TECHNICAL REVIEW DOCUMENT
for
OPERATING PERMIT 96OPRO132

Public Service Company - Hayden Station
Routt County
Source ID 1070001

Prepared November thru December 1999 and January 2000
Jacqueline Joyce, Review Engineer
Revised August, October thru December 2000
Revised March 2001 based on comments received during the Public Comment Period

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, December 6, 1996, March 6, 1997, November 16, 1999, November 2 and December 12, 2000, comments on the draft permit received September 25, 2000, 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 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.

II. Source Description

This source is classified as an electrical services facility under Standard Industrial Classification 4911. This facility consists of two coal fired boilers. Unit 1 is rated at 205 MW and Unit 2 is rated at 300 MW. The Unit 1 ignitors utilize either natural gas or No. 2 fuel oil and the Unit 2 ignitors utilize No. 2 fuel oil for startup, shutdown and/or flame stabilization. As part of a consent decree entered by the District Court on August 19, 1996, Civil Action 93-B-1749, the following emission control devices were required to be installed on both Units 1 and 2: low NO_X burners with over-fire air (to control NO_X emissions), lime spray dryers (to control SO_2 emissions) and fabric filter dust collectors (to control PM emissions). The consent decree required that startup testing of the control devices on Unit 1 commence by December 31, 1998 and that startup testing of the control devices on Unit 2 commence by December 31, 1999. As of October 18, 1999 all control equipment required by the consent decree has been placed into service.

In August 1996 the Colorado Air Quality Control Commission (AQCC) adopted revisions to Colorado's Visibility State Implementation Plan (SIP), specified in a document entitled "Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Hayden Station Requirements", dated August 15, 1996. The U.S. EPA approved the Visibility SIP revisions at 62 Federal Register 2305 (January 16, 1997). These revisions, concerning the Hayden Station, implemented and enforced requirements identified in the Hayden consent decree. Only those provisions of the consent decree that dealt with visibility impairment (SO_2 and opacity) were included in the Visibility SIP revisions.

In addition to the coal fired boilers, other significant sources of emissions at this facility include fugitive emissions from coal handling, ash handling and disposal and vehicle traffic on paved and unpaved roads. Point source emissions of particulate matter include coal crushing and conveying, an ash storage silo, two (2) ash recycle silos (recycle ash used with lime in the spray dryer), two (2) lime storage silos, two (2) ball mill slakers (prepares lime slurry for spray dryer) and two (2) recycle mixers (prepares recycle ash as slurry for spray dryer). Additional emission units at this facility include two (2) cooling towers.

This facility is located at 13125 U.S. Highway 40, four miles East of Hayden, in

an area designated as attainment for all criteria pollutants. Wyoming, an affected state is within 50 miles of this facility. Flattops and Mt. Zirkel National Wilderness Areas, federal class I designated areas, are within 100 km of this facility. With respect to Prevention of Significant Deterioration (PSD) requirements, this facility is considered a major stationary source with emissions (including fugitives), in tons/yr, as follows:

Pollutant	Potential to Emit (PTE) - 100% Coal[1] (tons/yr)	Actual Emissions[2] (tons/yr)
PM[3]	2,191	693.7
PM_{10}[4]	910	302.6
SO_2[5, 6]	2,662	6,678.5
NO_X[7]	8,706	7,208.3
CO	495	369.9
VOC	62	44.4
Pb[8]	10	de minimis
HAPs[9]	197.5	81.1

[1]Boilers are firing 100% coal. Unit 1 can use natural gas and/or No. 2 fuel oil for startup, shutdown and/or flame stabilization. Unit 2 can use No. 2 fuel oil for startup, shutdown and/or flame stabilization. The boilers can achieve nominal minimum load on these start-up/stabilization fuels but only operate in this mode for short periods of time before coal firing is established in the unit.
[2]Actual emissions for Unit 1 and 2 consider control efficiencies of 99.9% for PM/PM_{10} for the baghouses.
[3]PTE for boilers is based on 0.03 lbs/mmBtu x design heat rate x 8760 hrs/yr
[4] PTE for boilers, is based on 92% of PM being PM_{10}
[5]PTE for boilers are based on 0.130 lbs/mmBtu x design heat rate x 8760 hrs/yr
[6]Actual emissions for the boilers are based on 1999 data and the SO_2 PTE is based on the emission limitations set in the consent decree, however, the consent decree did not require Unit 2 to begin startup testing on the SO_2 control equipment until 12/31/99 and is not required to meet the consent decree limitations until July 1, 2000 at the latest.
[7]PTE for boiler 1 is based 0.46 lbs/mmBtu and boiler 2 is based on 0.40 lbs/mmBtu
[8] PTE for lead is based on uncontrolled emissions, control efficiency is 97.5%
[9]PTE includes uncontrolled emissions of 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 for coal and ash handling, haul roads and the unit 1 cooling tower is based on information supplied in the Title V application. Potential to emit for the ash silo, unit 2 cooling tower, the lime silos,

lime slakers, recycle ash silos and recycle mixers are based on permitted emission limits. Actual emissions are based on the Division's 1999 emission inventory. Hazardous Air Pollutant (HAP) Emissions, both potential to emit and actual, for the boilers are based on APENs submitted September 30, 1996 (identifying mainly metallic HAPS), using 1995 data, as a result of the Air Quality Control Commission's requirement for public utilities to submit HAP addendums (APENs) on their boilers and information in the Division's 1999 emission inventory (HCl and HF emissions).

The source indicated in their Title V permit application that this facility is subject to 112(r), the Accidental Release Requirements. At that time Hayden would have been subject to 112(r) since chlorine gas storage exceeded threshold levels. However, chlorine is no longer used in the cooling towers at Hayden so this facility is no longer subject to the requirements in 112(r).

Both 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: Riley-Stoker, Model No. 2489, Serial No. 3447, Front-Fired Boiler, Rated at 1,963 mmBtu/hr. Coal-Fired, with Natural Gas and No. 2 Fuel Oil Used for Startup, Shutdown and/or Flame Stabilization. Unit 1 is Equipped with the Following Control Devices: Low NO_X Burners with Over-Fire Air, Lime Spray Dryers and a Fabric Filter Dust Collector.

1. Applicable Requirements - This unit was placed in service in July 1965. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 1,963 mmBtu/hr. This maximum can vary somewhat depending on the quality of the fuel used. This unit has a maximum continuous steam flow rating of 1,422,329 lbs/hr. This maximum steam flow rating cannot be exceeded. This unit is grandfathered from Reg 3, Part B permitting requirements.

Typically, the Division does not consider the addition of a control device to be a modification for purposes of permitting. The installation of the baghouses and the lime spray dryers do not result in an increase in emissions. The low NO_X burners may decrease NO_X emissions substantially but increase CO emissions slightly. However, in the case of Hayden, the addition of control equipment was required by the consent decree and qualifies as an environmentally beneficial pollution control project. No additional permitting or testing requirements were included in the consent decree for the potential increase in CO emissions from the low NO_X burners. Therefore, the Division does not believe it is appropriate to

include any other permitting requirements or emission limitations for a possible increase of CO emissions due to the addition of the low NO_X burner. It should be noted that Public Service Company did perform testing before and after the addition of the low NO_X burners and the testing for this unit indicated that there was no increase in CO emissions.

Unit No. 1 is subject to the following **standard** applicable requirements:

- Opacity shall not exceed 20%, except as provided for in Reg 1, Section II.A.4 (Reg 1, Section II.A.1)
- Opacity shall not exceed 30%, for a period or periods aggregating more than six (6) minutes in any sixty (60) minute period, during fire building, cleaning of fire boxes, soot blowing, start-up, process modifications, or adjustment or occasional cleaning of control equipment (Reg 1, Section II.A.4)
- Particulate emissions shall not exceed 0.1 lbs/mmBtu (Reg 1, Section III. A.1.c)
- Continuous emission monitoring (Reg 1, Section IV)
    - COM requirements (Reg 1, Section IV.B.1), when burning coal
    - CEM for SO_2 or fuel sampling (Reg 1, Section IV.B.2)
    - if CEM for SO_2 then CEM for either O_2 or CO_2 (Reg 1, Section IV.B.3)
    - Calibration of CEMs (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 IV.I)
- Sulfur dioxide emissions shall not exceed 1.2 lbs/mmBtu, when burning coal (Reg 1, Section VI.A.3.a.(iii))
- APEN reporting (Reg 3, Part A, Section II)
- Lead (Pb) emissions shall not be such that emissions result in an ambient lead concentration exceeding 1.5 Fg/SCM averaged over a one-month period (Reg 8, Part C) - This is a **State-only** requirement
- Acid Rain requirements as follows:
    - This unit has been allocated, on an annual basis, SO_2 allowances as listed in 40 CFR 73.10(b). If annual SO_2 emissions exceed the allocated allowances for that year, additional allowances must be obtained per 40 CFR Part 75 to cover emissions for that particular calendar year.
    - NO_x emissions of 0.46 lbs/mmBtu on an annual average basis (§ 76.7(a)(2)).
    - Acid rain permitting requirements per 40 CFR Part 72.
    - Continuous emission monitoring requirements per 40 CFR Part 75.

- The source is also subject to the sulfur dioxide allowance system (40 CFR Part 73) and excess emission requirements (40 CFR Part 77).

It should be specifically noted here that the state-only good practices opacity requirement (Reg 1, Section II.A.10) does not apply to this unit, since the consent decree (section XVIII.88) specifies that any change to currently applicable laws and regulations that would have the effect of relaxing any requirements under the decree would not apply to the source. The Division considers the state-only good practices opacity standard (Reg 1, Section II.A.10) to be less stringent than the consent decree opacity requirements and therefore, is not applicable to this source.

Section XXII of the **consent decree** identifies the minimum requirements that shall be included in the operating permit as applicable requirements. As specified previously in this document, revisions were made to Colorado's **Visibility SIP** in August 1996 and were approved by EPA in January 1997. These revisions implemented and enforced requirements identified in the Hayden consent decree. The following requirements are those applicable requirements that were identified in Section XXII of the consent decree. For those requirements that were included in the Visibility SIP that citation is in bold italics. These requirements will be included in the operating permit.

- Definitions of boiler operating day (Section II.2.b and ***Section VI.C.II.2.b***) and rolling average basis (Section II.2.x and ***Section VI.C.II.2.x***) will be included in the permit.
- Maintain and optimally operate the boilers and all pollution control equipment (Section V.7 and ***Section VI.C.V.7***)
- Sulfur dioxide requirements as follows:
  - 0.160 lbs/mmBtu on a 30 boiler operating day rolling average basis (Section V.8.a.ii.(1) and ***Section VI.C.V.8.a.ii(1)***)
  - 0.130 lbs/mmBtu on a 90 boiler operating day rolling average basis (Section V.8.a.ii.(2) and ***Section VI.C.V.8.a.ii(2)***)
  - Monitoring using CEMs (Section V.8.a.iii & v and ***Section VI.C.V.8.a.iii & v***)
  - 82% reduction of SO_2 emissions, on a 30 boiler operating day rolling average basis (Section V.8.a.iv and ***Section VI.C.V.8.a.iv***)
  - Data exclusions from daily SO_2 emissions (Section V.8.a.vi & viii and ***Section VI.C.V.8.a.vi & viii***), with catastrophic failure requirements in Section V.8.a.ix and ***Section VI.C.V.8.a.ix***
  - Requirements for operating SO_2 control system (Section V.8.a.vii and ***Section VI.C.V.8.a.vii***)

Note that the requirement to install lime spray dryers identified in Section V.8.a.i of the consent decree and Section VI.C.v.8.i of the Visibility SIP has not been included in the permit since, as of the initial draft date of this document, the lime spray dryers have been installed and are operational.

- Nitrogen Oxide requirements as follows:
  - o Unit 1 shall be limited to 0.46 lbs/mmBtu on a calendar annual average basis (Section V.8.b.ii.(1))

    Note that the consent decree actually provides for a NO_X limitation of 0.50 lbs/mmBtu on a calendar annual average basis. However, Section V.8.b.ii specifies that this limit applies unless more stringent State or federal standards are promulgated as final. On December 19, 1996, EPA promulgated the final Phase II NO_X emission limitation (61 FR 67111). These rules identified more stringent NO_X limitations (for group 1, phase II dry-bottom wall fired boilers, per 40 CFR Part 76 §76.7(a)(2)) than identified in the consent decree and therefore have been included in the permit as specified by the decree. The Division has adopted 40 CFR Part 76 by reference in Colorado Regulation No. 18.

