TECHNICAL REVIEW DOCUMENT for OPERATING PERMIT 960PDE134

to be issued to:

Public Service Company - Zuni Station
Denver County
Source ID 0310007

Prepared on February 6, 1997 Revised on February 6, March 17, and June 12, 1998 Jacqueline Joyce, Review Engineer

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 this report are based on information provided in the original application submittal of February 15, 1996, additional technical information submitted November 15, 1996, Public Service's comments on the Technical Review Document and draft Operating Permit submitted March 16, 1998 and comments made during the EPA review period submitted on June 11, 1998 and telephone conversations with the source. Note that although changes were made to this permit during the EPA 45-day review period, the changes did not require this permit to go through another Public Comment period as the changes in monitoring were more stringent and accurate than the previous monitoring requirements. The monitoring changes require the use of the Continuous Monitoring System (CMS) that is required by 40 CFR Part 75 to demonstrate compliance with the Acid Rain requirements. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

II. Source Description:

This source is classified as an electric services facility under Standard Industrial Classification 4911. This facility consists of three steam boilers (Units 1A, 1B, & 2) that are fueled primarily by natural gas, although No. 6 fuel oil is used as a back-up fuel. Typically these boilers provide steam to the downtown Denver area, however, during peak operating periods the turbines are brought on line. Boilers 1A and 1B serve a common turbine that is rated at 45 MW and boiler 2 supports a turbine rated at 76 MW. This facility is located in central Denver at 1335 Zuni Street in Denver county. This facility is located in an area that is designated as nonattainment for Carbon Monoxide, PM₁₀ and Ozone. Rocky Mountain National Park and Eagles Nest Wilderness Area, both Federal Class I

designated areas are within 100 km of this facility. There are no affected states within 50 miles of this facility. This facility is a major source for the purposes of nonattainment area New Source Review (NSR), however, it was constructed prior to the adoption of NSR regulations and the implementation of lowest achievable emission rate (LAER). No major modifications have been undertaken to trigger additional NSR or LAER review. Emissions at the facility are as follows:

<u>Pollutant</u>	Potential to Emit (tpy) (100% Natural Gas)	Potential to Emit (tpy) (100% #6 Fuel Oil)	Actuals (tpy) Combination)
PM	22.5	539	1.1
PM_{10}	22.5	158	1.1
SO ₂	5	6,612	~0
NO _x	4,156	3,470	196
VOĈ	12.9	38.5	0.6
CO	302	257	14.3
HAP	N/A	18.4	0.05

Potential to emit is based on information supplied in the Title V application for regulated units. Actual emissions are based on the latest Air Pollution Emission Notice (APEN) submitted for each piece of equipment, which were submitted with the Title V permit application. Hazardous Air Pollutant (HAP) emissions, both potential to emit and actual are based on APENs submitted September 30, 1996, using 1995 data, as a result of the Division's request for electric utilities to submit HAP addendums (APENs) on their boilers. This source indicated that this facility is not subject to the 112(r) Accidental Release Requirements. The boilers at this facility are affected units and are subject to the Title IV Acid Rain provisions.

III. Emission Sources:

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

- A. Unit B001: Babcock and Wilcox Boiler, Unit # 1A, Model Number Unknown, Serial No. 15253, Rated at 450 mmBtu/hr. Natural Gas Fired with No. 6 Fuel Oil for Back-up.
 - 1. Applicable Requirements This unit was first placed in service and/or last modified in August 1948. This unit was issued a "permit to operate", P20-092 and neither the source or the Division has been able to locate a copy of this permit. The "permit to operate" was issued under Regulation 3 (as adopted December 9, 1971 and effective February 1, 1972), which required that "permits to operate" be renewed every 2 years. This permit, P20-092 had an expiration date.

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

Although this permit cannot be located, the Division is confident, based on a review of other permits issued around that time, that the permit did not contain any applicable requirements beyond the typical Regulation 1 opacity, particulate and SO₂ requirements. Therefore the Division has identified, based on current regulations, the following applicable requirements for this unit:

- Opacity shall not exceed 20% during normal operations (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 of control equipment (Reg 1, Section II. A.4)
- Particulate emissions shall not exceed the following (Reg 1, Section III.A.1.b):

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

Where: PE = particulate emissions (lbs/mmBtu)

FI = fuel input (mmBtu/hr)

For the permit, the manufacturer's maximum design heat input (FI) was used to calculate the particulate emissions limit.

