TECHNICAL REVIEW DOCUMENT
for
OPERATING PERMIT 96OPDE136
to be issued to:

Public Service Company - Arapahoe Station
Denver County
Source ID 0310008

Prepared October thru November 1999
Revised April 2000, July and August 2001
Jacqueline Joyce, Review Engineer
Revised October 2001 based on comments received During the Public Comment Period and revisions to Colorado Regulation No. 1, which are effective October 1, 2001

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, February 7, 1997, July 6, 1998, February 19, 1999 and December 12, 2000, comments on the draft permit received May 26, 2000 and August 16, 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 four coal-fired boilers. For all units coal is the primary fuel burned with natural gas as a back-up fuel. Unit No. 1 is a 48 MW boiler that is equipped with an electrostatic precipitator to control particulate matter emissions. Unit No. 2 is a 48 MW boiler that is equipped with an electrostatic precipitator and two (2) slip-stream baghouses. To decrease the resistivity of particles entering the electrostatic precipitators for Unit 1, SO_2 gas is injected over a catalyst to oxidize into SO_3 and for Unit 2, elemental sulfur is converted to SO_3 prior to the electrostatic precipitator. Units 1 and 2 share a stack. Unit No. 3 is a 48 MW boiler that is equipped with a baghouse to control particulate matter emissions. Unit No. 4 is a 118 MW boiler that is equipped with a baghouse, low NO_X burners with over-fire air to control NO_X emissions and a dry-scrubber to control SO_2 emissions. Unit No. 4 was also the subject of a urea injection study scheduled to end in 1995. Although the urea injection study has been completed the equipment has not been removed, however, the equipment is out of service. Units 3 and 4 share a stack. Other emission sources at Arapahoe include fugitive emissions from coal handling and storage and from traffic on paved and/or unpaved roads. Note that a permit was issued for an upgrade to the coal handling system in October of 1999 and the new coal unloading facility commenced operation in June 2000. This permit addresses a new rail spur and coal unloading operation at Arapahoe. Finally, Arapahoe station has point source emissions from one (1) ash silo, one (1) coal crusher, the coal conveying system, two (2) sodium reagent silos, three (3) cooling water towers, a diesel air compressor engine and several Safety-Kleen cold cleaners that have applicable requirements and therefore have been included in the Operating Permit.

Note that Public Service Company has entered into a voluntary emission reduction

agreement (hereafter referred to as the "Metro Agreement") with the Division. This agreement will result in the shutdown of Units 1 and 2 in 2003. The requirements of this agreement will be included in the operating permit by reopening the permit or upon renewal, depending upon the issuance date of this permit.

This facility is located in Denver at 2601 South Platte River Drive in Denver county. This facility is located in an area that has been designated as non-attainment for Carbon Monoxide and PM_{10}. As of the issue date of this permit, the State has submitted both CO and PM_{10} attainment/maintenance plans to EPA. If EPA approves the plans, the Denver metro area will be reclassified as attainment/maintenance for CO and PM_{10}. Under that classification, all SIP-approved emission control standards related to CO and PM_{10} will continue to apply.

As of October 11, 2001 the area is classified as attainment for the 1-hour ozone standard. However, all SIP-approved emission control standards related to ozone will continue to apply, including Regulation No. 7 provisions and minor source RACT requirements.

Rocky Mountain National Park and Eagle's Nest National Wilderness Area, both 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) requirements. 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 requirements. For purposes of future PSD or non-attainment area major NSR review, Black Hill's Colorado, LLC combustion turbines (permitted under Colorado Construction Permit 99DE0473) shall be considered in conjunction with this facility. Black Hills Colorado, LLC has submitted an Operating Permit application for this facility and Operating Permit No. 01OPDE237 has been assigned. Although the emissions from the Black Hill's Colorado, LLC combustion turbines 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 these units in accordance with construction permit 99DE0473 is the sole responsibility of Black Hill's Colorado, LLC. Emissions at the facility are as follows:

Pollutant	Potential to Emit (PTE) - 100% Coal[1]	Potential to Emit (PTE) - 100% Natural Gas[2]	Actuals - Combination of Fuels
PM[3]	2,066	1,775	205.8
PM_{10}[4]	1,444	1,752	105.8
SO_2[5]	19,147	19,131	4,166
NO_X[6]	12,443	12,440	3,993
CO	394	695	229.8
VOC	50	34	28.81
Pb[7]	9	Negl.	Negl.
HAPs[8]	110	4.5	14.1

[1]Boilers are firing 100% coal includes emissions from coal and ash handling
[2]Boilers are firing 100% natural gas does not include emissions from coal and ash handling
[3]PTE for boilers, for all fuels, is based on 0.1 lbs/mmBtu x design heat rate x 8760 hrs/yr
[4] PTE for boilers are based on 67% of PM being PM_{10} for coal for units 1 and 2, 92% for coal for units 3 and 4 and 100% for natural gas all units.
[5]PTE for boilers, for all fuels, is based on 1.1 lbs/mmBtu x design heat rate x 8760 hrs/yr.
[6]PTE for boiler 4, for all fuels, is based on 0.60 lbs/mmBtu x design heat rate x 8760 hrs/yr. PTE for boilers 1- 3, for all fuels is based on the Acid Rain NO_X limit x design heat rate x 8760 hrs/yr.
[7] PTE for lead is based on uncontrolled emissions, control efficiency is 97.5% for units 1 and 2 and 99.3% for units 3 and 4.
[8]includes uncontrolled metallic HAPs, control efficiencies range from 78.2 - 99.8 for these compounds

Potential to emit for the boilers 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, haul roads and the cooling towers is based on information supplied in the Title V application for regulated units. Potential to emit for the dry sodium reagent silos, the air compressor engine, the ash storage silo and the new coal unloading station is based on permitted emissions. Actual emissions are based on the Division's 2000 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 2000 inventory (HCl, HF and H_2SO_4).

The source indicated that this facility is subject to 112(r), the Accidental Release Requirements. According to EPA's web page, the risk management plan was submitted for this facility on June 3, 1999 and then revised and submitted on February 7, 2000 to remove the chlorine storage system used to treat the cooling tower circulating water. Risk management plans were due on June 20, 1999.

All four boilers are affected units and are 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: Babcock and Wilcox Top-Fired Boiler, Model and Serial No. NB 16230, Rated at 754.8 mmBtu/hr. Coal-Fired with Natural Gas Used as Back-Up.

1. Applicable Requirements - This unit was first placed in service in October 1950. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 754.8 mmBtu/hr. This maximum can vary somewhat depending on the quality of the fuel used. This unit shares a stack with Unit 2. Both units are equipped with continuous opacity monitors (COMs) and continuous monitors for SO_2 and NO_X emissions and volumetric flow. The COMs for each unit are located in the duct work for that unit, just prior to the common stack. Units 1 and 2 share continuous emission monitors (CEMs) for SO_2 and NO_X and a flow monitor which are located on the common stack.

A Buell Envirotech electrostatic precipitator was installed in January 1977. This installation was not considered a modification as the addition of this equipment did not result in an emissions increase. To decrease resistivity of particulates entering the electrostatic precipitator, SO_2 gas is injected over a catalyst to oxidize into SO_3 prior to the electrostatic precipitator.

A construction permit, C-10,860 was issued for this unit on May 23, 1975, with an expiration date of January 1, 1977. 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 "any permit issued prior to June 20, 1979, with respect to a project or the operation thereof shall continue in full force and effect..." This permit did not identify any specific applicable requirements but only identified the Buell electrostatic precipitator.