  - o Monitoring using CEMs (Section V.8.b.iv)

  Note that the requirement to install low NO_X burners with over-fire air identified in Section V.8.b.i has not been included in the permit since, as of the initial draft date of this document, the aforementioned pollution control equipment has been installed and is operational. In addition, the statement in the decree allowing the permittee to seek an alternative NO_X emission limit, per Section V.8.b.iii, has not been included, since the NO_X limit is the same as the Acid Rain emission limit that the permittee has already indicated that they will comply with as referenced by their Phase II NO_X Compliance Plan submitted December 18, 1997.

- Particulate matter requirements as follows:
  - o 0.03 lbs/mmBtu, as averaged over six (6) hours of EPA's reference method for particulate testing (Section V.8.c.ii.(1) and ***Section VI.C.V.8.c.ii.(1)***)

    Note that this requirement is not clear regarding whether this is one performance test lasting six hours or the average of three two-hour performance tests (which is how NSPS Da requires compliance with the particulate matter requirement to be monitored). In the permit this is clarified to specify

compliance is demonstrated by the average of three two-hour tests.

- o Opacity of 20.0%, as averaged over each separate 6-minute period within an hour, beginning each hour on the hour (Section V.8.c.ii.(2) and ***Section VI.C.V.8.c.ii.(2)***);
- o Notwithstanding the above, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, opacity shall not exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (Section V.8.c.ii.(2) and ***Section VI.C.V.8.c.ii.(2)***).
- o Excusing of opacity readings in excess of limitations (Section V.8.c.iii and ***Section VI.C.V.8.c.iii***)
- o Performance testing for particulate matter within 100 days of passing flue gas through the baghouse (Section V.8.c.iv and ***Section VI.C.V.8.c.iv***)

  Note that performance testing for Unit 1 was conducted February 16, 1999 and for Unit 2 was conducted August 12 and November 9, 1999 so this requirement will not be included in the permit, per se. However, performance tests of the boilers will be required as periodic monitoring to monitor compliance with the particulate matter standards.

- o Compliance with the opacity limits shall be monitored using the COM (Section V.8.c.v and ***Section VI.C.V.8.c.v***)

Note that the requirements to install baghouses (Section V.8.c.i and ***Section VI.C.V.8.c.i***) and to maintain the electrostatic precipitator until the baghouses have been installed (Section V.8.c.vi) will not be included in the permit since, as of the initial draft date of this document, the baghouses have been installed and are operational.

- Maintain, calibrate and operate CEMS to measure accurately SO_2 and NO_X emissions from each unit, as well as CO_2 and flow, in full compliance with the requirements in 40 CFR Part 75 (Section VI.9 and ***Section VI.C.VI.9 – note that the Visibility SIP does not require installation of a NO_X CEM***)
- Maintain, calibrate and operate CEMS to measure accurately the opacity of emissions from each unit in full compliance with the requirements in 40 CFR Part 60, Appendix B, Specification 1 and 5 CCR, 1001-3, IV.A and B (Section VI.10 and ***Section VI.C.VI.10***).
- Install, maintain, operate and calibrate an accurate CEMS at the inlet flue gas stream to the lime spray dryer on each unit to

measure accurately SO_2 concentrations in lbs/mmBtu (Section VI.12.(a) and ***Section VI.C.VI.12.(a)***)

- Tie the coal feeders for each unit into the SO_2 CEMs such that the CEMs accurately reflect the date and time when the first coal feeder on each unit has started during each startup (Section VI.12.(b) and ***Section VI.C.VI.12.(b)***)
- Hourly average SO_2 concentrations, in lbs/mmBtu, shall be calculated at the inlet and outlet continuous emission monitors for each unit, in accordance with the requirements of 40 CFR Part 75 (Section VI.16 and ***Section VI.C.VI.16***). This data shall be used to determine:
  - hourly SO_2 percent removal, daily SO_2 average percentage removal and 30 day rolling average SO_2 percent removal (Section VI.16.a and ***Section VI.C.VI.16.a***)
  - daily average SO_2 emissions and 30 day and 90 day rolling averages (Section VI.16.b and ***Section VI.C.VI.16.b***)
  - First 2 hrs after first coal feeder has started can be excluded (Section VI.16.c and ***Section VI.C.VI.16.c***)

  Note that since the source has installed the required pollution control equipment and cannot at this time operate the boilers on natural gas only, the conditions for natural gas operation in Section V.16.d of the consent decree and Section VI.C.BI.16.d of the Visibility SIP have not been included in the permit.

- Quarterly excess emission reporting for SO_2 30 and 90 day rolling averages (Section VI.17 and ***Section VI.C.VI.17***).
- Hourly average NO_X concentrations in lbs/mmBtu shall be calculated in accordance with the requirement in 40 CFR Part 75. The hourly averages shall be used to calculate quarterly averages in accordance with the requirements in 40 CFR Part 75 (Section VI.18).
- Quarterly excess emission reporting for the opacity standards (Section VI.22 and ***Section VI.C.VI.22***)
- The opacity CEMS on Units 1 and 2 shall be properly recording data at least 98% of each unit's operating time each quarter, provided, however that if final federally-enforceable regulations are promulgated that impose new CEMs QA/QC requirements that have the effect of increasing the proportion of CEMS QA/QC activity time in relation to unit operating time, then the parties shall meet and confer with respect to making a minor modification of the decree to amend the 98% CEMS availability requirement accordingly (Section VI.23 and ***Section VI.C.VI.23***).

  As of the issue date of the permit, no federally enforceable regulations have been promulgated that increase CEMS QA/QC

activity time in relation to unit operating time. 40 CFR Part 75 § 75.21(b) specifies that the QA/QC requirements for COMs are in accordance with the requirements in 40 CFR Part 51, Appendix M. EPA reference method 203 is intended to address QA/QC requirements but a final rule has not been promulgated yet. The Division will include the 98% in the permit, as that is still appropriate. If, however, during the term of the permit the 98% must be revised based on the final version of EPA reference method 203, the permit can be reopened at a later date to address this.

- The natural gas requirements in Section VII.26 of the consent decree and Section VI.C.VII.26 of the Visibility SIP **have not been included** in the permit since the permittee has installed the required pollution control equipment and the boilers cannot operate on natural gas alone.

Note that any language regarding conversion to natural gas or burning natural gas only in any of the above consent decree or Visibility SIP conditions has not been included in the operating permit, since these units cannot operate on natural gas fuel alone.

Section XXII of the consent decree specifically identifies the requirements that shall be included in the operating permit. The source requested that some of the requirements that were not identified in Section XXII be included in the operating permit, specifically Section VIII.29 (emission limitation compliance dates) and Section XIV (Force Majeure). The Division believes that it is not necessary to include these requirements in the permit since the source has already installed the pollution control equipment and demonstrated initial compliance with the emission limitations and therefore, neither Section VIII.29 or Section XIV are necessary, since they address the construction of the pollution control equipment and initial compliance with the emission limitations.

The Division's review of those requirements that were not identified in Section XXII of the consent decree indicated that two requirements should be identified in the operating permit, since these requirements have a regulatory basis and were not negotiated conditions. In addition, as specified preciously in this document revisions were made to Colorado's Visibility SIP in August 1996 and approved by EPA in January 1997 to incorporate provisions of the Hayden consent decree. Where applicable the Visibility SIP citation is identified in bold italics. These requirements are as follows.

- For any hour that valid, quality-assured continuous emission monitor data for a unit is unavailable, SO_2 and NO_X emissions shall be calculated in accordance with the missing data substitution procedures contained in 40 CFR Part 75 (Section VI.20 and

Section VI.C.VI.20).

Note that the Division presumes that the SO_2 and NO_X emission limitations that the source shall be required to provide replacement data for are the SO_2 and NO_X requirements identified in the consent decree and Visibility SIP and this will be clarified in the permit. The Acid Rain NO_X and SO_2 emission limits are subject to the monitoring requirements in 40 CFR Part 75 and therefore the data replacement requirements apply to the Acid Rain NO_X and SO_2 requirements.

- Calculate opacity based on CEMS data for each six-minute period of time any boiler is operating, in the manner, frequency and interval as prescribed in the applicable regulation. (Section VI.21 and ***Section VI.C.VI.21***).

Coal is the primary fuel for these boilers. Secondary fuels (natural gas and No. 2 fuel oil) are used during non-routine periods such as startup, shutdown and/or other flame stability efforts. Colorado Regulation No. 1 provides different standards (i.e. SO_2 and CEM requirements) for the different fuels. The permittee submitted information which indicates that, for the past five years, "alternative" fuel use has comprised less than 1% of total heat input. The source has also indicated that this unit cannot operate on these alternate fuels alone. Therefore, the requirements for scenarios for burning solely natural gas or No. 2 diesel fuel have not been included in the operating permit. Reg 1 does not require that an averaged SO_2 limit be calculated for units burning a combination of fuels. Therefore, for this boiler, the source will not be required to maintain records of the heat input of alternate fuels and demonstrate that alternate fuels comprise less than 5% of the total heat input. However, maintaining records of the consumption of alternate fuels will be required to determine annual emissions.

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 the CEM is used for monitoring SO_2, then a CEM is required for either CO_2 or O_2. This unit is also subject to the Acid Rain Requirements and as such is required to continuously measure and record emissions of SO_2, NO_X (and diluent gas either CO_2 or O_2), and CO_2 as well as volumetric flow, and opacity. The Acid Rain CEM requirements are specified in 40 CFR Part 75. The consent decree required CEMs for SO_2 (both inlet and outlet), NO_X, CO_2, flow and opacity. The consent decree requires that the opacity CEM be in compliance with the requirements in 40 CFR Part 60 Appendix B, Specification 1,

and Reg 1, Sections IV.A and B and that the other CEMs be in compliance with the Requirements in 40 CFR Part 75. The consent decree also requires the opacity CEM to be properly recording data at least 98% of each unit's operating time each quarter.

The general requirement to install CEMs in Reg 1, Section IV.A and B will be streamlined out in favor of the Acid Rain requirements to install and operate CEMs. Also since the consent decree specifies that the opacity CEM be in compliance with the requirements in 40 CFR Part 60 Appendix B, Specification 1 and Reg 1, Sections IV.A. and B, the consent decree opacity CEM requirements will also be streamlined out in favor of the Part 75 opacity CEM requirements. Note that the consent decree 98% data availability requirement will remain in the permit. The Requirements in Reg 1, Section IV.H (maintaining a file for 2 years) will be streamlined out of the permit in favor of the Part 75 requirements for maintaining a file of data. Note that the operating permit (general condition No. 21) requires that records be maintained for five years. The COM QA/QC requirements in Part 75 reference 40 CFR Part 51, Appendix M and the reference method in Appendix M that addresses the COMs (reference method 203) has not been promulgated as of this date. Therefore, the calibration requirements in Reg 1, Section IV.F will be included in the permit to identify the QA/QC requirements for the COM. The consent decree identifies quarterly excess emission reporting requirements for SO_2 and opacity. Reg 1, Section IV.G specifies excess emission reporting requirements. Since the consent decree and Reg 1, Section IV.G identify different elements to be included in these reports, both the consent decree and Reg 1, Section IV.G excess emission reporting requirements will be included in the permit.

<u>Opacity</u>

This boiler is subject to multiple opacity requirements. This boiler is subject to the opacity requirements in Colorado Regulation No. 1, which include a 20% standard for most periods of operation and a 30% standard for certain special operational activities.

This boiler also has opacity requirements as identified in the consent decree. These standards are 20.0%, as averaged over each separate 6-minute period, beginning each hour on the hour and 30% opacity for certain operational activities that is similar to the Reg 1 30% standard. The consent decree requires that opacity be monitored using the COM and the language in the 20% opacity consent decree requirement (as averaged over each separate 6-minute period, beginning each hour on the hour) describes how the COM functions. The Reg 1 20% opacity requirement does not contain language describing how the COM functions as the 20% opacity requirement applies in general to all sources, many of which are not equipped with COMS. Although the consent decree specifically says that compliance with the opacity requirement will be monitored using the COMs, there may be times when Method 9 readings may be necessary. For

instance the source may be required to take Method 9 readings when the COMs are down (as required by the permit) or the Division may take a reading during a routine inspection or when a violation is suspected. The Division considers, that even with the specific "on the hour" language in the consent decree, this language does not prohibit a Method 9 reading from being taken at any time, not strictly "beginning each hour on the hour".

