaning events, the chemical cleaning of boilers is being included in the Operating Permit as an alternative operating scenario. A permit (88DE245, initial approval, September 27, 1988) for the temporary evaporation of boiler cleaning solutions was issued for a boiler at Arapahoe Station (see attached). The Division later indicated that no permit was required for this activity and that the source should request that the permit be canceled. Although the permit has been canceled and is no longer valid, it was used as a guide to identify reporting and operating requirements for the alternative operating scenario of evaporating chemical cleaning solutions in the boilers. The only requirement from Permit 88DE245 that was included in the Operating Permit was that any air pollution control equipment shall be operated during evaporation of the cleaning solutions. Permit 88DE245 required that prior notification of the cleaning event, including the amounts and types of cleaning solutions to be evaporated as well as the evaporation rate be provided to the Division. In order to be consistent with the requirement for alternative operating scenarios (Reg 3, Part A, Section IV.A), the Division is requiring that the source maintain records of the date and time the cleaning event starts and ends and the amounts and types of chemicals used in the event. Permit 88DE245 also indicated that the source was subject to the requirements of Regulation No. 8, Sections IV and VI, which limit ambient impacts of mercury and lead. The Division has already included requirements in the Operating Permit for demonstrating compliance with the lead emission requirements in Regulation No. 8, Section IV and therefore does not believe that any further demonstration is required when cleaning the boiler. The

Division no longer has a state standard for mercury and the NESHAP for mercury (40 CFR Part 61, Subpart D) is not applicable to mercury emissions that may occur from coal-fired utility boilers.

VI. Permit Shield:

The source identified and justified a short list of non-applicable requirements that they wish to be specifically shielded from. Based on the information available to the Division and supplied by the applicant, the shield will be granted for the following non-applicable requirements. This shield does not protect the source from any violations that occurred prior to or at the time of permit issuance.

A. Colorado Regulation 6, Part B, Section II (Standards of Performance for New Fuel-Burning Equipment) - This source did not request the shield for this applicable requirement; however, the Division added this one to be consistent with other non-applicable requirements the source identified for this facility. These regulations are not applicable to this facility as the boilers commenced operation prior to January 30, 1979. The permit shield was granted for this reason.

B. 40 CFR Part 60 Subparts D, Da, Db and Dc (as adopted by reference in Colorado Regulation 6) - The permit application states that these New Source Performance Standards (NSPS) requirements are not applicable to the facility as the boilers were constructed before August 17, 1971. The permit shield was granted based on the source=s justification.

Note that although a baghouse were added to the main boiler in 1984 this addition is not considered a modification as it resulted in a decrease in particulate matter emissions. In addition, although low NO_X burners were added to the main boiler in 1990 and modified in 1995, this is not considered a modification as revisions (WEPCO rule, May 20, 1992) made to the federal PSD (40 CFR Part 52.21) and major non-attainment area NSR (40 CFR Part 52.24) requirements, exempted the addition, replacement or use of a pollution control project at an existing electric utility steam generating unit from PSD or major non-attainment area NSR review. The addition of the low NO_X burner is considered a pollution control project.

C. 40 CFR Part 60 Subpart Y (as adopted by reference in Colorado Regulation 6) - The permit application states that these requirements do not apply because this NSPS requirement applies only to coal preparation plants and that while this facility does prepare coal for its own use it is not a coal preparation plant as defined in 40 CFR Part 60, Subpart Y. Although the Division is not convinced that this justification is correct, these requirements are not applicable because the coal handling equipment commenced construction prior to October 24, 1974. The shield was granted for this justification.

During review of the draft permit for this facility, the Division opted to add the permit shield for 40 CFR Part 63, Subpart T (National Emission Standards for Halogenated Solvent Cleaning). These requirements are not applicable because

the solvents used do not contain methylene chloride, perchloroethylene, trichloroethylene, 1,1,1-trichloroethane, carbon tetrachloride, ore chloroform , or any combination in a total concentration greater than 5 percent by weight.

The source requested the permit shield from the Prevention of Significant Deterioration requirements in 40 CFR 52.21 (Colorado Regulation 3, Part B, Section IV.D.3). The source's justification in the permit application states that this requirement is not applicable as the boilers were constructed before and has had no major modifications after August 1, 1977. In comments received on another operating permit, EPA indicated that the Division could not grant the shield for PSD review requirements, unless the source was an existing source prior to August 7, 1977. Although this facility was an existing stationary source prior to August 7, 1977, equipment has been added to the facility after August 7, 1977 and therefore the Division cannot grant the permit shield the PSD review requirements.

The following applicable requirements were streamlined out of the permit and have been included in the permit shield.

<u>Boiler No. 1, Unit B001</u>

- 1.2 lbs/mmBtu SO_2 emission limit when burning coal (Colorado Regulation No. 1, Section VI.A.3.a.(ii)), streamlined out since Colorado Regulation No. 1, Section VII.A.3 SO_2 limit (1.1 lbs/mmBtu) is more stringent.
- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Sections IV.A, B and H), streamlined out since Acid Rain COM/CEM requirements (Part 75) are more stringent. In the case of Reg 1, Section IV.H, the requirement for retention of records is streamlined out since the requirements for retaining records in Reg 3, Part C (general condition 21 in the operating permit) is more stringent.
- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Section VII.A.3), streamlined out since Acid Rain COM/CEM requirements (Part 75) are more stringent.

VII. Acid Rain Provisions:

Boiler No. 5 (identified as unit B001 in the Title V permit application and this document) is an affected unit under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78. Boiler No. 5 has been allocated, on an annual basis, SO_2 allowances (1 ton per year of SO_2) as listed in 40 CFR 73.10(b)(2). The source opted to comply with the Phase I NO_X requirements for Boiler No. 5 which are 0.45 lbs/mmBtu on an annual average basis. Although the Phase I NO_X requirements are in effect now, they are not enforceable by the State until January 1, 2000.

As an affected unit under the Acid Rain Program, Boiler No. 5 must continuously measure and record emissions of SO_2, NO_X (including diluent gas either CO_2 or O_2), and CO_2, as well as volumetric flow and opacity. The source submitted the

continuous emission monitoring (CEM) certification package on January 1, 1995.