- Either a continuous emission monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained and operated or a Division approved sampling plan shall be developed and implemented for determining the amount of sulfur in the fuel in order to calculate sulfur oxide emissions (Reg 1, Section IV.B.2).
- When burning No. 6 fuel oil, Sulfur Dioxide emissions shall not exceed 0.8 lbs/mmBtu (Reg 1, Section VI.A.3.b.(ii)).
- Restrictions on the use of oil as back-up fuel which include reporting and recordkeeping requirements as well as restricting use of oil during certain time periods (Reg 1, Section VIII).
- APEN reporting (Reg 3, Part A Section II)
- Acid Rain requirements as follows:
 - This unit currently holds 338 SO₂ allowances (as listed in 40 CFR 73.10(b)). Therefore SO₂ emissions shall not exceed 338 tons/yr, unless additional allowances can be obtained as needed per 40 CFR Part 73.
 - Since this unit is not a coal-fired boiler, it has no NO_x limitations under 40 CFR Part 76.
 - 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 emissions (40 CFR Part 77).

2. Emission Factors - Emissions from these boilers result from combustion of fossil fuels. Type and quantities of emissions are dependent on the fuels being burned. This unit primarily burns natural gas and No. 6 fuel oil is utilized as a back-up. The pollutants of concern are Particulate Matter (PM and PM₁₀), Nitrogen Oxides (NO_x), Sulfur Dioxide (SO₂), Carbon Monoxide (CO), and Volatile Organic Compounds (VOC). Some hazardous air pollutants (HAPs) are generated through the combustion process primarily with the combustion of No. 6 fuel oil. 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) dated January 1995, Section 1.3 (for fuel oil consumption) and Section 1.4 (for natural gas consumption).

<u>Pollutant</u>	Emission Factor - Natural Gas (Ibs/mmCF)	Emission Factor - No. 6 Fuel Oil (lbs/10 ³ gal)
PM	3.0	9.19S + 3.22
PM_{10}	3.0	0.71 (9.19S + 3.22)
SO ₂	0.60	157S + 5.7S
NO_x	550	67
CO	40	5
VOC	1.7	0.76

In the identified emission factors, "S" represents the weight percent of sulfur in the fuel.

3. Monitoring Plan - Compliance demonstration and monitoring requirements for this unit are identified in sections 1 - 3 of Section II of the permit. Conditions 1.1 through 1.6 cover natural gas fuel, Conditions 2.1 through 2.10 cover No. 6 fuel oil, and Conditions 3.1 through 3.10 cover a combination of fuels.

Monitoring requirements for natural gas consist of maintaining records of annual fuel usage and an annual emissions calculation. Note that annual emissions of SO_2 and NO_X are determined by the continuous monitoring system (CMS) required by 40 CFR Part 75. Compliance with particulate requirements are presumed through use of pipeline quality natural gas. Typically, the Division presumes that compliance with the opacity requirements are met when burning natural gas as fuel. However, since the Division read an opacity violation (32 % on November 18, 1997) on one of the boilers at Zuni, when burning natural gas, and both state and local inspectors have seen visible emissions at the facility, the Division believes that periodic monitoring for opacity is necessary. Periodic monitoring will consist of recording any instance of visible emissions and performing an emission observation in accordance with EPA Reference Method 9 is visible emissions persist for longer than 15 minutes.

Monitoring requirements for No. 6 fuel oil are based on sampling of fuel oil for sulfur and heat content as well as quarterly recordkeeping requirements regarding fuel usage. An annual emissions estimate is required to demonstrate compliance with APEN reporting. Note that annual emissions of SO_2 and NO_X are determined by the CMS. Compliance with the particulate standard is based on calculation using the average heat content of the fuel from fuel sampling. Compliance with the sulfur dioxide requirement is demonstrated using the CMS required by 40 CFR Part 75. The SO_2 emissions as determined by the CMS are divided by the heat input into the boiler as determined by the CMS. Compliance with the opacity standard is demonstrated using EPA method 9.

Using a combination of fuels this unit must essentially demonstrate compliance per the monitoring plan identified for No. 6 fuel oil.

- **4. Compliance Status -** The source certified that they were in compliance with all applicable requirements. Revised APENs were submitted with the permit application. The Division concurs that the source is currently in compliance with all applicable requirements.
- B. Unit B002: Babcock and Wilcox Boiler, Unit # 1B, Model Number Unknown, Serial No. 15265, Rated at 200 mmBtu/hr. Natural Gas Fired with No. 6 Fuel Oil for Back-up.
 - **1. Applicable Requirements -** This unit was first placed into service and/or last modified in August 1948. This unit was also issued a "permit to operate", P20-092. See discussion under B001 for more information on this permit.