Therefore, the Reg 1 20% and 30% opacity requirements will be streamlined out of the permit since they are the same as or less stringent than the consent decree 20.0 % and 30% opacity requirements.

Sulfur Dioxide (SO_2)

This boiler is subject to several SO_2 requirements, including a Reg 1 SO_2 standard and two SO_2 standards from the consent decree. All standards are in the same units of lbs/mmBtu; however, each standard is different and each has a different averaging time. Therefore, these standards cannot be compared for stringency so all SO_2 standards will remain in the permit.

In addition, the consent decree imposes a percent SO_2 removal on this unit. The percent removal requirement cannot be compared for stringency with the lbs/mmBtu standards mentioned above and therefore the percent removal standard will remain in the permit.

Note that this unit is also subject to Acid Rain SO_2 requirements. Sources subject to Acid Rain must hold adequate SO_2 allowances to cover annual emissions of SO_2 (1 allowance = 1 ton per year of SO_2) for a given unit in a given year. The number of allowances can increase or decrease for a unit depending on allowance availability. 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 Reg 1 SO_2 standard. Note that the Acid Rain SO_2 allowances appear only in Section III (Acid Rain Requirements) of the permit.

Nitrogen Oxides (NO_X)

This unit is subject to a NO_X requirement from the consent decree and the Acid Rain NO_X requirements. For this unit the consent decree NO_X requirement and the Acid Rain NO_X requirement are the same. Since the Division is prohibited from streamlining any Acid Rain NO_X requirements out of the permit, as specified in Regulation No. 3, Part C, Section V.C.1.b, which says "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", the Division will streamline out the consent decree NO_X requirement.

It should also be noted that the consent decree contains requirements to calculate hourly and quarterly average NO_X concentrations (in lbs/mmBtu) in accordance with the requirements in 40 CFR Part 75. Since the consent decree NO_X limits were streamlined out in favor of the acid rain requirements, the provisions for calculating the hourly and quarterly average NO_X concentrations will also be streamlined out, as the consent decree requirements for calculating NO_X averages is the same as required for Acid Rain (i.e. pursuant to 40 CFR Part 75).

Particulate Matter (PM)

This unit is subject to two particulate matter standards, a Reg 1 particulate matter standard of 0.1 lbs/mmBtu and a consent decree particulate matter standard of 0.03 lbs/mmBtu. The consent decree particulate matter standard is as averaged over 6 hours of EPA's reference method test. The Division presumes that this is the average of three 2-hour tests. Typically, compliance with the Reg 1 standard is based on three, 1-hr tests. Therefore, although the averaging times to determine compliance with the standards are slightly different, since the Reg 1 standard is less stringent than the consent decree standard by nearly an order of magnitude, the Reg 1 standard will be streamlined out of the permit.

Consent Decree Requirements

Colorado's Visibility SIP was modified in August 1996 and approved by the EPA in December 1997, to implement and enforce the requirements identified in the Hayden consent decree. The revisions made to the Visibility SIP addressed only those provisions of the consent decree that dealt with visibility impairment (SO_2 and opacity). The consent decree requirements were incorporated into the Visibility SIP with only minor language changes and as a result the consent decree and Visibility SIP requirements are virtually the same. Therefore, the consent decree requirements have been streamlined out of the permit in favor of the Visibility SIP requirements, unless already streamlined in favor of other requirements as discussed above. Note that for any consent decree requirement streamlined in the above sections, the corresponding Visibility SIP requirement, if applicable, will be streamlined for the same justification.

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 or No. 2 fuel oil may be used for startup, shutdown and/or flame stabilization. The pollutants of concern are Particulate Matter, (PM and PM_{10}), Nitrogen Oxides (NO_x), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC).

Some hazardous air pollutants (HAPs) are generated through the combustion process. Approval of emission factors for this unit is necessary to the extent that accurate actual emissions are required to verify the need to submit Revised APENs to update the Division's Emission Inventory.

The source proposed to use emission factors from EPA's Compilation of Emission Factors (AP-42), for coal combustion - Section 1.1 (9/98), Tables 1.1-3, 1.1-6 and 1.1-19 for pre-NSPS wall-fired boilers burning bituminous coal, for No. 2 fuel oil, Section 1.3 (9/98), Tables 1.3-1, 1.3-3 and 1.3-6 for industrial boilers/boilers > 100 mmBtu/hr, using No. 2 (distillate) fuel oil 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 Coal (lbs/ton)	Emission Factor Natural Gas (lbs/mmSCF)	Emission Factor No. 2 Fuel Oil (lbs/10^3 gal)
PM	Source Test[1]	1.9	2
PM_{10}	0.92(PM)	1.9	1
SO_2	CEM	CEM	CEM
NO_x	CEM	CEM	CEM
CO	0.50	84	5
VOC	0.06	5.5	0.2

[1]As discussed in the monitoring plan section of this document, source testing has been conducted on Units 1 and 2 and the results of these tests shall be used to calculate emissions. The emission factors to be used are 0.0122 lbs/mmBtu for Unit 1 and 0.0109 lbs/mmBtu for Unit 2.

Lead emissions shall be calculated as follows:

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

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

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

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

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

This boiler is equipped with a baghouse, low NO_X burners with over-fire air and lime spray dryers to control particulate, NO_X and SO_2 emissions respectively. Provided the source maintains the baghouse per manufacturer's recommendations and good engineering practices, a 99.9% efficiency can be applied to the PM and PM_{10} emission factors when burning natural gas or No. 2 fuel oil and an efficiency of 99.3% can be included in the lead emission calculation when burning coal. The permit will not specifically identify any maintenance requirements for the other control devices since the source will be required to use their CEM to determine NO_X and SO_2 emissions and monitor compliance with the emission limitations.

3. Monitoring Plan - Compliance demonstration and monitoring requirements for this unit are identified in sections 1 - 2 of Section II of this permit. Conditions 1.1 through 1.18 cover coal and Condition 2.1 covers alternate fuels used for startup, shutdown and/or flame stabilization.

The Visibility SIP and the Acid Rain program require the source to install, certify and operate continuous emission monitoring equipment for opacity, SO_2 (both inlet and outlet), NO_X, CO_2 and volumetric flow and require the source to use these monitors to monitor compliance with the opacity, SO_2 and NO_X requirements. These monitors shall be operated in accordance with the requirements in 40 CFR Part 75. 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 appear to address opacity monitors. It appears that this reference is an error. However, the EPA has indicated that this reference is not an error, although, the reference method to address opacity monitors (reference method 203) has not been promulgated yet. Therefore, the Division is including the COM calibration requirements in Reg 1, Section IV.F in the permit for the COM QA/QC requirements. It should be noted that § 75.24(e), which addresses COM out-of-control periods, also references 40 CFR Part 51, Appendix M. The permit provides alternate monitoring requirements when the COM and CEMs are out of control. In addition, the Visibility SIP requires that the COM properly records data at least 98% of the unit's operating time each quarter.

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

copy of the quarterly certification that monitoring data has been recorded in accordance with the applicable requirements and the annual compliance certification.

Typically, the Division would require that compliance with the PM standard be demonstrated through source testing and depending on the results of the performance test, the frequency of stack testing for PM emissions would vary. As a result of the consent decree, a stack test was recently performed on Unit 1 with the average of the three two (2) hour tests being 0.0122 lbs/mmBtu. According to the stack testing requirement that the Division has incorporated into other coal-fired utility boiler permits, no additional testing would be required during the permit term, since the test results are less than 50% of the standard. Although this testing was performed prior to issuance of the permit, the Division will not require any additional testing for the PM standard during the permit term. In this case, the Division has included the annual stack test requirement (plus the language stating that based on the results subsequent stack testing may be less frequent) in the permit, primarily for informational purposes, since this same language would be included in the permit upon renewal. The Division has included a note in the permit stating that the testing for Unit 1 was completed and was less than 50% of the standard therefore, no performance testing will be required for this permit term. Finally, it should be noted that since this test has not been approved, the Division may request further testing in order to approve this compliance testing. If necessary, the permit may be reopened as a result of the Division's review of this performance test.

Annual emission calculations, for all pollutants except SO_2 and NO_X, will be required to monitor 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. 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.

The source has indicated that both natural gas, No. 2 fuel oil or a combination of the two may be used in startup, shutdown and/or flame stabilization. Use of these fuels shall be recorded annually and used to calculate emissions for the purposes of APEN reporting.

4. Compliance Status - The source indicated in their Title V permit application that this unit was in compliance with all applicable requirements. This source is subject to a consent decree (entered by the District Court on August 19, 1996, Civil Action 93-B-1749) and is currently meeting the requirements of the decree.

B. Unit B002: Combustion Engineering, Model and Serial No. 1337, Tangentially Fired Boiler, Rated at 2,712 mmBtu/hr. Coal-Fired with No. 2 Fuel Oil Used for Startup, Shutdown and/or Flame Stabilization. Unit 2 is Equipped with the Following Control Devices: Low NO_X Burners with Over-Fire Air, Lime Spray Dryers and a Fabric Filter Dust Collector.

1. Applicable Requirements - This unit was placed in service in 1976. The source indicated in the permit application that this unit, for all practical purposes, has a maximum heat input rate of 2,712 mmBtu/hr. This maximum can vary somewhat depending on the quality of the fuel used. This unit has a maximum continuous steam flow rating of 1,994,329 lbs/hr. This maximum steam flow rating cannot be exceeded.

This unit is permitted with applicable requirements identified in Colorado Construction Permit 10RO173 (final approval modification dated June 3, 1997).

Typically, the Division does not consider the addition of a control device to be a modification for purposes of permitting. The installation of the baghouses and the lime spray dryers do not result in an increase in emissions. However, the low NO_X burners may decrease NO_X emissions but increase CO emissions. However, in the case of Hayden, the addition of control equipment was required by the consent decree and qualifies as an environmentally beneficial pollution control project. No additional permitting or testing requirements were included in the consent decree for the potential increase in CO emissions from the low NO_X burners. Therefore, the Division does not believe it is appropriate to include any other permitting requirements or emission limitations for a possible increase of CO emissions due to the addition of the low NO_X burner. It should be noted that Public Service Company did perform testing before and after the addition of the low NO_X burners and the testing for this unit indicated that there was no increase in CO emissions.

This unit is subject to the same **standard** applicable requirements as Unit 1, with the following exception:

- Acid Rain requirements as follows:
  - NO_x emissions of 0.40 lbs/mmBtu on an annual average basis (§ 76.7(a)(1)).

This unit is subject to the same applicable requirements as identified in the **consent decree** as Unit 1, with the following exceptions:

- Nitrogen Oxide requirements as follows:
  - Unit 2 shall be limited to 0.40 lbs/mmBtu on a calendar annual average basis (Section V.8.b.ii.(2))

Note that the consent decree actually provides for a NO_X limitation of 0.45 lbs/mmBtu on a calendar annual average basis. However, Section V.8.b.ii specifies that this limit applies unless more stringent State or federal standards are promulgated as final. On December 19, 1996, EPA promulgated the final Phase II NO_X emission limitation (61 FR 67111). These rules identified more stringent NO_X limitations (for group 1, phase II tangentially fired boilers, per 40 CFR Part 76 §76.7(a)(1)) than identified in the consent decree and therefore have been included in the permit as specified by the decree.

Colorado Construction Permit 10RO173 identifies the following applicable requirements:

- Visible Emissions shall not exceed 20% opacity (condition 1)
- Emissions of air pollutants shall not exceed the following limitations (condition 2):
  - SO_2 emissions shall not exceed 1.2 lbs/mmBtu
  - Particulate matter emissions shall not exceed 0.1 lbs/mmBtu
- A suitable gas-conditioning agent shall be injected into the fluegas upstream of the air pollution control equipment on an as-needed basis as long as an ESP is used for particulate control so as to maintain compliance with applicable particulate regulations of the Commission. Any testing or modification of such gas-conditioning techniques must involve discussion with and approval by the Division (condition 4).

  Note that this requirement will not be included in the operating permit as the ESP on Unit 2 was replaced with a baghouse. The baghouse was placed in operation on May 20, 1999, as indicated by PSCo's additional information submittal received November 16, 1999.