Although permit C-10,860 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)
- Particulate Matter emissions shall not exceed 0.1 lbs/mmBtu (Reg 1, Section

III.A.1.c)

- Particulate Matter emissions for combined stacks (Reg 1, Section III.A.1.d)

  The previous language in Reg 1 was confusing regarding determining the applicable emission limit for combined stacks. However, Reg 1 was revised, effective September 30, 2001, and now indicates that the maximum allowable emission rate shall be calculated on a lbs/mmBtu basis as calculated from a weighted average of the individual allowable limits for each unit ducting to the common stack. Under this methodology, the effective standard for the combined stack is as follows:

$$PM = \frac{(754.8 \text{ mmBtu/hr} \times 0.1 \text{ lbs/mmBtu}) + (754.8 \text{ mmBtu/hr} \times 0.1 \text{ lbs/mmBtu})}{(754.8 \text{ mmBtu/hr} + 754.8 \text{ mmBtu/hr})} = 0.1 \text{ lbs/mmBtu}$$

- Continuous emission monitoring requirements (Reg 1, Section IV) as follows:
  - 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 on a 3-hr rolling average, **when firing coal** (Reg 1, Sections VI.A.1 & VI.A.3.a.(ii))
- Emission requirements for certain electric generating facilities which include (Reg 1, Section VII.A.2):
  - SO_2 emissions not to exceed 1.1 lbs/mmBtu, calculated as a 3 hour rolling average (Reg 1, Section VII.A.2.a)
  - Source shall install, certify and operate continuous emission monitoring equipment for measuring opacity, SO_2, NO_X and either CO_2 or O_2 in accordance with 40 CFR Part 60.13 for measuring opacity, SO_2, NO_X and either CO_2 or O_2 (Reg 1, Section VII.A.1.a) (Reg 1, Section VII.A.2.a)
  - Units 1 and 2 shall be permanently retired by January 1, 2003. This requirement shall be come effective upon EPA approval of the designation of the Denver area as a PM_{10} attainment/maintenance area. The requirement to retire these units shall not be construed to prevent the construction or operation of a new source on the site of

such units, provided any such new source complies with all laws and regulation applicable to new sources (Reg 1, Section VII.A.2.c).

- 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 73 to cover emissions for that particular calendar year.
  - Units 1 thru 4 are included in a NO_X averaging plan as allowed by 40 CFR Part 76 § 76.11, as adopted by reference in Colorado Regulation No. 18. The Btu weighted annual NO_X average for the four units must be less than or equal to 0.8 lbs/mmBtu, which is the limitation for vertical-fired boilers in accordance with 40 CFR Part 76 § 76.6(a)(4), as adopted by reference in Colorado Regulation No. 18.
  - Acid rain permitting requirements per 40 CFR Part 72, as adopted by reference in Colorado Regulation No.18.
  - 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 No. 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.2 to have CEMs for opacity, SO_2, NO_X and either CO_2 or O_2. Revisions to Regulation No. 1, Section VII.A.2.a require that the CEMS meet the requirements in 40 CFR Part 60.13. 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 Regulation No. 1, Sections A & B will be streamlined out in favor of the Acid Rain CEM requirements as they are more stringent. Although recent revisions to Regulation No. 1, Section VII.A.2.a effectively specify that the monitors

shall meet NSPS requirement (40 CFR Part 60), as allowed by the EPA (see attached), the requirement in Regulation No. 1, Section VII.A.2.a will be streamlined out of the permit in favor of the more stringent Part 75 requirements. However, for reasons discussed below, the COM will be subject to QA/AC requirement in Regulation No. 1, Section VII.A.2.a (40 CFR Part 60.13). 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) rather than the Regulation No. 1, Section VII.A.2.a requirements (40 CFR Part 60 Appendix B, as referenced in 40 CFR Part 60.13(a)) as the Part 75 requirements are for the most part more stringent. Note that Part 75 identifies the COM performance specifications as 40 CFR Part 60, Appendix B, Spec 1, which is the same as the COM performance specification requirements in Regulation No. 1, Section VII.A.2.a. It should be noted that the Regulation No. 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 Regulation No. 1, Section IV does not identify specific QA/QC requirements and the QA QC requirement in Regulation NO. 1, Section VII.A.2.a (40 CFR Part 60.13) are less stringent than the QA/QC requirement in Part 75. 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 requirements in Regulation No. 1, Section VII.A.2.a (40 CFR Part 60.13) will be included in the permit to identify the QA/QC requirements for the COM. A review of 40 CFR Part 60.13 indicates that only 40 CFR Part 60.13(d) would apply to the COM as a QA/QC requirement. The remaining requirements in 40 CFR Part 60.13 are either applicable to the CEM or are addressed in 40 CFR Part 75. The calibration requirements in Regulation No. 1, Section IV.F will be streamlined out of the permit since the QA/QC requirement in 40 CFR Part 60.13(d) are more stringent.

The excess emissions notification and recordkeeping requirements from Regulation No. 1, Section IV.G have been included in the Operating Permit. Note that the record retention in Regulation No. 1, Section IV.H (maintain records for 2 years) is less stringent than the Regulation No. 3, Part C recordkeeping requirements therefore, the Regulation No. 1, Section IV.H record retention requirement will be streamlined out of the permit in favor of the Regulation No. 3, Part C requirements (General Condition No. 21b & 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 averaging time if not

otherwise specified in the regulation). The Regulation No. 1, Section VII.A.2 standards are 1.1 lbs/mmBtu calculated as a 3-hour rolling average. Since the Regulation No. 1, Section VII.A.2 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 SO_2 requirements and the Regulation No. 1, Section VII.A.2 SO_2 standard. Note that the Acid Rain SO_2 allowances appear only 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 consumption - Section 1.1 (9/98), Tables 1.1-3, 1.1-4, 1.1-6 and 1.1-19 for pre-NSPS wall-fired boilers burning bituminus coal and for natural gas - Section 1.4 (3/98), Tables 1.4-1 and 1.4-2 for wall-fired boilers.

The proposed emission factors are as follows:

Pollutant	Emission Factor[1] (Coal)	Emission Factor (Natural Gas)
PM	10A lbs/ton	1.9 lbs/mmCF
PM_{10}	0.67(PM)	1.9 lbs/mmCF
SO_2	CEM	CEM
NO_X	CEM	CEM

CO	0.5 lbs/ton	84 lbs/mmCF
VOC	0.06 lbs/ton	5.5 lbs/mmCF

[1]A = weight percent ash in coal

Lead emissions shall be calculated as follows:

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

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

Note that 10A is the AP-42 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, and to monitor compliance with the emission limitations.

This boiler is equipped with a electrostatic precipitator to control particulate emissions. Provided the source maintains the electrostatic precipitator per manufacturer's recommendations and good engineering practices, a 99.03% efficiency can be applied to the PM and PM_{10} emission factors when burning natural gas. A control efficiency of 97.5% can be applied to the lead (Pb) emission factor when burning coal.

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 1.13 address coal burning and 2.1 through 2.12 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 and SO_2 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 requirements in Reg 1, Section VI.A.2.a (40 CFR Part 60.13, specifically 60.13(d)) 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 provides/requires 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 permit requires that a copy of the annual compliance certification be sent to the Division.

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. Typically for coal-fired utility boilers, the Division is requiring annual stack tests to monitor compliance with the particulate matter limitations. However, when since the Metro Agreement will result in the shutdown of this unit prior to January 1, 2003, no stack testing will be required for this unit. 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. The most stringent periodic monitoring requirements are for coal-firing of the unit.

4. Compliance Status - The source indicated in their permit application that this unit was in compliance with all applicable requirements. The Division concurs with this determination.

B. Unit B002: Babcock and Wilcox Top-Fired Boiler, Model and Serial No. RB 16231, Rated at 754.8 mmBtu/hr. Coal Fired with Natural Gas Used as Back-Up.

1. Applicable Requirements - This unit was first placed in service in March 1951. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 754.8 mmBtu/hr. This maximum can vary somewhat depending on the quality of the fuel used. As discussed for Unit 1,

this unit shares a stack with Unit 1.

A UOP Air Correction electrostatic precipitator was added in 1968. This addition to the boiler did not constitute a modification because no increase in emissions occurred. To decrease resistivity of the particulates in the electrostatic precipitator, elemental sulfur is burned and converted to SO_3 prior to the electrostatic precipitator. In addition, slip-stream baghouses were added to this unit in 1997. These are horizontal units and pull about 30% of the gas stream from the inlet duct to the electrostatic precipitator. This addition did not constitute a modification because no increase in emissions occurred. It should be noted that there are particulate monitors installed on the inlet and outlet of each slipstream baghouse and the inlet and stack of all control equipment. The slipstream baghouse particulate monitors are not certified compliance monitoring systems and are only used for trouble shooting and operation of the baghouse particulate control system.

This boiler can be considered a "grandfathered" source and therefore is exempt from Colorado Construction Permit requirements because this unit was in service prior to and based on the information available to the Division and supplied by the applicant has not been modified after February 1, 1972. As a grandfathered unit, this boiler has the same applicable requirements as Unit 1.