This unit is subject to the following specific applicable requirements:

- Opacity shall not exceed 20% during normal operations (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 of control equipment (Reg 1, Section II. A.4)
- Particulate emissions shall not exceed the following (Reg 1, Section III.A.1.b):

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

Where: PE = particulate emissions (lbs/mmBtu)

FI = fuel input (mmBtu/hr)

For the permit, the manufacturer's maximum design heat input (FI) was used to calculate the particulate emissions limit.

- When burning No. 6 fuel oil, Sulfur Dioxide emissions shall not exceed 1.5 lbs/mmBtu (Reg 1, Section VI.A.3.b.(i)).
- Restrictions on the use of oil as back-up fuel which include reporting and recordkeeping requirements as well as restricting use of oil during certain

- time periods (Reg 1, Section VIII).
- APEN reporting (Reg 3, Part A Section II)
- Acid Rain requirements as follows:
 - This unit currently holds zero (0) SO₂ allowances (as listed in 40 CFR 73.10(b)). Therefore this unit shall not emit any SO₂, unless additional allowances can be obtained as needed per 40 CFR Part 73.
 - Since this unit is not a coal-fired boiler, it has no NO_x limitations under 40 CFR Part 76.
 - 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 emissions (40 CFR Part 77).
- **2. Emission Factors -** The same emission factors will be used for this unit as used for Unit B001. For specific information see the discussion on Emission Factors for Unit B001.
- **3. Monitoring Plan -** Compliance demonstration and monitoring requirements for this unit are identified in sections 4 6 of Section II of the permit. Conditions 4.1 through 4.6 cover natural gas fuel, Conditions 5.1 through 5.9 cover No. 6 fuel oil, and Conditions 6.1 through 6.9 cover a combination of fuels.

For more details on specific monitoring requirements see the discussion on Monitoring Plan for Unit B001.

- **4. Compliance Status -** The source certified that they were in compliance with all applicable requirements. Revised APENs were submitted with the permit application. The Division concurs that the source is currently in compliance with all applicable requirements.
- C. Unit B003: Babcock and Wilcox Boiler, Unit # 2, Model Number Unknown, Serial No. 17869, Rated at 1,075 mmBtu/hr. Natural Gas Fired with No. 6 Fuel Oil for Back-up.
 - **1. Applicable Requirements -** This unit was first placed in service and/or last modified in June 1954. This unit is a grandfathered source.

As a grandfathered source this unit is subject to the following specific applicable requirements:

- Opacity shall not exceed 20% during normal operations (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 of control equipment (Reg 1, Section II. A.4)
- Particulate emissions shall not exceed the following: 0.1 lbs/mmBtu (Reg 1, Section III.A.1.b)
- Either a continuous emission monitoring system for the measurement of sulfur dioxide shall be installed, calibrated, maintained and operated or a Division approved sampling plan shall be developed and implemented for determining the amount of sulfur in the fuel in order to calculate sulfur oxide emissions (Reg 1, Section IV.B.2).
- When burning No. 6 fuel oil, Sulfur Dioxide emissions shall not exceed 0.8 lbs/mmBtu (Reg 1, Section VI.A.3.b.(ii))
- Restrictions on the use of oil as back-up fuel which include reporting and recordkeeping requirements as well as restricting use of oil during certain time periods (Reg 1, Section VIII).
- APEN reporting (Reg 3, Part A Section II)
- Acid Rain requirements as follows:
 - This unit currently has 5 SO₂ allowances (as listed in 40 CFR 73.10(b)). Therefore SO₂ emissions shall not exceed 5 tons/yr, unless additional allowances can be obtained as needed per 40 CFR Part 73.
 - Since this unit is not a coal-fired boiler, it has no NO_x limitations under 40 CFR Part 76.
 - 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 emissions (40 CFR Part 77).
- **2. Emission Factors -** The same emission factors will be used for this unit as used for Unit B001. For specific information see the discussion on Emission Factors for Unit B001.
- **3. Monitoring Plan -** Compliance demonstration and monitoring requirements for this unit are identified in sections 7 9 of Section II of the permit. Conditions 7.1 through 7.6 cover natural gas fuel, Conditions 8.1 through 8.10 cover No. 6 fuel oil, and Conditions 9.1 through 9.10 cover a combination of fuels.

For more details on specific monitoring requirements see the discussion on Monitoring Plan for Unit B001.