- Emissions monitoring equipment/systems at Hayden Unit 2 as required in 40 CFR Part 60 Subpart D, Part 75, Regulation No. 1, Section IV and Regulation No. 6, Part A for opacity, sulfur dioxide concentration and nitrogen oxide concentration must be operated continuously. Any violation of the Commission's emission standards must be reported immediately to the Division in accordance with procedures specified by the Division. A full record of such continuous in-stack measurements in a format specified by the Division shall be submitted to the Division quarterly (condition 5).

  It is not clear what the immediate reporting of excess emissions in

accordance with Division standards was intended to require. It is presumed that the term "immediate" in this case is intended to be defined by the time requirement specified in the appropriate regulation. Typically, the Division only requires immediate reporting of excess emissions if excess emissions occurred as a result of an upset condition (Common Provisions Section II.E) or Emergency Provisions (Reg 3, Part C, Section VII) and the source wishes to claim an upset or emergency provision, otherwise only quarterly reporting of excess emissions is required. The consent decree only requires immediate reporting of excess emissions if due to unpredictable failure of air pollution control equipment or process equipment (opacity only) or catastrophic failure (SO_2) only. Such special reporting requirements of excess emissions are included in the operating permit either as general conditions (upset and emergency provisions) or in the specific requirements for Unit 2 (consent decree requirements). Therefore the requirement for "immediate" reporting of excess emissions will not be included in the permit.

- All applicable requirements of the Consent Decree which was entered by the District Court on August 19, 1996, Civil Action 93-B-1749 shall be met (condition 7).

  As specified previously for Unit 1, the requirements from the consent decree have been incorporated into the Visibility SIP. As discussed in the various applicable requirement streamlining section for Unit 1 the consent decree requirements have been streamlined out of the permit in favor of the Visibility SIP or other regulations, as appropriate.

- The requirements of Regulation No.1, Section II.A.10 shall be met (condition 8).

  The consent decree (section XVIII.88) specifies that any change to currently applicable laws and regulations that would have the effect of relaxing any requirements under the decree would not apply to the source. The Division considers the state-only good practices opacity standard (Reg 1, Section II.A.10) to be less stringent than the consent decree opacity requirements and therefore, this requirement is not applicable to the source and will not be included in the permit.

Although not specifically identified in the construction permit or identified as a **standard** applicable requirement, this unit is subject to the following additional applicable requirements:

- NSPS Subpart D Requirements (40 CFR, Part 60, Subpart D as adopted by reference in Colorado Regulation No. 6, Part A)
  - Emissions of Particulate Matter shall not exceed 0.1 lbs/mmBtu (§ 60.42(a)(1))
  - Opacity shall not exceed 20%, except for one six-minute period of not more than 27% (§ 60.42(a)(2))
  - No opacity limits during start-up, shutdown and malfunction (§ 60.11(c)).
  - SO_2 emissions shall not exceed 1.2 lbs/mmBtu when burning coal (§ 60.43(a)(2)) and 0.8 lbs/mmBtu when burning No. 2 fuel oil (§ 60.43(a)(2)(1)). SO_2 standard is on a 3-hr rolling average (§ 60.45(g)(i)). A prorated SO_2 emission limit shall be calculated if a combination of fuels is burned (§ 60.43(b)).

    The requirement to calculate a prorated SO_2 limit will not be included for the reasons discussed below.

  - NO_X emissions shall not exceed 0.30 lbs/mmBtu when burning No. 2 fuel oil (§ 60.44(a)(2)) and 0.70 lbs/mmBtu when burning coal (§ 60.44(a)(3)). NO_X standard is on a 3-hr rolling average (§ 60.45(g)(3)). A prorated NO_X emission limit shall be calculated if a combination of fuels is burned (§ 60.44(b)).

    The requirement to calculate a prorated NO_X limit will not be included for the reasons discussed below.

    Coal is the primary fuel for these boilers. Secondary fuels (No. 2 fuel oil) are used during non-routine periods such as startup, shutdown and/or other flame stability efforts. The Construction Permit did not address secondary fuels. The NSPS, Subpart D sets forth emission limits when fuels are combined for combustion (i.e. prorating). The permittee submitted information which indicates that, for the past five years, “alternative” fuel use has comprised less than 1% of total heat input. By calculation, the Subpart D emission limits for this amount of natural gas, propane or fuel oil remain essentially unchanged from the coal emission limit. The Division therefore assumes the source is in compliance with Subpart D emission limits whenever alternate fuel use comprises less than 1% of total heat input. If alternate fuel use comprises more than 5% of total heat input during a year, the permit must be reopened to include Subpart D requirements for combined fuel combustion.

  - Source shall install, calibrate, maintain and operate

continuous monitoring systems for measuring opacity, SO_2 and NO_X emissions and either O_2 or CO_2 (§ 60.45(a)).

- NSPS General Provisions (40 CFR Part 60 Subpart A, as adopted by reference in Colorado Regulation No. 6, Part A), specifically:
  - Good practices (§ 60.11(d))
  - Circumvention (§ 60.12)

Streamlining of Applicable Requirements

Continuous Emission Monitors

Streamlining of continuous emission monitoring systems requirements is the same as discussed for Unit 1, with the following exceptions. Unit 2 is required by 40 CFR Part 60 Subpart D § 60.45(a) to install calibrate, maintain and operate continuous monitoring systems for opacity, SO_2, NO_X and either O_2 or CO_2. As allowed by the EPA (see attached), the requirements in 40 CFR Part 60 Subparts A and D, for the continuous emission monitoring systems will be streamlined out of the permit in favor of the more stringent Part 75 requirements. However, the COM will be subject to QA/QC requirements in 40 CFR Part 60 Subpart A § 60.13. The excess emission reporting requirements in 40 CFR Part 60 Subparts A and D will remain in the permit, as well as the consent decree excess emission reporting requirements, since the consent decree and NSPS reporting requirements identify different elements to be reported. Since the NSPS QA/QC requirements and excess emission reporting requirements will be include in the permit, the calibration and excess emission reporting requirements in Reg 1, Sections IV.F and G will be streamlined out of the permit in favor of the NSPS requirements.

Opacity

Streamlining of the opacity standards is the same as discussed for Unit 1, with the following exceptions. Unit 2 is subject to an NSPS opacity requirements of 20% with one six minute period per hour not to exceed 27%. NSPS exempts the source (§ 60.11(c)) from the opacity standards when the source is in start-up, shutdown, or malfunction.

The consent decree opacity requirements (20.0% normal & 30% certain operational activities) are more stringent than the NSPS opacity requirements during startup, shutdown, malfunction and when no certain operational activities, except startup, are occurring. The NSPS opacity requirements are more stringent than the consent decree 30% opacity requirement during periods of fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment (see attached opacity matrix). Therefore, since none of the standards are more stringent for all operating conditions, all opacity conditions remain in the operating permit.

In their comments on the draft operating permit, the source requested that the Division streamline out the NSPS exemption (40 CFR Part 60 Subpart A § 60.11(c)), since the consent decree opacity requirements apply during the exemption period, this exemption for all practical purposes does not apply.

Sulfur Dioxide (SO_2)

Streamlining of the SO_2 requirements is the same as discussed for Unit 1, with the following exceptions. Unit 2 is subject to an NSPS SO_2 standard of 1.2 lbs/mmBtu on a 3 hour rolling average, which is the same standard as the Reg 1 SO_2 requirement.

Although not specifically stated in NSPS D, the Division has determined after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported with the quarterly excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "...it was recognized that sources which ordinarily comply with the standards may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards". In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, since the Regulation No. 1 SO_2 limits are equal to the NSPS D requirements and since the Reg 1 SO_2 limits apply all the time, the Division has streamlined out the NSPS D SO_2 limit in favor of the Reg 1 SO_2 limit. Note that although the Reg 1 SO_2 standards, which are included in the operating permit apply all the time, a malfunction may be reported to the Division as an upset condition in accordance with the requirements in Section II.E of the Common Provisions Regulation.

Nitrogen Oxides (NO_X)

Streamlining of the NO_X requirements is the same as discussed for Unit 1, with the following exceptions. Unit 2 is subject to an NSPS NO_X standard of 0.7 lbs/mmBtu on a 3 hour rolling average. Although the Acid Rain requirement is lower, it has a longer averaging time and therefore the requirements cannot be reasonably compared for stringency. As a result, both the NSPS and the Acid Rain NO_X requirements will be included in the permit.

Note that as discussed for SO_2 above, the NSPS NO_X standard does not apply under conditions of startup, shutdown and malfunction.

Particulate Matter (PM)

Streamlining of the particulate matter requirements is the same as discussed for Unit 1, with the following exceptions. Unit 2 is subject to an NSPS particulate matter standard of 0.1 lbs/mmBtu. Like the Reg 1 particulate matter standard compliance with the NSPS standard is monitored with three 1-hr performance tests. As discussed under SO_2 above, the NSPS particulate matter standard does not apply under conditions of startup, shutdown and malfunction. The consent decree particulate matter standard applies at all times. Therefore, for the same reasons as discussed under Unit 1, the NSPS particulate matter standard will be streamlined out of the permit in favor of the more stringent consent decree particulate matter standard.

Consent Decree Requirements

Streamlining of the consent decree requirements is the same as discussed for Unit 1.

2. Emission Factors - See discussion for Boiler No. 1 emission factors. Note that the emission factor for CO, when burning natural gas for Unit No. 2 is 24 lbs/mmSCF and the PM emission factor, when burning coal, is 0.0122 lbs/mmBtu (based on a stack test).

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

4. Compliance Status - The source indicated in their Title V permit application that this unit was in compliance with all applicable requirements. This source is subject to a consent decree (entered by the District Court on August 19, 1996, Civil Action 93-B-1749) and is currently meeting the requirements of the decree.

C. Unit F001: Fugitive Particulate Emissions from Coal Handling and Storage

D. Unit F002: Fugitive Particulate Emissions from Ash Handling, Hauling and Disposal

E. Unit F003: Fugitive Particulate Emissions from Paved and Unpaved Roads

1. Applicable Requirements - The Title V permit application did not provide dates when the coal handling or ash handling activities began operation. The Title V permit application indicates that the paved and unpaved roads at the plant began operation in 1962 and are therefore grandfathered from construction permit requirements. The ash handling operations (both fugitive and point sources) are addressed on three construction permits. Fugitive particulate emissions from coal handling are generated from storage and movement (dozing) of coal at the pile and unloading of coal from trucks. The entire coal handling system for Unit 1 (truck unloading, pile, crushers and conveyors) was first placed in service in 1965. Additional coal handling equipment to support

Unit 2 was added and first placed in service in 1973. Included with these additions was an additional missile (missile 3B), which deposits coal in another area of the coal pile. The Division considers emissions generated from depositing coal from the missile to the pile to be fugitive emissions. Therefore, all fugitive emissions from coal handling, except for missile 3B are grandfathered from construction permit requirements.

The pertinent applicable requirements for fugitive particulate emissions from the grandfathered coal handling activities and vehicle traffic (not ash hauling) on roads 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 particulate 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.

The pertinent applicable requirements for missile 3B are as follows:

- Coal processed through the missile shall not exceed 2,300,000 tons/yr (as requested in November 2, 2000 letter from the source)

  Note that the requested coal throughput is based on the design rate of both units, since the 1973 coal handling additions are capable of serving both Units 1 and 2, with additional capacity for stockpiling.

- The following fugitive particulate emission control measures shall be used to minimize fugitive particulate emissions (as indicated in November 2, 2000 letter from the source)
  - Dust collection and suppression at conveyor drop points will be used, as needed, to control fugitive dust from the missile.
  - The coal unloading missile shall be operated and maintained to minimize fugitive emissions from this operation. This includes maintaining the integrity of the missile and periodic inspections of the door seals to minimize coal dust leakage from these openings.

Fugitive particulate emissions are generated from ash handling (transportation) and operation of the ash disposal site. The Title V permit application does not indicate when ash handling operations first began. An ash silo was place in service in 1974 and a permit application for this facility was submitted in October

1977 to address removal of ash from the plant site to a disposal site. The ash handling permit, 11RO590-1 (final approval modification, dated January 17, 1996) is for the ash storage handling and transport system. This permit covers activities associated with the ash silo, permitted under 13RO598. The ash silo and activities associated with it (i.e. loading and unloading) are not fugitive emission sources and are addressed further under the ash silo discussion. Permit 83RO246 (final approval, transfer of ownership, dated June 18, 1992) was issued for the ash disposal site and this permit includes many fugitive control measures included in permit 11RO590-1. In order to simplify the requirements for fugitive emission sources from ash handling, permits 83RO246 and 11RO590-1 will be combined and permit 11RO590-1 will be canceled.