Streamlining of Applicable Requirements

Continuous Emission Monitors

See streamlining of continuous emission monitoring requirements discussion for Unit No. 1.

Sulfur Dioxide (SO_2)

See streamlining of SO_2 requirements discussion for Unit No. 1.

2. Emission Factors - See discussion for Boiler No. 1 emission factors. Note that a control efficiency of 97.92% can be applied if the electrostatic precipitator and slip-stream baghouses are operated and maintained in accordance with manufacturer's recommendations and good engineering practices for PM and PM_{10} emissions when burning natural gas.

3. Monitoring Plan - See discussion for Boiler No. 1 monitoring plan.

4. Compliance Status - The source indicated in their permit application that this unit was in compliance with all applicable requirements. The Division concurs with this determination.

C. Unit B003: Babcock and Wilcox Front-Fired Boiler, Model and Serial No. RB

16911, Rated at 754.8 mmBtu/hr. Coal Fired with Natural Gas Used as Back-Up.

1. Applicable Requirements - This unit was first placed in service in November 1951. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 754.8 mmBtu/hr. This maximum can vary somewhat depending on the quality of the fuel used. This unit shares a stack with Unit 4. Both Units 3 and 4 have COMs and CEMs located in the ductwork prior to the stack.

A Joy fabric filter baghouse was added in 1978. This addition to the boiler did not constitute a modification because no increase in emissions occurred.

This boiler can be considered a "grandfathered" source and therefore is exempt from Colorado Construction Permit requirements because this unit was in service prior to and based on the information available to the Division and supplied by the applicant has not been modified since February 1, 1972. As a grandfathered unit, this boiler has the same applicable requirements as Unit No 1.

Streamlining of Applicable Requirements

Continuous Emission Monitors

See streamlining of continuous emission monitors discussion for Unit No. 1.

Sulfur Dioxide (SO_2)

See streamlining of SO_2 requirements discussion for Unit No. 1.

2. Emission Factors - See discussion for Boiler No. 1 emission factors, except that the emission factor used for PM shall be based on the results of the required performance testing. In addition, since this unit is equipped with a baghouse, the percent of PM that is PM_{10} is 92% rather than 67%. Note that this unit has a fabric filter baghouse to control particulate matter emissions and a control efficiency of 99.9% can be applied to the emission factors for PM and PM_{10} when burning natural gas. An efficiency of 99.3% can be applied to the lead (Pb) emission factor when burning coal.

3. Monitoring Plan - See discussion for Boiler No. 1 monitoring plan.

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.

4. Compliance Status - The source indicated in their permit application that this unit was in compliance with all applicable requirements. The Division concurs with this determination.

D. Unit B004: Babcock and Wilcox, Top-Fired Boiler, Model and Serial No. HSB 18469, Rated at 1,709.4 mmBtu/hr. Coal Fired with Natural Gas Used as Back-Up.

1. Applicable Requirements - This unit was first placed in service in August 1955. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 1,709.4 mmBtu/hr. This maximum can vary somewhat depending on the quality of the fuel used. As discussed for Unit No. 3, this unit shares a stack with Unit 3. Unit 4 in addition to the CEM discussed under Unit No. 3 has a CEM to measure SO_2 emissions at the inlet of the dry sodium injection system. The inlet CEM is not a certified compliance monitoring system and is used only for trouble shooting and operation of the dry sodium injection system.

A Ecolaire fabric filter baghouse was installed in 1984. A dry sodium injection system was installed in May 1992 to control SO_2 emissions. These additions do not constitute modifications because no increase in emissions occurred.

In May 1992, low NO_X burners with overfire air were added to Unit 4. 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 "...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 purposes of Title I, if any, <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 PSD or major 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 (Colorado Regulation No. 6, Part B) NSPS

requirements. The Division believes that emissions of CO may be increased by the addition of the low NO_X burners but 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 low NO_X burners were installed 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.

The Division's inventory system identifies that Unit 4 was issued a "permit to operate", permit P-10,689. Neither the Division, nor the source, have been able to locate a copy of this permit. Typically the permits issued with these types of permit numbers did not include applicable requirements, but only identified the subject equipment or control device. Unit No. 4, is a grandfathered unit and as such is subject to the same applicable requirements as Unit No. 1, with the following additional requirements:

- Emission requirements for certain electric generating facilities which include (Reg 1, Section VII.A.2):
  - SO_2 emissions shall not exceed 1.1 lbs/mmBtu and 20% annual reduction (Reg 1, Section VII.A.2.a)
  - NO_X emissions not to exceed 0.60 lbs/mmBtu, calculated on a 30 day rolling average (Reg 1, Section VII.A.2.a)
  - The 20% SO_2 reduction requirement shall be calculated on a calendar year, total annual tonnage basis.

    Note that Reg 1, Section VII.A.2 included requirements to operate the SO_2 removal equipment during certain times of the year and to report if the unit was not operating for a period of 24 hours or more during that time. However, Reg 1 was revised, with the revisions becoming effective on September 30, 2001. The revised Reg 1 no longer includes such requirements to operation the SO_2 removal equipment during certain periods and to report when the SO_2 removal equipment is not operating.

  - Upon EPA approval of the designation of the Denver area as a PM_{10} attainment/maintenance area, the SO_2 emission rate shall not exceed 0.88 lbs/mmBtu, calculated on a 30-day rolling average. Such emissions limitation shall apply seasonally from November 1 through

March 1 (Reg 1, Section VII.A.2.b).

Streamlining of Applicable Requirements

Continuous Emission Monitors

See streamlining of continuous emission monitors discussion for Unit 1.

Sulfur Dioxide (SO_2)

See streamlining of SO_2 requirements discussion for Unit 1.

In addition, this unit is subject to a requirement to reduce annual (calendar year) emissions of SO_2 by 20% (Reg 1, Section VII.A.2). Since this limitation cannot be compared with the Reg 1 requirements for stringency, this limitation cannot be streamlined out of the permit.

Note that upon EPA's approval of the designation of the Denver area as a PM_{10} attainment/maintenance area, Unit 4 will be subject to an SO_2 emission limitation of 0.88 lbs/mmBtu (Regulation No. 1, Section VII.A.2.b). Although this SO_2 limitation is less than the Regulation No. 1, Section VII.A.2.a limitation of 1.1 lbs/mmBtu, neither requirement can be streamlined out of the permit, since the averaging times are different and the 0.88 lbs/mmBtu requirement does not apply on a year round basis.

Nitrogen Oxides (NO_X)

This source is subject to both the Regulation No. 1, Section VII.A.2 standards and the Acid Rain NO_X requirements. The Acid Rain NO_X requirement is 0.80 lbs/mmBtu based on a calendar annual average. The Regulation No. 1, Section VII.A.2 standard is 0.60 lbs/mmBtu, based on a 30-day rolling average. Although the Regulation No. 1, Section VII.A.2 standard appears to be more stringent, 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.2 requirements. Note that the Acid Rain NO_X limitations only appear in Section III (Acid Rain Requirements) of the permit.

2. Emission Factors - See discussion for Boiler No. 1 emission factors, except that the emission factor used for PM shall be based on the results of the required performance testing. In addition, since this unit is equipped with a baghouse, the percent of PM that is PM_{10} is 92% rather than 67%. Note that this unit has a fabric filter baghouse to control particulate matter emissions and a control efficiency of 99.9% can be applied to the emission factors for PM and PM_{10} when burning

natural gas. An efficiency of 99.3% can be applied to the lead (Pb) emission factor when burning coal.

Unit 4 is subject to a 20% SO_2 reduction requirement, on a calendar year, total annual tonnage basis.