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

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

- 1. Applicable Requirements The solvent vats are subject to work practice standards identified in Regulation No. 7, Subsection X.B. These units meet the requirements of Regulation No. 3, Part A, Section II.D.4.b.(vi) for small remote reservoir cold solvent degreasers and are therefore APEN exempt. Although these units are APEN exempt they are still subject to the requirements of Regulation No. 7, Section X.B. Therefore, these units have been included in the operating permit.
- **2. Emission Factors -** Since these units are exempt from APEN reporting requirements, no emission calculations are necessary for these units.
- **3. Monitoring Plan -** Because these units meet the requirements of Regulation No. 3, Part A, Section II.D.4.b.(vi) these units are in compliance with the requirements of Regulation No. 7, Section X.B by design. Annual certification by the Responsible Official that these units have not been modified is adequate to demonstrate compliance with the applicable requirements for these units.
- **4. Compliance Status -**. The source has indicated that these units meet the requirements of Regulation No. 3, Part A, Section II.D.4.b.(vi) and therefore meet the requirements of Regulation No. 7, Section X.B by design. As a result, these units are in compliance with all applicable requirements.

IV. Insignificant Activities:

General categories of insignificant activities include: in-house experimental or laboratory equipment, chemical storage tanks less than 500 gal, landscaping and site housekeeping devices (<10 hp), chemical storage areas with capacity less than 5,000 gal, storage tanks less than 60,000 gal (butane, propane or LPG), tanks less than 40,000 gal (lubricating oil), tanks with annual throughput less than 400,000 gal per year, fuel burning equipment (< 10 mmBtu/hr) used for heating, stationary internal combustion engines, and sources with emissions less than the APEN de minimis. Specific insignificant activities identified in the Title V permit application are:

Units with emissions less than the APEN de minimis (Reg 3 Part C.II.E.3.a)

Cooling towers #1, #2, & #3 (PM emissions < 1 tpy)
Fugitive emissions from paved/unpaved roads (emissions < 1 tpy)
Venting of natural gas and VOC emissions from equipment leaks (emissions < 1 tpy)

Air conditioning or ventilation systems not designed to remove air pollutants (Reg 3 Part C.II.E.3.c)

Plant air conditioning and ventilation syste	Plant	air	air conditioning	and	ventilation	systen
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In-house experimental/laboratory equipment (Reg 3 Part C.II.E.3.i)

Plant laboratory

Brazing, soldering or welding operations, except those using lead (Reg 3 Part C.II.E.3.r)

Maintenance welding machine

<u>Landscaping/housekeeping equipment < 10 hp (Reg 3 Part C.II.E.3.bb)</u>

Mowers, snowblowers, etc..

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

Landscaping activities

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

Chemical storage areas

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

Cleaners, products, etc...

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

Restrooms, copiers, etc...

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

One (1) No. 2 diesel oil tank (500 gal)

Three (3) No. 6 fuel oil storage tanks (4,000,000 gal each)

One (1) No. 6 fuel oil storage tanks (300,000 gal)

One (1) No. 6 fuel oil day tank (3,000 gal)

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

Portable gasoline generator (<50 hp)

Gasoline pump (< 50 hp)

Emergency diesel generator (< 1,840 hp and runs < 100 hrs/yr)

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 Title V permitting requirements. Therefore, emissions from mobile sources are not identified in the draft permit as an insignificant activity.

V. Alternate Operating Scenarios:

A. Alternate Fuels

The primary fuel used in the boilers is natural gas. However, the source requested that they be permitted to use either natural gas, No. 6 fuel oil, or a combination of both. Typically the No. 6 fuel oil is for back-up purposes and natural gas is the primary fuel. Because the source is located in Denver County, they are not allowed to burn No. 6 fuel oil from November 1 through March 1 (Regulation 1, Section VIII.B), except under the following circumstances: natural gas curtailment, testing and training or equipment malfunctions that make it impossible or unsafe to operate with natural gas.

B. Chemical Cleaning of Boilers

The source has also requested, in a November 15, 1996 submittal (see attached), that boiler chemical cleaning be allowed as an insignificant activity. The Division has previously indicated that this activity does not require permitting. After a boiler has been cleaned the waste cleaning solutions are evaporated in a boiler. In order to be consistent with other power plant Operating Permits and because the Division is placing some requirements on the cleaning events, the chemical cleaning of boilers is being included in the Operating Permit as an alternate operating scenario. A permit (88DE245, initial approval, September 27, 1988) for the temporary evaporation of boiler cleaning solutions was issued for a boiler at Arapahoe Station (see attached). The Division later indicated that no permit was required for this activity and that the source should request that the permit be cancelled. Although the permit has been cancelled and is no longer valid, it was used as a guide to identify reporting and operating requirements for the alternate operating scenario of evaporating chemical cleaning solutions in the boilers. The following requirements from Permit 88DE245 were included in the Operating Permit: prior notification of the cleaning event, including the amounts and types of cleaning solutions to be evaporated as well as the evaporation rate and operation of any air pollution control equipment during evaporation of the cleaning solutions. Permit 88DE245 also indicated that the source was subject to the requirements of Regulation No. 8, Section IV and VI, which limit ambient impacts of mercury and lead. Since these boilers burn primarily natural gas with No. 6 fuel oil as a back-up, the Division does not believe that there will be significant emissions of either lead or mercury so this requirement has not been included in the Operating Permit.