Permit 83RO246 identifies the following applicable requirements:

- The following fugitive particulate emission control measures shall be used to minimize fugitive particulate emissions (condition 1):
  - Watering of the fly ash shall be sufficient to maintain a moisture content of 15-25% during handling and deposition.

    Note this requirement is difficult to enforce as it would require costly sampling of ash as handled and disposed to monitor compliance and sufficient moisture to control emissions may be more or less than 15-25%. Therefore this condition will be changed to state that "watering of the fly ash at the disposal site shall be sufficient to minimize fugitive emissions."

  - Vehicle speed on the haul roads to the disposal site shall be posted and limited to 30 mph.
  - Haul roads shall have a gravel surface and be watered 3-6 times daily depending on the weather.

    Again, this requirement is difficult to enforce and it is not clear that 3-6 times daily would be sufficient to minimize emissions, more or less watering may be required to sufficiently minimize emissions. Therefore, this requirement will be changed to "haul roads shall be graveled and sufficiently watered to minimize fugitive particulate emissions".

  - Fly ash in the haul trucks shall be watered to prevent blowing of ash enroute and trucks shall not be overfilled in order to prevent spillage.

    This condition addresses the unloading of ash, which is performed at the ash silo, which is not a fugitive emission

source and is discussed in the next section of this document.

- o Entryways to paved roads shall be gravelled to prevent carryout of mud and dirt onto the paved surface.

- Deposition of fly ash shall not exceed 287,000 cubic yards per year at the 118 acre landfill site.

  Based on the method that the permittee will be required to use to determine ash generated at the facility, it is more logical for the fly ash deposition limit to be in terms of tons. The original preliminary analysis for this permit provided an ash density of 85 lbs/cubic feet, therefore the ash deposition limit would be 329,332 tons/yr. This value will be included in the permit. In addition, the 118 acre size restriction will be removed from the permit. The permit is controlling the quantity of material disposed of at the site and requiring that the ash disposed of be sufficiently watered to prevent fugitive emissions. The Division does not believe that the additional requirement on the size of the landfill is necessary.

Permit 11R0590-1 identifies the following applicable requirements:

- The following fugitive particulate emission control measures shall be used to minimize fugitive particulate emissions (condition 1):
  - o Ash unloaded into trucks will be mixed with sufficient water to control fugitive particulate emissions.

    This condition addresses unloading at the silo, which as previously mentioned is not a fugitive emission source and will be addressed with the ash silo. This condition will not be included in the permit.

  - o The trucks will be fully covered to prevent spillage en route.

    Previously trucks were covered at the plant site to prevent spillage. However, since the ash is wetted prior to being unloaded from the silo into trucks, Public Service believes that it may not be necessary to cover the loads to prevent spillage. Therefore, in order to allow some flexibility, the Division will change this requirement to the following: "Trucks shall be loaded in a manner to prevent spillage en route."

  - o The permittee shall take adequate measures to prevent deposition of dirt and mud on improved public streets and roads as necessary to control fugitive particulate emissions.

A condition in permit 83RO246 addresses this particular control measure, so this control measure will not be included in the permit.

- Total ash disposed shall not exceed 648,000 tons/yr. Annual records of the actual production rate shall be maintained by the applicant and made available to the Division for inspection upon request (condition 2).

  This condition will not be included in the permit. The ash disposal limitation from permit 83RO246 will be included in the permit.

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 particulate with a relatively coarse size range and particulate matter less than 10 microns in diameter (PM_{10}).

Fugitive 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.

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

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

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

emission factors used were:

Pollutant	Task	Emission Factor[1]
PM	Storage Pile	1.6μ lbs/acre-hr
PM_{10}	Storage Pile[2]	0.175(1.6μ) lbs/acre-hr

[1] where: μ = wind speed, m/sec

[2] AP-42 did not provide an emission factor for PM_{10} source assumed 17.5 % of PM is PM_{10}

B. Unloading of Coal from Trucks: In its Title V permit application, the source used emission factors for drop/transfer points from AP-42 (dated January 1995), Section 13.2.4 to estimate emissions from coal unloading. Emissions were estimated using the following equation:

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

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

2. Ash Handling and Transportation

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

3. Vehicle Travel on Paved and Unpaved Roads

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

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

where: E = particulate emissions, in lbs/yr
VMT = vehicle miles traveled per year
k = particle size multiplier, dimensionless

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

In their Title V permit application, the source proposed to estimate emissions from vehicle travel on paved roads using emission factors from AP-42 (dated January 1995), Sections 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.

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

Since the ash handling and disposal site operations were issued permits with fugitive particulate emission control plans, the requirements in the control plans shall be included in the permit. For ash handling and disposal, the source shall be required to record the quantity of ash hauled and disposed of and maintain a rolling 12 month total of ash handled and disposed of.

Missile 3B (coal handling system) is also subject to a fugitive particulate emission control plan and must maintain a rolling twelve month total of coal processed.

4. Compliance Status - The source certified in its Title V permit application that they were in compliance with all applicable requirements for fugitive emissions from coal handling and ash handling. The source indicated in its Title V permit application that they were out of compliance with the APEN reporting requirements for fugitive emissions from vehicle travel on paved and unpaved roads and an APEN was submitted with the permit application.

Upon the review of this permit application, it was determined that portions of the coal handling system should have been permitted. Public Service submitted information on November 2, 2000, indicating requested permit levels for those portions of the coal handling system. The Division incorporated the appropriate applicable requirements directly into the operating permit by processing those portions of the coal handling system as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. In this case, the certification by the Responsible Official in the first semi-annual compliance report will serve as the self-certification that the 1973 portions of the coal handling system unit can comply with its applicable requirements.

F. 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 loading and unloading of the ash silo is considered a point source and as such is subject to emission fees. The Title V permit application does not identify a date when operations from ash handling were first placed in service, however, the source has indicated that the ash silo was first placed in service in 1974. The ash silo was permitted in 1982 when a bin vent filter was added to the silo. Previously, particulate matter emissions from the silo were controlled by routing exhaust from the silo to the inlet of the boiler electrostatic precipitator. Colorado Construction Permit 13RO598 (initial approval modification dated April 15, 1997) was issued for the ash silo. The ash silo was moved to final approval status based on the self-certification submitted July 30, 1997 that this unit was fully in compliance with each applicable requirement listed in the initial approval construction permit 13RO598. Permit 13RO598 identifies the applicable requirements for the ash silo, as follows:

- Visible emissions shall not exceed 20% opacity (condition 2)

  Note that this condition references the Reg 6, Part B, Section III.C.3, which is a state-only new source performance standard for manufacturing processes. This reviewer believes that this is the incorrect reference, since the ash silo is not considered a manufacturing process. The correct reference is to Reg 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.

- Emissions of air pollutants shall not exceed the following (condition 3)

PM	0.513 lbs/hr*	and	2.25 tons/yr
PM_{10}	0.513 lbs/hr*	and	2.25 tons/yr

The above emission limitations were based on an inlet dust concentration of 512.8 lbs/hr and an overall collection efficiency of 99.9% for the baghouse.

*The short term emission limits have not been included in the Operating Permit as a result of the Division's short term emission limit policy (based on the April 16, 1998 Colorado AQCC directive).

The above emission limits are based on an inlet dust concentration. For the source's other power plant ash silos, emissions are determined by AP-42 emission factors and the source would like to determine emissions consistently. The AP-42 emission factors predict emissions more conservatively and the Division will therefore allow this. The ash silo emissions will have to be increased to accommodate the AP-42 emission factors. PM and PM_{10} emissions will be increased to 17.19 tons/yr (0.07 tpy for loading and 17.12 tpy for unloading). In addition, the Division's short term emission limit policy requires annual throughput and emission limits on all permitted emission units. An ash and spent sorbent throughput limit of 228,321 tons/yr will be included in the permit to make this limitation practically enforceable and to be consistent with the Division's short term emission limit policy.

- Good practices language (condition 4)

  Typically the Division only includes this general good practices language when a permitted emission unit is subject to NSPS requirements. This emission unit is not subject to any NSPS requirements, although the opacity requirement identified in permit 13RO598 mistakenly referenced Reg 6, Part B, which contains state-only NSPS requirements. Therefore, this requirement will not be included in the permit.

- After each baghouse replacement, the following actions shall be taken within 45 days of replacement:
  - The manufacturer, model number and serial number shall be provided to the Division (condition 6).
  - A source test shall be conducted to monitor compliance with

the particulate matter limits. The test protocol must be in accordance with the requirements of the Division's Compliance Test Manual and shall be submitted to the Division for review and approval at least 30 days prior to testing (condition 7).

- An operating and maintenance plan for all control equipment and control practices shall be submitted to the Division (condition 8).

  Note that the requirement to submit a proposed recordkeeping format in this permit condition (no. 8) shall not be included as recordkeeping requirements are addressed in the operating permit.

These requirements are much more stringent than what has previously been required for other ash silos at the source's other facilities. The ash silo is an insignificant source of particulate matter emissions as compared to the potential particulate matter emissions from the boilers. It is unlikely that a baghouse replacement would result in a significant increase in emissions. Typically, the Division does not require stack testing when baghouses are replaced, although a permit modification may be required if the manufacturer and serial number are included in the permit. Therefore, these requirements will not be included in the permit.

The Division determined that no Regulation No. 1 particulate matter standards were 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 - There are two sources of emissions from the ash silo: loading and unloading the silo.

The first source is pneumatically loading fly ash from the boiler baghouses to the silo. The dry fly ash goes through a series of separators that drop ash into the silo, which is equipped with a bin vent filter. The bottom ash is conveyed from the bottom ash hoppers in each boiler to ash tanks where it is de-watered prior to be transported to the ash site for disposal. Bottom ash handling is not a source of air emissions as the bottom ash, which is much coarser than fly ash, is sufficiently wet to prevent any emissions.

During unloading, ash is fluidized in the bottom of the silo by a paddle-like

device. 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. Ash is unloaded into open trucks.

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 and for the purpose of paying fees. The Division will require the source to use emission factors from EPA's Compilation of Emission Factors (AP-42), Section 11.17, Table 11.17-4, Product Unloading - Enclosed Truck and Unloading - Open Truck, 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	1.5	unloading[2]	Water Sprays - 90%
PM_{10}	1.5	unloading[2]	Water Sprays - 90%

[1]Specifically from Table 11.17-4, Product Unloading - Enclosed Truck
[2]Specifically from Table 11.17-4, Product Unloading - Open Truck

3. Monitoring Plan - Monitoring requirements shall include maintaining monthly records of ash and spent sorbent throughput and calculating emissions monthly. The ash throughput shall be calculated using the quantity of coal consumed, the the average ash content of the coal and an 80%/20% fly ash bottom ash split. Based on an engineering analysis, Public Service has indicated that the quantity of additional lime and absorbed SO_2 (the spent sorbent) from the lime spray dryer system are 25%, by weight, of the fly ash produced. In the absence of credible evidence to the contrary, opacity emissions from the ash silo and ash unloading operation shall be presumed to be in compliance with the opacity requirement provided the control devices are properly maintained and operated.

4. Compliance Status - The source indicated in their Title V permit application that the ash silo was in compliance with all applicable requirements.

G. Unit P002: Coal Handling System (Conveying and Crushing)

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 truck unloading have been considered point sources. Specifically, these sources are the coal conveyors and the two coal crushers.

The entire coal handling system for Unit 1 (truck unloading, pile, crushers and conveyors) was first placed in service in 1965. Additional coal handling equipment to support Unit 2 was added and first placed in service in 1973 and therefore should have been issued a construction permit. The permitted coal handling equipment includes the following: conveyor 3B which takes coal from the base of crusher 2A to the 3B missile, which deposits coal in another area of the coal pile and conveyors 6A, 4B and 5B which take coal from the base of the 3B missile to the Unit 2 coal bunkers. The conveying system added to support Unit 2 includes 5 transfer points. Missile 3B is considered a source of fugitive particulate emissions and is addressed in the section on fugitive particulate emissions. One open transfer point is associated with missile 3B. The remaining portions of the 1973 coal handling addition are considered point sources, with a total of 4 enclosed transfer points.