The percent reduction will be determined using coal sampling for the inlet SO_2 emission rate and the continuous emission monitor will be used to determine the outlet SO_2 emission rate. The following methodology will be used to determine the percent emission reduction:

$$\text{Red.} = 100\% \times \frac{[\text{Annual inlet } SO_2 \text{ emission rate (lbs/mmBtu)} - \text{Annual outlet } SO_2 \text{ emission rate (lbs/mmBtu)}]}{\text{Annual inlet } SO_2 \text{ emission rate (lbs/mmBtu)}}$$

Note that: inlet = uncontrolled
outlet = controlled

INLET SO_2 CALCULATIONS

$$\text{Monthly } SO_2 \text{ emission rate} = \frac{(10^6 \text{ Btu/mmBtu}) \times (64 \text{ lbs } SO_2/32 \text{ lbsS}) \times \text{avg. S content of coal (lbs S/lb coal)}}{\text{avg heat content of coal (Btu/lb coal)}}$$

Monthly SO_2 emissions = Monthly SO_2 emission rate x Monthly coal heat input x 1 ton/2000 lbs

Annual SO_2 emissions = Sum of monthly SO_2 emissions

$$\text{Annual } SO_2 \text{ emission rate} = \frac{\text{Annual } SO_2 \text{ emissions (tons/yr)} \times 2000 \text{ lbs/1 ton}}{\text{Annual heat input, coal (mmBtu/yr)}}$$

HEAT INPUT CALCULATIONS

$$\text{Monthly heat input, coal} = \frac{\text{coal burned (tons/mo)} \times \text{avg heat content of coal (Btu/lb)} \times 2000 \text{ lbs/ton}}{10^6 \text{ Btu/mmBtu}}$$

Annual heat input, coal = Sum of monthly heat input, coal

Annual heat input, gas = gas burned (mmSCF/yr) x heat content of gas (mmBtu/mmSCF)

OUTLET SO_2 CALCULATIONS

$$\text{Annual } SO_2 \text{ emission rate} = \frac{SO_2 \text{ emissions from CEMS (tons/yr)} \times 2000 \text{ lbs/ton}}{\text{Heat input, coal (mmBtu/yr)} + \text{Heat input, gas (mmBtu/yr)}}$$

Note that the above method to calculate the percent reduction is intended to follow the methodology in the Metro Agreement. However, one clarification and one change were made regarding the Metro Agreement Methodology. The Metro Agreement specifies that "the unit total monthly tons of coal will be matched, as nearly as possible, with the heat content (measured in Btus per pound) determined from the unit train coal sample analysis". It is the Division's impression that for each train load of coal, the vendor provides an analysis of the heat and sulfur content of the coal in that train load. The Division is also under the impression that Public

Service may receive several train loads of coal each month. Therefore, it is not clear how coal burned in any unit can be tied to any one coal train analysis. Therefore, the Division is requiring that the average heat and sulfur content of coal be used in the above calculations. All vendor analyses will be used to determine the average values to be used in the above calculations.

In addition, the Metro Agreement requires that the heat input from natural gas be determined monthly and the Metro Agreement does not specify that sampling is required to determine the heating value of the natural gas. The permit shall be written to allow the source to use an annual average heating value for the natural gas and therefore it seems unnecessary to require monthly calculations of the heat input from natural gas. Therefore, the Division will only require that the source determine the heat input from natural gas on an annual basis.

Note that if the SO_2 reduction is calculated to be 35% or less, then the inlet SO_2 emission rate shall be determined, using the emission factor from AP-42, Section 1.1, Table 1.1-3 (wall-fired, pre-NSPS boilers burning bituminous coal) as follows:

$$\text{Inlet } SO_2 \text{ emission rate} = \frac{35 \text{ (lbs } SO_2\text{/ton) x avg. wt percent sulfur in coal x } 10^6 \text{ Btu/mmBtu}}{\text{Avg. heat content coal (Btu/lb) x 2000 lbs/ton}}$$

Note that as indicated in the methodology for the Metro Agreement, the above inlet SO_2 emission rate shall be calculated monthly using the average sulfur and heat content of the coal received that month. All vendor analyses will be used to determine the average values to be used in the above calculations. The above monthly inlet SO_2 emission rate will then be used to calculate the percent reduction as specified in the Metro Agreement.

3. Monitoring Plan - See discussion for Boiler No. 1 monitoring plan.

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.

Also, note that Unit 4 does have an SO_2 reduction requirement. Although, this unit is equipped with a CEM, to measure the inlet sulfur concentration, the data acquisition and handling system for this unit is not very sophisticated and is not Y2K compliant, as the source never expected this CEM to be used to monitor compliance with the percent reduction requirement. In order to use the inlet SO_2 CEM, upgrades would have to be made to the data acquisition and handling system. The 20% reduction requirement is from Reg 1, Section VII.A.2.a and does not specify how compliance with the reduction requirement shall be monitored. Nor does Reg 1, Section VII.A.2 require that an inlet SO_2 continuous emission monitor be installed and operated.

The Division and Public Service Co entered into a voluntary emission reduction agreement that is applicable to Denver Metro area power plants. This agreement, which takes effect on January 1, 2003, requires that SO_2 emissions from the Arapahoe, Valmont and Cherokee facilities not exceed 10,500 tons/yr or SO_2 emissions shall be reduced by 70%. Public Service Co believes and the Division concurs, that once the Metro Agreement becomes applicable, that SO_2 reductions from Arapahoe 4 will far exceed 20%. Compliance with the 70% reduction requirement in the Metro Agreement is monitored by using coal sampling data to determine the inlet SO_2 concentration.

Since the Division believes that with the Metro Agreement, the SO_2 reduction will far exceed the 20% limitation, the Division will allow PSCo to determine inlet SO_2 emissions using coal sampling and the methodology discussed under the emission factors. The outlet SO_2 concentration will be based on the outlet SO_2 CEM. The annual percent reduction will be calculated as discussed under emission factors.

The 20% SO_2 reduction requirement was applied to a unit that burns coal as its primary fuel. Therefore, in the absence of credible evidence to the contrary, when burning natural gas, this unit will be presumed to be in compliance with the 20% SO_2 reduction requirement. Note however, that when burning natural gas, the permit will require that the heat input to the boiler from natural gas shall be calculated annually and used in the calculations to monitor compliance with the 20% reduction requirement.

4. Compliance Status - The source indicated in their permit application that this unit was in compliance with all applicable requirements. The Division concurs with this determination.

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

F. Unit F002: 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 1950. Based on the information available to the Division and supplied by the applicant, these sources have not been modified since then. Therefore these fugitive emission sources are grandfathered from construction permit requirements. Fugitive particulate emissions from coal handling are generated from storage and movement (dozing) of coal at the pile and unloading of coal from rail cars.

In their February 7, 1997 additional information submittal, the source indicated that there were alternative operating scenarios for coal handling and ash handling. For coal handling, the alternative operating scenario would be that coal would be transported to the facility and unloaded via truck rather than rail. The source

indicated that this scenario only affected and increased emissions from traffic on paved and unpaved roads. The Division does not consider this a true alternative operating scenario as coal unloading, except for the new rail car unloading station and associated conveyors, is grandfathered from construction permit requirements and therefore there are no requirements that coal be unloaded only from rail car. In addition, the emissions from the paved and unpaved roads, are grandfathered from construction permit requirements. Therefore, the alternative operating scenario is not specifically included in the operating permit, however, there is nothing in the operating permit that prohibits the source from receiving and unloading coal at this facility by truck.

The alternative operating scenario identified for ash handling is that ash may be transported onsite to a vendor-operated secondary product processing unit. A secondary product processing unit may require permitting, even if vendor-operated and this scenario would need to be reviewed further to determine permitting requirements. Therefore, the Division requested information from the source on the vendor-operated secondary product processing unit and was informed that there was no such ash processing operation. As a result, this alternative operating scenario was not included in the operating permit. Note that the ash handling addressed in this potential alternative operating scenario would most likely not be considered a source of fugitive emission but would be considered point source (non-fugitive) emissions.

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 application.

1. Coal Handling and Transportation

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. Emissions from coal pile maintenance and storage: 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]	$0.23(1.6\mu)$ lbs/acre-hr

[1] where: μ = wind speed, m/sec
[2] AP-42 did not provide an emission factor for PM_{10} source assumed 23 % of PM is PM_{10}

B. Unloading of Coal: 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. 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 No. 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. 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 APENs with its T5 permit application. This source is currently in compliance with the applicable requirements for fugitive particulate emission sources.

G. Unit F003/P004: New Rail Car Unloading Station

1. Applicable Requirements - This emission unit was not included in the original Title V permit application. In 1999, the source applied for a construction permit application for a new railcar unloading station at this facility and the new unloading station commenced operation in June 2000. The new railcar unloading station includes conveyors that move coal from the unloading hoppers to the storage pile. Included is a small reclaim conveyor that connects the pile to the existing unloading hoppers. The Division issued construction permit 99DE0120, initial approval, dated October 6, 1999 for this emission unit and this unit. 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.