VI. Permit Shield

The source identified and justified a short list of nonapplicable requirements that they wish to be specifically shielded from. The nonapplicable requirements that the source will be shielded from are as follows:

- A. Colorado Regulation 6, Part B, Section II (Standards of Performance for New Fuel-Burning Equipment) The source did not request the shield for this applicable requirement; however, the Division added this one to be consistent with other nonapplicable requirements the source identified for this facility. The permit shield was granted because these regulations are not applicable to this facility since the boilers commenced operation and were last modified well before January 30, 1979.
- 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) are not applicable to the facility as the boilers commenced operation and were last modified well before August 17, 1971. The permit shield was granted based on the source's justification.
- C. Prevention of Significant Deterioration requirements 40 CFR 52.21 (Colorado Regulation 3, Part B, Section IV.D.3) The justification in the permit application states that this requirement is not applicable as the boilers were constructed before 1971. The permit application also indicates that no modifications to the boilers have occurred since well before 1971.

The justification included in the Title V application is not entirely correct. The source is located in a nonattainment area for PM_{10} , CO and ozone. Therefore emissions of PM_{10} , CO and VOC are not subject to PSD requirements but are subject to major nonattainment area NSR review. NO_{χ} and SO_{2} are considered pre-cursors to PM_{10} and therefore are also subject to major nonattainment area NSR review. NO_{χ} and SO_{2} are also subject to PSD review; however, since the major nonattainment area NSR threshold (100 tpy) and requirements (LAER) are more stringent than PSD threshold (250 tpy) and requirements (BACT), any major modifications would be processed using the major nonattainment area NSR procedures. The permit shield was granted for these reasons.

The source also requested the permit shield for Colorado Regulation 8, Part B (40 CFR Part 61 Subpart M) from Asbestos requirements. The justification provided in the permit application stated that "all asbestos containing materials have been and will be handled in accordance with these standards." This implies that the facility still has asbestos and therefore Colorado Regulation 8, Part B still applies to this facility. The permit shield cannot be granted for this requirement.

In addition, the source also requested the permit shield for Colorado Regulation

15 (Ozone Depleting Compounds). The justification provided in the permit application stated that "all ozone depleting compounds have been and will be handled, recycled and disposed of in accordance with these standards." This implies that the facility does have ozone depleting compounds present at the facility and therefore Colorado Regulation 15 still applies to this facility. The permit shield cannot be granted for this requirement.

VII. Acid Rain Provisions

This source is an affected unit under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78. This facility is listed under 40 CFR 73.10(b)(2) with SO_2 allowances (1 ton per year of SO_2) of 338, 0 and 5 for Boilers 1A, 1B and 2 respectively. As such the source is required to have provisions for the Acid Rain requirements in its Title V permit.

Since these units burn natural gas and No. 6 fuel oil and are operated to produce electricity only at peak periods the facility can take alternate monitoring requirements and has elected to do so. The source is not required to have an SO_2 continuous emission monitoring system since the boilers meet the definition of gas-fired units as identified in §72.2 but will be required to determine SO_2 emissions in accordance with Part 75 Appendix D. The source is also not required to have a NO_x continuous emission monitoring system since the boilers meet the definition of gas-fired peaking units as identified in §72.2 but will be required to determine NO_x emissions in accordance with Part 75 Appendix E. Finally since the boilers at this facility meet the definition of gas-fired units (§72.2) they are not required to have continuous opacity monitors.

Certification of the CEMs and/or alternate monitoring must be approved by EPA. The source has submitted Certification Application forms and Monitoring Plans for SO_2 and NO_X to the EPA. The EPA sent a letter to the source on October 10, 1997, indicating that the Certification Application was incomplete. The EPA identified the missing information and requested that the source provide that information. Public Service Company submitted the missing information to the EPA on November 19, 1997. At this time the EPA has not certified the CEMs for Zuni Station. In the event that the CEMs cannot be certified the appropriate action will be taken by the Division and the permit will be modified as necessary.