The grandfathered portions of the coal handling system are subject to the following applicable requirements:

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

The permitted portions of the coal handling system are subject to the following applicable requirements.

- 20% opacity (Regulation No. 1, Section II.A.1)
- Coal processing rate of 2,100,000 tons/yr (as requested in November 2, 2000 letter from the source)

  Note that the requested coal throughput is based on the design rate of both units, since the 1973 coal handling additions are capable of serving both Units 1 and 2, with additional capacity to account for possible changes in fuel quality which could increase the quantity of coal burned.

- Air Pollutant emission, as follows (as requested in November 2, 2000 letter from the source)
  - PM 6.57 tons/yr
  - PM_{10} 3.11 tons/yr

The Division determined that no Regulation No. 1 particulate matter standards were 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 nonfugitive emission sources from coal handling were the conveyor system and the coal crushers. 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 Crushers: 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: 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 in conveying the coal from the storage pile to the boilers. The Division believes that this is a reasonable method to estimate emissions from coal conveying. The source proposed to use emission factors for drop/transfer points from AP-42 (dated January 1995), Section 13.2.4. Emissions from each transfer point (dropping material on a received surface) can be 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, %

3. Monitoring Plan - Monitoring requirements for the grandfathered portions of the coal handling system shall include maintaining annual records of coal throughput and calculating emissions annually. Compliance with the annual throughput and emissions limits for the 1973 portions of the coal handling system will be monitored by recording the quantity of coal processed and calculating emissions monthly. The coal crushers are 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 crushers and conveyors to be in compliance with the 20% opacity requirement, provided the integrity of the crusher buildings are 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.

Upon the review of this permit application, it was determined that portions of the coal handling system should have been permitted. Public Service submitted information on November 2, 2000, indicating requested permit levels for those portions of the coal handling system. The Division incorporated the appropriate applicable requirements directly into the operating permit by processing those portions of the coal handling system as a combined construction/operating permit as allowed by Colorado Regulation No. 3, Part C, Section III.B.7. In this case, the certification by the Responsible Official in the first semi-annual compliance report will serve as the self-certification that the 1973 portions of the coal handling system unit can comply with its applicable requirements.

H. Units P003 and P004: Two (2) Recycle Ash Silos Each Equipped with a Baghouse and Two (2) Recycle Mixers Each Equipped with a Chemco Scrubber

1. Applicable Requirements - These emission units were not identified in the original Title V permit application. The recycle ash silos and the recycle ash mixers are part of the SO_2 scrubber systems that were added to Units 1 and 2 as required by the consent decree. The ash recycle concept allows the recycle product consisting of a combination of fly ash, calcium sulfates and sulfites, and unreacted lime to absorb additional SO_2, thus increasing the overall efficiency of the removal process. A portion of the ash from the fabric filter dust collector hoppers is conveyed to one of two recycle storage silos. Water and solids from the recycle ash silo are introduced into the recycle ash slurry mix tanks. The recycle ash slurry is then pumped from the slurry mix tank to the head tank above the dry scrubber reactor.

The recycle ash silos are each equipped with an Industrial Accessories Company baghouse. Each baghouse has a 99.9% efficiency for particulate matter removal. Each recycle mixer is equipped with a Chemco scrubber. The scrubber consists of a water spray that knocks particulate matter out of the air stream before it is exhausted to the atmosphere. The scrubber efficiency is 95% for particulate matter removal.

Construction permits were issued for the recycle ash silos (98RO0376, final approval, dated January 26, 2000) and the recycle mixers (98RO0377, initial approval, dated November 19, 1998). The recycle mixers were given final approval status based on the self-certification submitted May 3, 1999 that these units were fully in compliance with each applicable requirement listed in their

initial approval construction permit (98RO0377). The applicable requirements for these units are as follows:

- Visible emissions shall not exceed 20% opacity during normal operation. During periods of startup, process modification or adjustment or occasional cleaning of control equipment, visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (98RO0376, condition 1 and 98RO0377, 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 mixing); 2) process modifications are unlikely since the process of loading and mixing is straightforward and if modifications were to occur, they could not occur while the unit is in operation (i.e. loading or mixing) 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 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 May 19, 2000 (98RO0377, condition 4).

  This requirement will not be included since the recycle mixers have commenced operation.

- Emissions of air pollutants shall not exceed the following limitations (98RO0376, condition 2 and 98RO0377, condition 5):

  <u>Silos:</u>

PM			0.17 tons/yr
PM_{10}			0.17 tons/yr

  <u>Mixers:</u>

PM	0.025 tons/mo	and	0.30 tons/yr
PM_{10}	0.025 tons/mo	and	0.30 tons/yr

- Raw material processing shall not exceed the following limitations (98RO0376, condition 3 and 98RO0377, condition 6):

  <u>Silos:</u>

Not to exceed			556,000 ton/yr

  <u>Mixers:</u>

Not to exceed	46,333 tons/mo	and	556,000 tons/yr

  Note that for the above two conditions, the monthly limits apply

during the first twelve months of operation. Since, as of the issue date of this permit, these silos and mixers will have been in operation for more than twelve months, the monthly limits will not be included in the operating permit.

The Division determined that neither the Regulation No. 1 (Section III.C.1) or Regulation No. 6 (Part B, Section III.C, including opacity) particulate matter standards were applicable to either the ash recycle silos or recycle mixers. The Division does not consider these to be manufacturing processes since the ash is a by-product of operating the boilers and the ash is recycled in the scrubber to control SO_2 emissions from the boilers.

2. Emission Factors - Both the silos and the recycle mixers are sources of particulate matter emissions. Approval of emission factors for these units is necessary as they will be used to demonstrate compliance with the emission limits.

For the recycle ash silos, the source will use Emission Factors from EPA's Compilation of Emission Factors (AP-42), Section 11.17, Table 11.17-4, Product Unloading - Enclosed Truck, dated January 1995. The emission factors are 0.61 lbs/ton for PM and 0.61 lbs/ton for PM_{10}. Provided the silo baghouses are maintained and operated in accordance with manufacturers' recommendations and good engineering practices, a control efficiency of 99.9% can be applied to the emission calculations.

The permittee proposed to use the manufacturers' guarantee of 0.02 gr/acfm particulate matter emissions for the recycle mixers. Based on a blower rating of 200 cfm and an hourly ash processing rate of 31.8 tons/hr (based on the annual throughput divided by 8760 hrs/yr and then divided by 2, to get the hourly processing rate for one unit), the emission factor is converted to 1.08×10^{-3} lbs/ton ash. This emission factor is less than the AP-42 emission factor (0.067 lbs/ton) for lime hydration with a wet scrubber in Table 11.17-2. It has been the Division's policy to require more stringent monitoring (i.e. stack testing or portable monitoring) for sources using emission factors less than AP-42 to monitor compliance with the emission limitations. However, the Division considers that the action involved in the recycle mixers is much different that the action involved in lime hydration (i.e. the lime slakers). Therefore, because the emission factor comparison is not truly a direct comparison and because estimated annual emissions are below 1 tpy, the Division will allow the use of these emission factors, without any additional monitoring requirements.

3. Monitoring Plan - In order to monitor compliance with the applicable requirements, the source will be required to monitor and record the quantity of lime processed and calculate emissions monthly. Compliance with the opacity limitation will be presumed, in the absence of credible evidence to the contrary, provided the baghouses on the silos and the scrubbers on the mixers are

operated and maintained in accordance with the manufacturers' recommendations and good engineering practices.

4. Compliance Status - These units were not included in the original Title V permit application but were added to the facility as part of the pollution control equipment for the boilers required by the consent decree. A final approval permit was issued for the recycle ash silos and the source has self-certified that the recycle mixers are in compliance with their construction permit requirements.

I. Units P005 and P006: Two (2) Lime Silos and Two (2) Ball Mill Slakers

1. Applicable Requirements - These emission units were not included in the original Title V permit application. The lime storage silos and lime slakers are part of the SO_2 scrubber systems that were added to Units 1 and 2 as required by the consent decree. Pebble size lime is delivered to the plant via self-contained pneumatic truck trailers. The lime is unloaded to the storage silos. The pebble lime flows by gravity through rotary feeders to a ball mill slaker, where it is slaked to a slurry of hydrated lime and water. The lime slurry is then pumped to a head tank above the dry scrubber reactor.

The lime storage silos are each equipped with an Industrial Accessories Company baghouse. Each baghouse has a 99.9% efficiency for particulate matter removal. Each ball mill slaker is equipped with a Chemco scrubber. The scrubber is composed of a series of baffles that act to force the moisture-entrained lime particles to drop out before the air stream is exhausted to the atmosphere. The scrubber efficiency is 95% for particulate matter removal.

Construction permits were issued for the lime silos (98RO0374, final approval, dated January 3, 2000) and the ball mill slakers (98RO0375, final approval, dated January 3, 2000). The applicable requirements for these units are as follows:

Lime Silos (98RO0374) and Ball Mill Slakers (98RO0375):

- Visible emissions shall not exceed 20% opacity during normal operation. During periods of startup, process modification or adjustment or occasional cleaning of control equipment, visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (98RO0374, condition 1 and 98RO0375, 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 slaking); 2) process modifications are unlikely since the process of loading and mixing is straightforward and if modifications were to occur, they could not

occur while the unit is in operation (i.e. loading or mixing) and 3) the control equipment cannot be adjusted while loading or unloading is occurring.

- Emissions of air pollutants shall not exceed the following limitations (98RO0374, condition 2 and 98RO0375, condition 2):
  Silos:
  PM 0.01 tons/yr
  PM_{10} 0.01 tons/yr
  Slakers:
  PM 0.80 tons/yr
  PM_{10} 0.80 tons/yr
- Raw material processing shall not exceed the following limitations (98RO0374, condition 3 and 98RO0375, condition 3):
  Silos:
  Lime stored shall not exceed 22,500 ton/yr
  Slakers:
  Lime processed shall not exceed 22,500 tons/yr

The Division determined that neither the Regulation No. 1 (Section III.C.1) or Regulation No. 6 (Part B, Section III.C, including opacity) particulate matter standards were applicable to either the lime silos or lime slakers. The Division does not consider these to be manufacturing processes since the lime is used in the scrubber to control SO_2 emissions from the boilers.

2. Emission Factors - Both the silos and the ball mill slakers are sources of particulate matter emissions. Approval of emission factors for these units is necessary as they will be used to demonstrate compliance with the emission limits.

For the lime storage silos, the source will use Emission Factors from EPA's Compilation of Emission Factors (AP-42), Section 11.17, Table 11.17-4, Product Unloading - Enclosed Truck, dated January 1995. The emission factors are 0.61 lbs/ton for PM and 0.61 lbs/ton for PM_{10}. Provided the silo baghouses are maintained and operated in accordance with manufacturers' recommendations and good engineering practices, a control efficiency of 99.9% can be applied to the emission calculations.

The permittee proposed to use the manufacturers' guarantee of 0.02 gr/acfm particulate matter emissions for the ball mill slakers. Based on a blower rating of 500 cfm and an hourly lime processing rate of 1.3 tons/hr (based on the annual throughput divided by 8760 hrs/yr and then divided by 2 (to get the hourly processing rate for one unit), the emission factor is converted to 0.067 lbs/ton lime. This emission factor is the same as the AP-42 emission factor for lime hydration with a wet scrubber in Table 11.17-2. The Division approves the use of this emission factor to monitor compliance with the emission limits.

3. Monitoring Plan - In order to monitor compliance with the applicable requirements, the source will be required to monitor and record the quantity of lime processed and calculate emissions monthly. Compliance with the opacity limitation will be presumed, in the absence of credible evidence to the contrary, provided the baghouses on the silos and the scrubbers on the slakers are operated and maintained in accordance with the manufacturers' recommendations and the permittee's operating experience.

4. Compliance Status - These units were not included in the original Title V permit application but were added to the facility as part of the pollution control equipment for the boilers required by the consent decree. These units are in compliance with all applicable requirements.