The applicable requirements as identified in permit 99DE0120 are as follows:

- Opacity of emissions shall not exceed 20%, except as provided for below. During periods of startup, process modification or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (Reg 1, Section II.A.4). Opacity shall be measured by EPA Method 9 (condition 1).

  Note that the 20% and 30% opacity requirements apply to point source emissions and not fugitive emissions. The new rail car unloading station and associated conveyors are a combination of fugitive and point source emissions. Actual unloading of the coal from the rail car is considered a source of fugitive emissions. Conveying of the coal is considered a point source, as these emissions can be reasonably enclosed. Therefore, the 20% and 30% opacity requirements apply only to the conveying of coal.

  The 30% opacity applies during startup, process modifications and adjustment of control equipment. Based on engineering judgement, the conveyors are considered to be in normal operation when they are turned on (i.e. startup is instantaneous) and no modifications can be made to the conveying process while they are being operated. The control equipment for conveying is enclosures and as such cannot be adjusted. Therefore, the

30% opacity requirement will not be included in the permit as the specific operational activities under which the requirement applies are not applicable to this emission unit.

- Construction of this source must commence within 18 months of initial approval permit issuance date or within 18 months of date on which such construction or activity was scheduled to commence as stated in the application. If commencement does not occur within the stated time the permit will expire on April 16, 2001 (condition 3).

  This unit has commenced operation (startup notice submitted March 2, 2000, projected startup in the notice was mid-May 2000 with and operation at full capacity began in June 2000) and therefore, this requirement will not be included in the operating permit.

- Emissions of air pollutants shall not exceed the following limitations (condition 4):
  PM 6.1 tons/yr
  PM_{10} 2.9 tons/yr
  Compliance with the annual limits shall be determined on a rolling 12 month total.
- Processing rate is limited as follows (condition 5):
  Unloading of coal 1,568,040 tons/yr
  Compliance with the yearly processing limits shall be determined on a rolling 12 month total.
- The following control measures shall apply (conditions 6 thru 9):
  - unloading hoppers shall use water spray if material moisture content is insufficient to control particulate emissions.
  - all conveyors and transfer points shall be enclosed.
  - drop to coal pile shall be equipped with a telescopic chute.
- This emission unit is subject to the requirements of 40 CFR Part 60 Subpart Y, as adopted by reference in Colorado Regulation No. 6, Part A (New Source Performance Standards (NSPS) for Coal Preparation Plants). Specifically, emissions from conveyors, transfer points and loading systems that convey coal to the plant processing equipment shall be less than 20% opacity (condition 11).

  The actual unloading of coal for this unloading facility is not subject to the requirements of 40 CFR Part 60, Subpart Y, since the coal is not unloaded directly to coal processing plant machinery (i.e. hopper or a conveyor to a hopper or crusher) but is unloaded to a storage pile. However, since the reclaim conveyer takes coal from the pile to the original unloading hoppers and subsequently is conveyed from the original unloading hoppers to the crusher, the reclaim conveyor is subject to the requirements of NSPS Subpart Y.

- In addition, the requirements in 40 CFR Part 60 Subpart A, as adopted by reference in Colorado Regulation No. 6, Part A (NSPS General Provisions). Specifically identified are:
  - good practices (40 CFR Part 60 Subpart A § 60.11(d))
  - circumvention (40 CFR Part 60 Subpart A § 60.12)
  - Notification of construction and initial startup (40 CFR Part 60 Subpart A § 60.7(a))

    Note that since this unit commenced operation (startup notice submitted March 2, 2000 and operation at full capacity began June 2000) that these requirements will not be included in the operating permit.

  - Maintain records of startups, shutdowns and malfunctions (40 CFR Part 60 Subpart A § 60.7(b))
  - Initial performance test (40 CFR Part 60 Subpart A § 60.8) Note that this requirement was not included in the construction permit.

    Note that the performance test was conducted on November 15 and 16, 2000. Therefore, the requirement to conduct an initial performance test will not be included in the permit.

Streamlining of Applicable Requirements

Opacity

The reclaim conveyor is subject to a Reg 1 20% opacity requirement (not to exceed 20%) and an NSPS opacity requirement of less than 20%. The Reg 1 opacity requirement applies at all times except for the specific operating activities where the 30% opacity requirement applies. However, the Division determined that the specific activities under which the 30% opacity requirement applies are not applicable to the reclaim conveyor, so the Reg 1 20% opacity requirement applies at all times. The NSPS opacity requirement applies at all times except for startup, shutdown and malfunction. Therefore, since neither opacity requirement is more stringent at all times, both opacity requirements will remain in the permit.

2. Emission Factors - Approval of emission factors is necessary to monitor compliance with the emission limits for the railcar unloading station. There are no specific emission factors for conveying coal. Therefore, the source proposed to estimate emissions from coal conveying as emissions from each of the drop or transfer points. The emission factors for transfer points were also used to estimate emissions from the actual unloading of coal from the railcar. The Division believes that this is a reasonable method to estimate emissions from coal conveying and unloading.

Emissions from unloading is considered a source of fugitive emissions and is therefore subject to APEN reporting requirements but not subject to payment of annual emission fees. Emissions from the conveying of coal are considered point source emissions and are therefore subject to the APEN reporting requirements and payment of annual fees.

The source proposed to use emission factors for drop/transfer points from AP-42 (dated January 1995), Section 13.2.4, which is discussed in the previous section regarding emission factors for coal unloading.

Note that the permitted emissions were based on 5 transfer points, a moisture content of 4.5% (from AP-42, Section 13.2, Table 13.2.4-1, average moisture content for coal received at coal-fired power plants) and a wind speed of 8.7 mph. When estimating actual emissions, the actual moisture content of the coal, as determined by sampling, may be used. In addition, for any covered transfer point, a lower wind speed may be used to estimate actual emissions.

3. Monitoring Plan - Monitoring for the new railcar unloading facility will consist of recording the quantity of coal unloaded and calculating emissions monthly. The control measures for the coal unloading will be followed to minimize fugitive emissions. Compliance with the opacity requirements for all conveyors shall be presumed, in the absence of credible evidence to the contrary, provided the conveyors are covered and water suppression is used as necessary.

4. Compliance Status - The new railcar unloading facility was not included in the original Title V permit application. The source submitted an APEN and obtained a construction permit prior to beginning construction on the new unloading station. 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 P001: Ash Silo Equipped with a Baghouse

1. Applicable Requirements - In its Title V permit application, the source had grouped all of its particulate emission sources from ash handling together and identified all sources as fugitive sources. However, not all emissions from ash handling are fugitive. The ash collection system for all units initially consisted of combining the dry ash from the control equipment with water and sluicing the ash slurry out to the ash pond directly. The wet ash unloading system for Units 1 thru 3 are not a source of emissions and therefore are not addressed in the operating permit. When the dry scrubber was added to Unit 4, ash could no longer be sent to the ash ponds. During this time, an ash silo was installed so that dry ash could be unloaded from the Unit 4 baghouse into the silo. The loading and unloading of the ash silo is considered a point source and as such is subject to emission fees. Note

that there are no ash handling activities at this facility that are considered fugitive emissions.

The silo was placed in service in May 1992 . No construction permit was previously issued for this unit, however, the applicable requirements were directly incorporated into the operating permit by processing this unit as a combined construction/operating permit. 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.

In their comments on the draft permit, received on August 16, 2001, the source indicated that in order to comply with the upcoming Metro Agreement, that a dry sodium injection system will be installed on Unit 3. Because of the spent sorbent that will be present in the ash when the dry sodium injection system is operational, the ash can no longer be disposed of in the ash ponds and will need to be handled dry through the ash silo. Therefore, the source has requested increased emissions for the ash silo to accommodate the unit 3 ash beginning in 2003.

The ash silo (P001) 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.