J. Unit M001: Unit 1 Cooling Tower, Rated at 84,000 gal/min
K. Unit M002: Unit 2 Cooling Tower, Rated at 134,000 gal/min

1. Applicable Requirements - The Unit 1 cooling tower was placed in service prior to February 1, 1972 and is therefore, grandfathered from construction permit requirements. The Unit 2 cooling tower was placed in service after February 1, 1972 and therefore requires a construction permit. A construction permit (96RO551-2, inital approval modification, dated April 16, 1998) was issued for the Unit 2 cooling tower. The Unit 2 cooling tower was moved to final approval status based on the self-certification submitted September 28, 1998 that this unit was fully in compliance with each applicable requirement listed in the initial approval construction permit 96RO551-2.

The Unit 1 cooling tower is subject to the following applicable requirements:

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

Construction permit 96RO551-2 identifies the following applicable requirements for the Unit 2 cooling tower:

- Emissions of air pollutants shall not exceed the following limitations (condition 2):

PM	15.4 tons/yr
PM_{10}	15.4 tons/yr
VOC	1.8 tons/yr

  After the submittal of the Title V permit application, Public Service refurbished the Hayden 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. However, the replacement of the drift eliminators resulted in better control of drift. With the original Title V permit application, the source indicated that the original drift eliminators kept the drift to 0.003%, however, with the refurbishment of the towers, the new drift eliminators now keep the drift to 0.001%. Therefore, based on this change Public Service Co has requested that the emission limits for PM and PM_{10} be decreased to 5.15 tons/yr based on the better drift eliminators.

- The source shall be limited to the following operating parameters (condition 3):
  - water flow shall not exceed 70,430.4 mmgal/yr
  - total dissolved solids/total suspended solids concentration shall not exceed 5,602 ppm
  - chlorination shall not exceed 730 hrs per year

  The source indicated, in comments on another facility's permit, that the intent of the total solids limit in construction permits was to provide design levels to set an emission limit and to set maximum parameters that determine emissions. The intent was for the source to demonstrate that they were below maximum parameters and therefore demonstrate compliance with emission limits, without performing calculations. However, since the operating permit requires monthly emission calculations, there is no need to set a limit on the total solids concentration. Therefore, the total solids concentration limit has not been included in the operating permit.

  Since the chlorination rate is used to determine emissions of chlorine (a HAP) from the Unit 2 tower it will not be included in the permit as a limitation since the Division does not have the authority to limit HAP emissions unless a source is requesting a synthetic minor limitation. In addition, although the source is required to report emissions of HAPs for the purposes of APEN reporting and payment of fees, the Division's policy is not to include these calculations in the specific portions of the operating permit. The APEN reporting requirements and the requirement to pay annual fees are included in the General Conditions of the operating permit and the source is still subject to these requirements.

Although not specifically identified in the construction permit, this cooling tower is also subject to the 20% opacity requirement in Colorado Regulation No. 1, Section II.A.1. In their Title V permit application, the source indicated that in a meeting with the Division (September 6, 1995 pre-application meeting), both the Division and Public Service agreed that cooling towers are always in compliance with the 20% opacity requirement. The Division does believe that it would be

highly unlikely that a cooling tower would ever violate the 20% opacity requirement. The Division considers that although it is unlikely that the cooling towers would violate the 20% opacity requirement, this requirement must be included in the operating permit. Therefore, the Division considers that the cooling towers are, in the absence of credible evidence to the contrary, in compliance with the opacity requirements provided the cooling water towers and their associated drift eliminators are operated and maintained in accordance with the manufacturer's recommendations and good engineering practices.

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 are 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 concentration, 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 Plan - For the Unit 1 cooling tower, the source will be required to monitor and record the water circulation rate and calculate emissions annually. In order to calculate emissions, the total solids content of the circulating water shall be analyzed annually. For the Unit 2 cooling tower, the source will be required to monitor and record the water circulation rate and calculate emissions monthly. Since the total solids concentration for the Unit 2 cooling tower has remained fairly consistent and well below 5609 ppm (the level at which the emission limits were set), the permit will require that the total solids content of the Unit 2 circulating water be analyzed semi-annually.

4. Compliance Status - The source indicated in their Title V permit application that the cooling towers were out of compliance with the APEN reporting requirements. An APEN and an application for a construction permit were submitted with the Title V permit application. Construction permit 96RO551-2 was subsequently issued for the Unit 2 cooling tower. The cooling towers are currently in compliance with all applicable requirements.

IV. Insignificant Activities

General categories of insignificant activities include: in-house experimental or analytical laboratory equipment, fuel (gaseous) burning equipment < 5 mmBtu/hr or < 10 mmBtu/hr (for heating), chemical storage tanks/containers < 500 gal or storage areas < 5,000 gal, landscaping and site housekeeping equipment (< 10 hp), storage of butane, propane or NGL (vessels < 60,000 gal), lube oil storage tanks (< 40,000 gal) and other storage tanks (limited throughput and contents), fuel storage and dispensing equipment, stationary internal combustion engines (limited size and hours of operation) and sources with emissions less than APEN de minimis. Specific insignificant activities identified in the Title V permit application are:

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

Solvent Cold Cleaners (VOC emissions < 2 tpy)
Boiler Steam Vents - emit VOC from injection of VOCs as treatment chemicals (< 2 tpy of VOC used)

<u>Units with emissions less than APEN de minimis - non-criteria reportable pollutants (Reg 3 Part C.II.E.3.b)</u>

Sulfuric acid tank, 12,000 gal, above ground
(2) 6,500 gallon 10% sodium hypochlorite (bleach) tanks

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

Plant Laboratory

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

Propane Portable Heaters

<u>Welding, soldering and brazing operations using no lead-based compounds (Reg 3 Part C.II.E.3.r)</u>

Maintenance Welding Machine

<u>Chemical storage tanks or containers < 500 gal (Reg 3 Part C.II.E.3.n)</u>

Oxygen scavenger chemical feed tank, 100 gal
(2) Phosphate chemical feed tanks, 200 gal

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

Battery Storage Areas (3)

Landscaping and site housekeeping devices < 10 hp (Reg 3 Part C.II.E.3.bb)

Mowers, Snowblowers, weedeaters, etc.

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

Operations involving acetylene, butane, propane or other flame cutting torches (Reg 3 Part C.II.E.3.kk)

Portable Welding Torches

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

Oil Drum Storage Area
Water Treatment Building

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

Sewage treatment plant (no VOC emissions)
Water runoff ponds
Raw water storage reservoir
Treated water pond
Fire protection collection tank (Unit 1), 25,000 gal underground
Fire protection collection tank (Unit 2), 30,000 gal underground
Bearing cooling water head tank, 260 gal
Condensate storage 1A, 6,530 gal
Condensate storage 1B, 6,530 gal
Condensate storage 2A, 50,000 gal
Condensate storage 2B, 50,000 gal
Potable water storage tank, 5,200 gal
Chem lab deionized water storage tank, 20 gal
Evaporation ponds
Ash water storage tanks
6,000 gallon scale inhibitor tank

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

Office emissions including cleaning, copying, and restrooms (Reg 3 Part C.II.E.3.tt)

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

Turbine lube oil reservoir (Unit 1), 3,000 gal above ground
Turbine lube oil tank 1A (Unit 1), 2,100 gal above ground
Turbine lube oil tank 1B (Unit 1), 4,500 gal above ground
Turbine lube oil tank 1C (Unit 1), 4,500 gal above ground
Turbine lube oil reservoir (Unit 2), 3,500 gal above ground
Turbine lube oil tank 2A (Unit 2), 5,500 gal above ground
Turbine lube oil tank 2B (Unit 3), 5,500 gal above ground
Waste oil tank, 600 gal above ground
Convault waste oil tank, 2,000 gal above ground
Transformer oil (Unit 1), 25,000 gal underground
Transformer oil (Unit 2), 30,000 gal underground
Turbine seal oil tank (Unit 2), 300 gal above ground
Electro-hydraulic fluid tank, 300 gal above ground

Fuel storage and dispensing equipment in ozone attainment areas throughput < 400 gal/day averaged over 30 days (Reg 3 Part C.II.E.3.ccc)

Gasoline storage tank (regular), 6,000 gal underground
Emergency fire pump fuel tank, 525 gal, above ground

Storage tanks with annual throughput less than 400,000 gal/yr and meeting content specifications (Reg 3 Part C.II.E.3.fff)

#1 diesel fuel oil tank, 1,000 gal underground
Fuel oil bulk storage tank, 250,000 gal above ground
Fuel oil day tank (Units 1 and 2), 15,000 gal underground
Convault diesel fuel tank, 5,200 gal above ground
Coal handling #2 diesel fuel tank, 8,000 gal underground
Emergency generator diesel fuel tank, 1,000 gal aboveground

Stationary Internal Combustion Engines - limited hours or size (Reg 3 Part C.II.E.3.nnn)

2 – 228 hp diesel emergency generator engines

Non-road Engines – limited hours or size (Reg 3, Part C.II.E.3.xxx)

368 hp diesel emergency fire pump

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

Sandblasting Machine

Not sources of emissions

Anhydrous ammonia tank, 30,000 gal above ground (empty)
Hydrogen tanks, 22 at 1,300 cu. ft. each, for generator cooling (tanks not vented, no emissions)
Hydrogen tanks, 6 at 3,467 cu. ft. each, for generator cooling (tanks not vented, no emissions)

The source also identified mobile engine tailpipe emissions as an insignificant activity. Emissions from these sources would not necessarily qualify them as an insignificant activity but they are not applicable to the Title V permitting requirements since they are mobile sources. Therefore, emissions from mobile sources are not identified in the draft permit as an insignificant activity.

V. Alternative Operating Scenarios

A. Alternate Fuels

The primary fuel used for both boilers is coal. Secondary fuels (natural gas and No. 2 fuel oil for Unit 1 and No. 2 fuel oil for Unit 2) are used during non-routine periods such as startup, shutdown and/or other flame stability efforts.

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 does not believe that this qualifies as an insignificant activity, 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 recordkeeping and operating requirements for the alternate 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 provided by the applicant and a review of the Division's files, the shield will be granted for the following non-applicable requirements. It should be noted that 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 and were last modified well before January 30, 1979. The permit shield was granted for this reason.

It should be noted that the addition of the control equipment (lime spray dryer, baghouse and low NO_X burners) to both boilers is not considered a modification in accordance with 40 CFR Part 60 Subpart A § 60.14(e)(5). 40 CFR Part 60 Subpart A is adopted by reference into Colorado Regulation No. 6, Part B, Section I.A.

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 **Boiler No. 1** as this boiler commenced operation and was last modified well before August 17, 1971. The permit shield was granted based on the source's justification. It should be noted that the addition of the control equipment (lime spray dryer, baghouse and low NO_X burners) to Boiler No. 1 is not considered a modification in accordance with 40 CFR Part 60 Subpart A § 60.14(e)(5).

Boiler No. 2 was placed in service prior to and has not been modified after September 18, 1978, therefore, this unit is not subject to the requirements in 40 CFR Part 60 Subparts Da, Db and Dc. Although not requested in the Title V

permit application, the Division will grant the permit shield for Boiler No. 2 from these non-applicable requirements. Again, it should be noted that the addition of the control equipment (lime spray dryer, baghouse and low NO_X burners) to Boiler No. 2 is not considered a modification in accordance with 40 CFR Part 60 Subpart A § 60.14(e)(5).

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 and was not modified after October 24, 1974. The shield was granted based on this justification.

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.

The source requested the permit shield from the Prevention of Significant Deterioration (PSD) review requirements (40 CFR 52.21, incorporated into Colorado Regulation No. 3, Part B, Section IV.D.3). The source's justification in the permit application states that this requirement is not applicable as this facility was 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 that August 7, 1977 and therefore the Division cannot grant the permit shield the PSD review requirements.

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

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

- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Section IV.A, B & H), streamlined out since Acid Rain COM/CEM requirements (40 CFR Part 75) are more stringent. Note that the calibration requirements (for COM only) in Reg 1, Section IV.F and the excess emission reporting requirements in Reg 1, Section VI.G remain in the permit.
- Opacity continuous emission monitoring requirements (Consent

Decree, entered by the District Court on August 19, 1996, Civil Action 93-B-1749, Section VI.10), streamlined out since Acid Rain COM requirements (40 CFR Part 75) are more stringent.