- APEN reporting (Regulation No. 3, Part A, Section II)
- PM emissions not to exceed 4.6 tpy (based on maximum quantity of ash processed per October 22, 1999 and July 10, 2001 e-mails from source and AP-42 emission factors)
- PM_{10} emissions not to exceed 4.6 tpy (based on maximum quantity of ash processed per October 22, 1999 and July 10, 2001 e-mails from source and AP-42 emission factors)

  Note that, as requested in their comments on the draft permit (received August 16, 2001) emissions were increased to 6.7 tons/yr to accommodate the future emissions from Unit 3 ash being processed through the silo. This silo should have been permitted prior to installation (1992) but was

overlooked by the source and the Division. At the time the silo would have been permitted to only include emissions from the processing of ash from Unit 4, which has estimated emissions of 4.6 tons/yr. No modeling would have been required for this permit, since the emissions of PM_{10} were below the 5 tpy modeling threshold level in the Division's Modeling Guidance. The increase in emissions from the processing of Unit 3 ash is 2.1 tons/yr and is below the PM_{10} modeling threshold of 5 tpy, therefore emissions from the ash silo were not modeled.

- Fly ash handling not to exceed 60,906 tpy (as requested in October 22, 1999 and July 10, 2001 e-mails from source)

  Note that, as requested in their comments on the draft permit (received August 16, 2001) throughput was increased to 88,307 tons/yr to accommodate the future emissions from Unit 3 ash being processed through the silo.

- Efficiency of the baghouse is 99.9%. When loading dry ash to an enclosed truck, the combination of the baghouse and the hose connection has an efficiency of 95%.

  Note that no efficiency requirements will be put in the Operating Permit as it is difficult to measure efficiency. In lieu of including control efficiencies in the permit, the source will be required to follow operation and maintenance procedures to assure that control equipment is functioning properly.

The Division determined that no Regulation No. 1 particulate matter standards are applicable. Operations (loading and unloading) at the ash silo are not considered fugitive emissions (PM requirements - Reg 1, Section III.D). 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 "product" 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 monitor 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 - The source shall be required to determine 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 sodium and absorbed SO_2 (the spent sorbent) from the dry sodium injection system is about 15%, by weight, of the fly ash produced. In the absence of credible evidence to the contrary, opacity emissions from the ash silo loading 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 - The source certified that they were out of compliance with the APEN reporting requirements for ash handling operations. As previously mentioned in the Title V permit application all emissions from ash handling were

grouped together and identified as fugitive emissions. A Revised APEN was submitted for emissions from ash handling sources with the Title V permit application. As previously discussed, currently there are no emissions from ash handling from Units 1 thru 3 and no fugitive emissions from ash handling. An ash silo was added to handle dry ash from Unit 4 in 1992 and should have been permitted at that time. After the Metro Agreement takes effect (January 1, 2003), ash from Unit 3 will also be processed through the ash silo. No construction permit was issued, however, the applicable requirements were directly incorporated into the operating permit by processing this unit as a combined construction/operating permit. 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.

I. Unit P002: Coal Handling System (Conveyors and One (1) 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 maintenance) or rail car unloading have been considered non-fugitive sources. Specifically these sources are the coal conveyors and the coal crusher. The source indicated in its Title V application that the coal handling system was first placed in service in 1950 and based on the information available to the Division and supplied by the applicant has not been modified since then. The coal handling system is therefore grandfathered from construction permit requirements.

The coal handling system is subject to the following applicable requirements:

- 20 % opacity (Regulation No. 1, Section II.A.1)
- APEN reporting (Reg 3, Part A, Section II)

The Division determined that no Regulation No. 1 particulate matter standards are applicable. Coal crushing and conveying is not considered a source of fugitive emissions (PM requirements - Reg 1, Section III.D) since emissions can be reasonably controlled. The Division also does not consider coal crushing or conveying 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 sources from coal handling was the conveyor system and 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 the following emission factors:

A. Coal Crusher: 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

B. Coal Conveying: See emission factors identified for the new rail car unloading station and associated conveyors.

3. Monitoring Requirements - Monitoring requirements for the coal handling system 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. The coal conveyors are covered. In the absence of credible evidence to the contrary, the Division will consider the coal crusher and conveyors to be in compliance with the 20% opacity requirement, provided the integrity of the crusher building is maintained and the coal conveyors are covered and the integrity of the covers is maintained.

4. Compliance Status - The source certified that they were in compliance with all applicable requirements for coal handling. As previously mentioned in the Title V permit application all emissions from coal handling were grouped together and identified as fugitive emissions. A Revised APEN was submitted for emissions from coal handling sources with the permit application. The coal handling system is currently in compliance with all applicable requirements.

J. Unit P003: Two (2) Dry Sodium Reagent Silos, Each Equipped with Bin Vent Filters

1. Applicable Requirements - The dry sodium reagent silos were included in the Title V permit application as insignificant activities (PM and PM_{10} emissions below APEN de minimis levels of 1 tpy). When Public Service was obtaining a construction permit for dry sodium reagent silos at their Cherokee facility, the Division and the source had agreed to use a more appropriate emission factor than was previously used by the source. Using this new emission factor, emissions from the dry sodium reagent silos were not below APEN de minimis levels and therefore required a permit. The source submitted a permit application for these units on July 6, 1998 and subsequently an initial approval permit 98DE0473 was issued on July 14, 1999. 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 in construction permit 98DE0473. Permit 98DE0473 identifies the following applicable requirements for these units:

- Visible emissions shall not exceed 20% opacity, except as provided for below (condition 1)
- During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six consecutive minutes in any sixty consecutive minutes (condition 1)

Based on engineering judgement, the Division has not included the opacity requirement for startup, process modification and adjustment of control equipment 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.

- Construction of this source must commence within 18 months of initial approval permit issuance date or within 18 months of the date on which such construction or activity was scheduled to commence as stated in the application. If commencement does not occur within the stated time the permit will expire on January 14, 2001 (condition 4).

  Note that these units were constructed and in operation prior to issuance of the construction permit. The previous emission factors the source had used to estimate these emissions indicated emissions below APEN de minimis levels. Units with actual uncontrolled emission below APEN de minimis levels are not required to have permits. Therefore, since these units have been constructed, this condition does not need to be included in the operating permit.

- Throughput of sodium reagent shall not exceed 17,500 tons/yr. Compliance with the yearly consumption limits shall be determined on a rolling twelve (12) month total (condition 5).
- Emissions of air pollutants shall not exceed the following limitations:

PM	0.015 tons/yr
PM_{10}	0.015 tons/yr

  Compliance with the annual limits will be determined on a twelve month rolling total (condition 8).

The Division determined that no Regulation No. 1 particulate matter standards are applicable. Operations at the dry sodium reagent silo are not considered fugitive emissions (PM requirements - Reg 1, Section III.D). The Division also does not consider the dry sodium reagent silo to be a manufacturing process (PM requirements - Reg 1, Section III.C) as dry sodium is not processed further prior to use. The dry sodium reagent is used to reduce SO_2 emissions from the boiler.

2. Emission Factors - Approval of emission factors is necessary to monitor compliance with the emission limitations. The source and the Division have agreed that emission factors from the background document for AP-42, Sodium Carbonate Production (formerly Section 5.16, now Section 8.12), dated January 1996 shall be used to monitor compliance with the emission limits. The emission factors are based on the average stack test results for product silo loading (test 23b). The

approved emission factors are as follows:

Pollutant	Emission Factor (lbs/ton)
PM	1.7
PM_{10}	1.7

The bin vent filters are presumed to operate at a control efficiency of 99.9%.

3. Monitoring Requirements - Monitoring requirements for these units consist of monitoring and recording monthly quantities of dry sodium processed and calculating monthly emissions. In order to apply the control efficiency of the bin vent filters to emission calculations, the bin vent filters will have to be maintained and operated in accordance with manufacturer's requirements and good engineering practices.

4. Compliance Status - As previously indicated, these emission units were included in the original Title V permit application as insignificant activities. In processing the construction permit application for dry sodium silos at Cherokee, the Division and the source agreed upon a different emission factor to estimate emissions from these units. With this new emission factor the dry sodium silos at Arapahoe could no longer be considered insignificant activities. Therefore, the source submitted an application for a permit for these units. Permit 98DE0473 was subsequently issued. As mentioned previously, the certification by the Responsible Official in the first semi-annual compliance report will serve as the self-certification that these units can comply with the requirements in permit 98DE0473.

K. Unit E001: Ingersol-Rand, Model XHP-900-CAT Air Compressor and Caterpillar Internal Combustion Engine, Model No. 3406, Serial No. 6TB14503, Rated at 400 hp, Diesel Fuel Fired.