- Opacity continuous emission monitoring requirements (Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Hayden Station Requirements (8/15/96), as approved by EPA at 62 FR 2305 (1/16/97), Section VI.C.VI.10), streamlined out since Acid Rain COM requirements (40 CFR Part 75) are more stringent.
- 20% opacity requirement (Reg 1, Section II.A.1), streamlined out since the 20.0% opacity requirement from the consent decree (section V.8.c.ii.(2)) is more stringent.
- 30% opacity requirement for certain operating conditions (Reg 1, Section II.A.4), streamlined out since the 30% opacity requirement from the consent decree (section V.8.c.ii.(2)) is as stringent.
- 0.1 lbs/mmBtu particulate matter emission limit (Colorado Regulation No. 1, Section III.A.1.c), streamlined out since particulate matter requirements in consent decree (section V.8.c.ii.(1)) are more stringent.
- 0.45 lbs/mmBtu NO_X on a calendar year annual average (Consent Decree, entered by the District Court on August 19, 1996, Civil Action 93-B-1749, Section V.8.b.ii.(1)), streamlined out since requirement is as stringent as the Acid Rain NO_X requirement.
    - NO_X emissions shall be monitored using a CEM (Consent Decree, entered by the District Court on August 19, 1996, Civil Action 93-B-1749, Section V.8.b.ii.(2)), streamlined out since the Acid Rain program requires NO_X emissions to be monitored by a CEM.
    - Hourly average NO_X concentrations in lbs/mmBtu shall be calculated in accordance with the requirements in 40 CFR Part 75 and hourly averages shall be used to calculate quarterly averages (Consent Decree, entered by the District Court on August 19, 1996, Civil Action 93-B-1749, Section VI.18) streamlined out since calculation is in accordance with the Acid Rain requirements which are contained in Section III of the permit.

<u>Boiler No. 2, Unit B002</u>

- Continuous Emission Monitoring Requirements (Colorado Regulation No. 1, Section IV.A, B, F, G & H), streamlined out since Acid Rain COM/CEM requirements (40 CFR Part 75) are more stringent.
- Opacity continuous emission monitoring requirements (Consent Decree, entered by the District Court on August 19, 1996, Civil Action 93-B-1749, Section VI.10), streamlined out since Acid Rain

COM requirements (40 CFR Part 75) are more stringent.

- Opacity continuous emission monitoring requirements (Long-Term Strategy Review and Revision of Colorado's State Implementation Plan for Class I Visibility Protection Part I: Hayden Station Requirements (8/15/96), as approved by EPA at 62 FR 2305 (1/16/97), Section VI.C.VI.10), streamlined out since Acid Rain COM requirements (40 CFR Part 75) are more stringent.
- Continuous Emission Monitoring Requirements (40 CFR Part 60 Subpart D §§ 60.45(a), (c), (e) & (f) - install CEMs/COM, performance evaluation & calibration checks and data conversion procedures), streamlined out since Acid Rain COM/CEM requirements (40 CFR Part 75) are more stringent. Note that the excess emission reporting requirements in 40 CFR Part 60 Subpart D § 60.45(g) remain in the permit.
- Continuous Emission Monitoring Requirements (40 CFR Part 60 Subpart A §§ 60.13 <u>for the CEMs only</u>, not the COM, 40 CFR Part 60, Appendix B, <u>for CEMs only</u>, not the COM, and 40 CFR Part 60 Subpart F), streamlined out since Acid Rain COM/CEM requirements are more stringent. Note that the requirements in 40 CFR Part 60 Subpart A § 60.13 and 40 CFR Part 60 Appendix B remain in the permit for the COM. Also note that the excess emission reporting requirements in 40 CFR Part 60 Subpart A §§ 60.7 (c) and (d) remain in the permit.
- 20% opacity requirement (Reg 1, Section II.A.1), streamlined out since the 20.0% opacity requirement from the consent decree (section V.8.c.ii.(2)) is more stringent.
- 30% opacity requirement for special conditions (Reg 1, Section II.A.4), streamlined out since the 30% opacity requirement from the consent decree (section V.8.c.ii.(2)) is as stringent.
- 0.1 lbs/mmBtu particulate matter emission limit (Colorado Regulation No. 1, Section III.A.1.c), streamlined out since particulate matter requirements in consent decree (section V.8.c.ii.(1)) are more stringent.
- 0.1 lbs/mmBtu particulate matter emission limit (40 CFR Part 60 Subpart D § 60.42(a)(1), as adopted by reference in Colorado Regulation No. 6, Part A), streamlined out since particulate matter requirements in consent decree (section V.8.c.ii.(1)) are more stringent.
- 1.2 lbs/mmBtu SO_2 emission limit (40 CFR Part 60 Subpart D § 60.43(a)(2), as adopted by reference in Colorado Regulation No. 6, Part A), streamlined out since Reg 1 SO_2 requirements are more stringent.
- Opacity exemption (40 CFR Part 60 Subpart A § 60.11(c)) since other opacity requirements (i.e. consent decree requirements) do not have this exemption.
- 0.50 lbs/mmBtu NO_X on a calendar year annual average (Consent

Decree, entered by the District Court on August 19, 1996, Civil Action 93-B-1749, Section V.8.b.ii.(2)), streamlined out since requirement is as stringent as the Acid Rain NO_X requirement.

- o NO_X emissions shall be monitored using a CEM (Consent Decree, entered by the District Court on August 19, 1996, Civil Action 93-B-1749, Section V.8.b.ii.(2)), streamlined out since the Acid Rain program requires NO_X emissions to be monitored by a CEM.
- o Hourly average NO_X concentrations in lbs/mmBtu shall be calculated in accordance with the requirements in 40 CFR Part 75 and hourly averages shall be used to calculate quarterly averages (Consent Decree, entered by the District Court on August 19, 1996, Civil Action 93-B-1749, Section VI.18) streamlined out since calculation is in accordance with the Acid Rain requirements which are contained in Section III of the permit.

Consent Decree Requirements

The consent decree requirements apply to both boilers No. 1 and 2. As specified previously in this document, Colorado's Visibility SIP was revised to incorporate the requirements from the Hayden consent decree that relate to visibility impairment (SO_2 and opacity). Therefore, the consent decree requirements were streamlined out of the permit in favor of the Visibility SIP requirements. The following consent decree requirements are affected by this streamlining.

- Definitions of boiler operating day (Section II.2.b) and rolling average basis (Section II.2.x) streamlined out since Visibility SIP Sections VI.C.II.2.b & x are as stringent.
- Maintain and optimally operate the boilers and all pollution control equipment (Section V.7) streamlined out since Visibility SIP Section VI.C.V.7 is as stringent.
- 0.160 lbs/mmBtu SO_2 on a 30 boiler operating day rolling average basis (Section V.8.a.ii.(1)) streamlined out since Visibility SIP Section VI.C.V.8.a.ii(1) is as stringent.
- 0.130 lbs/mmBtu SO_2 on a 90 boiler operating day rolling average basis (Section V.8.a.ii.(2)) streamlined out since Visibility SIP Section VI.C.V.8.a.ii(2) is as stringent.
- Monitoring SO_2 emissions using CEMs (Section V.8.a.iii & v) streamlined out since Visibility SIP Sections VI.C.V.8.a.iii & v are as stringent.
- 82% reduction of SO_2 emissions, on a 30 boiler operating day rolling average basis (Section V.8.a.iv) streamlined out since Visibility SIP Section VI.C.V.8.a.iv is as stringent.
- Data exclusions from daily SO_2 emissions (Sections V.8.a.vi & viii) and catastrophic failure requirements (Section V.8.a.ix) streamlined

out since Visibility SIP Section VI.C.V.8.a.vi, viii & ix are as stringent.

- Requirements for operating SO_2 control system (Section V.8.a.vii) streamlined out since Visibility SIP Section VI.C.V.8.a.vii is as stringent.
- 0.03 lbs/mmBtu, as averaged over six (6) hours of EPA's reference method for particulate testing (Section V.8.c.ii.(1)) streamlined out since Visibility SIP Section VI.C.V.8.c.i.(1) is as stringent.
- Opacity of 20.0%, as averaged over each separate 6-minute period within an hour, beginning each hour on the hour (Section V.8.c.ii.(2)) streamlined out since Visibility SIP Section VI.C.V.8.c.ii.(2) is as stringent.
- Notwithstanding the above, during periods of building a new fire, cleaning of fire boxes, startup, soot blowing, any process modification or adjustment or occasional cleaning of control equipment, opacity shall not exceed 30% for a period or periods aggregating more than 6 minutes in any 60 consecutive minutes (Section V.8.c.ii.(2)) streamlined out since Visibility SIP Section VI.C.V.8.c.ii.(2) is as stringent.
- Excusing of opacity readings in excess of limitations (Section V.8.c.iii) streamlined out since Visibility SIP Section VI.C.V.8.c.iii is as stringent.
- Compliance with the opacity limits shall be monitored using the COM (Section V.8.c.v) streamlined out since Visibility SIP Section VI.C.V.8.c.v is as stringent.
- Maintain, calibrate and operate CEMS to measure accurately SO_2 and NO_X emissions from each unit, as well as CO_2 and flow, in full compliance with the requirements in 40 CFR Part 75 (Section VI.9) streamlined out since Visibility SIP Section VI.C.VI.9 is as stringent. **Note that the Visibility SIP does not require installation of a NO_X CEM but the Acid Rain Program requires a CEM for measuring NO_X emissions, so the requirement to monitor NO_X emissions has been subsumed by the requirements in 40 CFR Part 75.**
- Install, maintain, operate and calibrate an accurate CEMS at the inlet flue gas stream to the lime spray dryer on each unit to measure accurately SO_2 concentrations in lbs/mmBtu (Section VI.12.(a)) streamlined out since Visibility SIP Section VI.C.VI.12.(a) is as stringent.
- Tie the coal feeders for each unit into the SO_2 CEMs such that the CEMs accurately reflect the date and time when the first coal feeder on each unit has started during each startup (Section VI.12.(b)) streamlined out since Visibility SIP Section VI.C.VI.12.(b) is as stringent.
- Hourly average SO_2 concentrations, in lbs/mmBtu, shall be calculated at the inlet and outlet continuous emission monitors for

each unit, in accordance with the requirements of 40 CFR Part 75 (Section VI.16) streamlined out since Visibility SIP Section VI.C.VI.16 is as stringent.

- Hourly SO_2 percent removal, daily SO_2 average percentage removal and 30 day rolling average SO_2 percent removal (Section VI.16.a) streamlined out since Visibility SIP Section VI.C.VI.16.a is as stringent.
- Daily average SO_2 emissions and 30 day and 90 day rolling averages (Section VI.16.b) streamlined out since Visibility SIP Section VI.C.VI.16.b is as stringent.
- First 2 hrs after first coal feeder has started can be excluded (Section VI.16.c) streamlined out since Visibility SIP Section VI.C.VI.16.c is as stringent.
- Quarterly excess emission reporting for SO_2 30 and 90 day rolling averages (Section VI.17) streamlined out since Visibility SIP Section VI.C.VI.17 is as stringent.
- Quarterly excess emission reporting for the opacity standards (Section VI.22) streamlined out since Visibility SIP Section VI.C.VI.22 is as stringent.
- The opacity CEMS on Units 1 and 2 shall be properly recording data at least 98% of each unit's operating time each quarter (Section VI.23) streamlined out since Visibility SIP Section VI.C.VI.23 is as stringent.
- For any hour that valid, quality-assured continuous emission monitor data is unavailable, SO_2 and NO_X emissions shall be replaced according to 40 CFR Part 75 (Section VI.20) streamlined out since Visibility SIP Section VI.C.VI.20 is as stringent. **Note that the Visibility SIP does not require the replacement of NO_X data but the Acid Rain Program does require data replacement for the NO_X limits, so the requirement to replace NO_X data has been subsumed by the requirements in 40 CFR Part 75.**
- Calculate opacity based on CEM data for each six-minute period (Section VI.21) streamlined out since Visibility SIP Section VI.C.VI.21 is as stringent.

VII. Acid Rain Provisions

Units No. 1 and No. 2 (identified as B001 and B002 in the Title V permit application and this document) 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). Unit No. 1 is subject to NO_X emission limits of 0.46 lbs/mmBtu, on an annual average basis, per § 76.7(a)(2) and Unit No. 2 is subject to NO_X emission limits of 0.40 lbs/mmBtu, on an annual average basis, per § 76.7(a)(1).

As an affected unit under the Acid Rain Program, Units No. 1 and No. 2 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, opacity and diluent gas. The source submitted the continuous emission monitoring (CEM) certification package on January 1, 1995.