1. Applicable Requirements - This air compressor was not included in the original Title V permit application. This unit was leased in June 1997 as a back-up air compressor system while repairs were being made to the primary plant air compressors. The intent was to use this unit only temporarily, however, the repairs to the primary system necessitated the need for supplemental compressed air. During the first twelve months of operation, this unit met the requirements for APEN exemptions in accordance with Reg 3, Part A.II.D.1.sss.1.(iii) and therefore was not required to have a construction permit. However, since this unit is to remain in service during repair of the plant compressed air system and as a back-up, the source submitted a permit application for this unit in July 1998. An initial approval construction permit, 98DE0474, was issued for this unit on July 14, 1999. 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 in construction permit 98DE0474. Permit 98DE0474 identifies the following applicable requirements for these units:

- Visible emissions shall not exceed 20% opacity, except as provided for below (condition 1)
- During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes. Opacity shall be measured by EPA Method 9 (condition 1).

  The Division will include the 30% opacity requirement for startup in the permit but not the 30% opacity requirement for process modification or adjustment of control equipment. Based on engineering judgement, the Division believes that the operation of the air compressor is relatively simple and that no process modifications can be made. In addition, since this unit does not have any air pollution control equipment, the 30% opacity requirement during adjustment of control equipment does not apply.

- Construction of this source must commence within 18 months of initial approval permit issuance or within 18 months of date on which such construction or activity was scheduled to commence as stated in the application. If commencement does not occur within the stated time the permit will expire on January 14, 2001 (condition 3)

  This unit was on site and in operation prior to applying for the construction permit. Therefore, this requirement does not apply and is not being included in the operating permit.

- Fuel consumption shall not exceed the following (condition 4):

No. 2 diesel fuel	52,500 gal/yr

  Compliance with the yearly consumption limit shall be determined on a rolling twelve (12) month total.

- Emissions of air pollutants shall not exceed the following limitations (condition 7):

PM	1.1 tons/yr
PM_{10}	1.1 tons/yr
SO_2	1.0 tons/yr
NO_X	15.9 tons/yr
VOC	1.3 tons/yr
CO	3.4 tons/yr

  Compliance with the yearly limits shall be monitored on a rolling twelve (12) month total.

Although not specifically identified in the construction permit, the following requirements apply to the air compressor:

- SO_2 emission shall not exceed 0.8 lbs/mmBtu (Reg 1, Section VI.B.4.b.(i)).

  Based on a hourly fuel consumption rate of 15 gal/hr and heat content of diesel fuel of 137,000 Btu/gal, the hourly heat input to the engine is 2 mmBtu/hr.

2. Emission Factors - Approval of emission factors is necessary to monitor compliance with the annual emission limits. The source proposed to use emission factors from AP-42, dated October 1996, Section 3.3, Table 3.3-1. Emission factors are as follows:

Pollutant	Emission Factor (lbs/mmBtu)
PM	0.31
PM_{10}	0.31
SO_2	0.29
NO_X	4.41
VOC	0.35
CO	0.95

3. Monitoring Requirements - Monitoring requirements for the air compressor include monitoring and recording fuel consumption and calculating emissions on a monthly basis. Compliance with the opacity requirements will be monitored by performing EPA Method 9 visible emission observations. The frequency of these observations will be based on the actual time this unit is operated. Based on the emission factor for SO_2, the engine is always in compliance with the Reg 1 SO_2 emission limit. Therefore, the Division will consider, in the absence of evidence to the contrary, that the air compressor is in compliance with the SO_2 requirements when burning diesel fuel.

4. Compliance Status - As previously indicated, this air compressor was not at the Arapahoe facility at the time the Title V application was prepared. The source applied for and received a construction permit when it became evident that this unit could no longer qualify as an APEN exempt and therefore permit exempt unit. Permit 98DE0474 was subsequently issued. As mentioned previously, the certification by the Responsible Official in the first semi-annual compliance report will serve as the self-certification that these units can comply with the requirements in permit 98DE0474.

L. Unit T001: 500 Gal Above Ground Gasoline Storage Tank

1. Applicable Requirements - This storage tank was included in the Title V permit application as an insignificant activity and identified as a 1,200 gal tank. In response to a request by the Division, the source indicated that the tank is actually a 500 gal tank and they were not sure whether the 1,200 gal tank identified in the Title V permit application as an insignificant activity was identified in error or whether the 500 gal tank replaced the 1,200 gal tank. Although this tank has emissions below APEN de minimis levels (1 tpy VOC), it is still subject to some requirements in Regulation No. 7 (Sections III.A, V.A and V.B). Reg 7, Sections III.A and V.A are included in the General Conditions of the permit. Reg 7, Section VI.B relates specifically to disposal of gasoline. Reg 3, Part C, 2nd paragraph says that a unit cannot be considered an insignificant activity if in doing so other applicable requirements would be avoided. Reg 3 contains provisions for APEN exemptions and exemptions from construction permit requirements that have similar language indicating that the exemptions cannot be taken if in doing so other applicable requirements would be avoided. However, in the case of APEN and construction permit exemptions, if only certain applicable requirements apply to those otherwise exempt units, the exemption can be taken. Specifically, under Reg 3, part B, Section III.D.4.b.(iii) a unit can still be considered exempt from construction permit requirements if the unit is only subject to Reg 7 work practice standards. The requirements in Reg 7 Section V.B are work practice standards. Therefore, the Division agrees that this tank can be considered an insignificant activity.

M. Unit M001: Cooling Towers - Three (3) Cooling Water Towers

1. Applicable Requirements - The cooling towers were first installed in 1950 and modified in 1990 - 1995. In 1990 – 1995, Public Service refurbished the cooling towers due to deterioration over the years, the structural fill material, fan decks, distributions piping and mist eliminators have been replaced. No changes were made to the design rates for the cooling tower circulating pumps, so there was no increase in emissions based on this maintenance activity. Therefore, the activities performed during 1990 – 1995 are not considered a modification for purposes of permitting requirements. Two of the cooling water towers are rated at 31,000 gal/min and one at 65,000 gal/min. Although these units are grandfathered from construction permit requirements, the following requirements apply to these units:

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

  Based on engineering judgement, the Division believes that for purposes of opacity emissions none of the conditions under Reg 1, Section II.A.4 apply. Specifically activities such as fire building, cleaning of fire boxes and soot blowing are not germane to cooling towers. In addition, there is really no “startup” involved in operating a cooling tower. Finally, the Division does not believe that adjustment of the control device (drift eliminators) can be done while operating the tower and that process modifications would be limited. Therefore, the

30% opacity requirement will not be included in the operating permit as the specific operating activities under which it applies does not occur with these units.

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

2. Emission Factors - Since cooling towers provide direct contact between the cooling water and the air passing through the tower, some liquid can be entrained in the air stream and emitted as "drift" droplets. Particulate matter contained in the "drift" is considered an emission as well as any chlorine or chloroform from water treatment chemicals used in the cooling tower. Approval of emission factors for these units is necessary to verify compliance with the emission limits. The source proposed to calculate emissions from the cooling towers in the following manner:

PM = PM_{10} = (water flow, gpm) x (water density, lbs/gal) x (% drift) x (31.3% PM/PM_{10} from drift) x (total solids, ppm)

Where: % drift = 0.001%
31.3% PM from drift - from EPA-600/7-79-251a, November 1979, "Effects of Pathogenic and Toxic Materials Transported Via Cooling Device Drift - Volume 1, Technical Report", page 63

VOC = $CHCl_3$ = (water flow, gpm) x (0.0527 lbs $CHCl_3$/mmgal)

Where: 0.0527 lbs/mmgal emission factor - from letter from Wayne C. Micheletti to Ed Lasnic, dated November 11, 1992 (see attached)

3. Monitoring Requirements - Monitoring requirements for the cooling towers consist of monitoring the annual water circulation rate for each tower and calculating emissions annually. In order to calculate emissions, the total solids content of the circulating water from each tower shall be analyzed annually.

4. Compliance Status - The source certified in their Title V application that these units were out of compliance with the APEN reporting requirements. An APEN was submitted with the Title V permit application, therefore, these units are currently in compliance with all applicable requirements.

N. Unit M002: 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 three cold solvent part cleaners. Two cleaners meet the requirements of Regulation No. 3, Part A, Section II.D.4.b.(vi) for small remote reservoir cold solvent degreasers and are 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 units that meet 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 units meet the requirements of Regulation No. 3, Part A, Section II.D.4.b.(vi) these units are in compliance with the requirements of Regulation No. 7, Section X.B by design. Annual certification by the Responsible Official that these units have 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 (gaseous) 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), lube oil storage tanks (< 40,000 gal), storage tanks with limited contents (< 400,000 gal), fuel (gaseous) 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>

Boiler steam vents - injection of feed water treatment chemicals (VOC emissions < 1 tpy)
Gasoline dispensing tank, 500 gal above ground (VOC emissions < 1 ton)
Service water tower (PM and PM_{10} emissions < 1 ton)
Sulfuric acid storage tank (6,000 gal above ground)

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

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

Plant laboratory

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

propane portable heaters

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

Welding machine

<u>Battery recharging areas (Reg 3 Part C.II.E.3.t)</u>

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

Mowers, snowblowers, etc...

<u>Fugitive emissions from landscaping (Reg 3 Part C.II.E.3.cc)</u>

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

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

Turbine hydrogen vents

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

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

Restrooms, copiers, etc...

Lubricating oil storage tanks < 40,000 gal (Reg 3, Part C.II.E.3.aaa)

Waste oil storage tank (350 gal above ground)
Ten (10) turbine lube oil (bowser) tanks
Four (4) seal oil tanks (300 gal above ground)

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

Diesel fuel tank for emergency generator (1,000 gal above ground)
Diesel fuel tank for air compressor engine and refueling heavy vehicles (8,000 gal above ground)
Diesel fuel tank for refueling heavy vehicles (500 gal above ground)

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

Emergency generator - diesel (rated at 600 hp and runs < 250 hrs/yr)

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

Not sources of emissions

Unit No. 1 turbine lube oil system (closed system)
Unit No. 2 turbine lube oil system (closed system)

Unit No. 3 turbine lube oil system (closed system)
Unit No. 4 turbine lube oil system (closed system)

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 since they are mobile sources. 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 boilers is coal. However, the source requested that these boilers be permitted to use natural gas or a combination of coal 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 alternate 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 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 commenced operation before August 17, 1971. The permit shield was granted based on the source's justification.

Note that although an electrostatic precipitator was added to Unit 1 in 1977, slipstream baghouses were added to Unit 2 in 1997 and baghouses were added to Units 3 and 4 in 1978 and 1984, respectively, these additions are not considered modifications as they resulted in a decrease in particulate matter emissions. In addition, although a dry sodium injection system was installed on Unit 4 in 1992, this addition is not considered a modification as it results in reduced SO_2 emissions. Finally, the addition of the low NO_X burners to Unit 4 in 1992 is also 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 burners 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 does not agree with this justification, these requirements are not applicable because this facility commenced construction prior to October 24, 1974. The shield was granted for this justification. **Note that this shield does not apply to the new railcar unloading facility.**

D. 40 CFR Part 63, Subpart Q (as adopted by reference in Colorado Regulation No. 8, Part E) - National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers - The permit application states that this requirement is not applicable because the cooling towers do not use chromium-based water treatment chemicals. The shield was granted based on the source's 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, or 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 for 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.2 SO_2 limit (1.1 lbs/mmBtu) is more stringent.
- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Sections IV.A, B, F and H), streamlined out since Acid Rain COM/CEM requirements (Part 75) are more stringent. . In the case of Reg 1, Section IV.F, the calibration requirement is streamlined out since Acid Rain CEM QA/QC requirements are more stringent and Reg 1, Section VII.A.2.a QA/QC requirements (40 CFR Part 60.13) for COM 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.2.a), except for the QA/QC requirements for the COM (40 CFR Part 60.13(d)), are streamlined out since Acid Rain COM/CEM requirements (Part 75) are more stringent.

Boiler No. 2, Unit B002

See Boiler No. 1, Unit B001 above. Same conditions streamlined for same reasons.

Boiler No. 3, Unit B003

See Boiler No. 1, Unit B001 above. Same conditions streamlined for same reasons.

Boiler No. 4, Unit B004

See Boiler No. 1, Unit B001 above. Same conditions streamlined for same reasons.

VII. Acid Rain Provisions:

Boilers No. 1, 2, 3 and 4 (Units 1, 2, 3 and 4) are affected units under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78. This facility 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) for each unit. Each unit is subject to a NO_X limit of 0.80 lbs/mmBtu on an annual average, however, the source submitted a NO_X averaging plan for Units 1 thru 4. Under the averaging plan, higher NO_X emissions from any one unit is acceptable, provided the average annual NO_X emissions from the four units together is 0.8 lbs/mmBtu or less.

As affected units under the Acid Rain Program, Boilers No. 1 thru No. 4 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.

Note that with the shutdown of Units 1 and 2 in 2003 that these units may be exempt from the Acid Rain program provided the requirements in 40 CFR Part 72 § 72.8, as adopted by reference in Colorado Regulation No. 18, are met and changes to the NO_X averaging plan for Units 3 and 4 will be required.

VIII. Accidental Release Program - 112(r)

Section 112(r) of the Clean Air Act mandates a new federal focus on the prevention of chemical accidents. Sources subject to these provision must develop and implement risk management programs that include hazard assessment, a prevention program, and an emergency response program. They must prepare and implement a Risk Management Plan (RMP) as specified in the Rule.

Section 68.215(e) of the Federal Clean Air Act requires the Division to address four issues in regards to operating permit sources subject to 112(r):

1. Verify source submitted and registered an RMP by deadline

EPA is in the process of setting up a Website specifically for 112(r) plans. All 112(r) sources will electronically submit their plans to this "designated central location". The Division will require sources certify in their annual compliance certification that they are/are not subject to 112(r) and they have/have not submitted a Risk Management Plan (RMP) to the designated central location by June 20, 1999. In addition, the Division will check the 112(r) website to verify that a RMP was actually submitted to the website by the deadline. Failure to submit a RMP by the June deadline by sources subject to 112(r) will be considered a permit deviation for reporting purposes under Title V.

2. Verify that source owner/operator has submitted a source certification or in its absence has submitted a compliance schedule.

As mentioned above, the Division will require that sources certify in their annual compliance certification that they are/are not subject to 112(r) and they have/have not submitted a Risk Management Plan (RMP) to the designated central location by June 20,1999. If they are subject to 112(r) but did not submit an RMP on time, a compliance schedule under the provisions of Title V must be submitted to the Division by the source. Failure to submit a RMP or a compliance schedule by the June deadline by sources subject to 112(r) will be considered a permit deviation for reporting purposes under Title V.

3. For some or all sources use one or more mechanisms such as completeness check, source audits, record review, or facility inspections to ensure permitted sources are in compliance with the requirements of this part

The Division may choose to perform any or all of the activities listed under this subsection. Although there is no specific number of such actions required in the 112(r) rule, a June 3, 1997 draft 112(r) implementation guidance from EPA states that "Congress considered a requirement that 1.4 percent of the RMPs be audited annually, but dropped that provision."

The Division will, at a minimum, perform a "completeness check" on an unspecified

number of Title V 112(r) sources. The website that EPA is in the process of developing to accept 112(r) RMP's will include software that will electronically conduct a completeness check on the RMP's. For the purposes of this operating permit, such check shall serve as the completeness check required under 68.215(e)(3). As noted in the Preamble to the final 112(r) rule (June 20, 1996 Federal Register, page 31691), "EPA agrees that the review for quality or adequacy of the RMP is best accomplished by the implementing agency..." In Colorado, the implementing agency is the U.S. EPA. If the EPA website software indicates that a source did not submit a complete plan, it will be considered a permit deviation for reporting purposes under Title V and the Division may initiate an enforcement action for failure to meet the Title V permit condition (see below). Per the Preamble (page 31691), the Division may perform the completeness checks in a timeframe consistent with the source's Title V certifications.

4. Initiate enforcement action as necessary

This refers to enforcement under Title V, not under Part 68 (112(r)). If a source fails to file a RMP or a compliance schedule by the June deadline or the EPA software indicates that the RMP is not complete, it will be considered a permit deviation for reporting purposes under Title V and the Division may initiate an enforcement action.