TECHNICAL REVIEW DOCUMENT
For
RENEWAL OF OPERATING PERMIT 97OPWE180

Public Service Company – Ft. St. Vrain Station
Weld County
Source ID 1230023

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August 2004
Revised November 3, 2004 and March 2005
Revised April 6, 2005 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 by the renewed operating permit proposed for this site. The original Operating Permit was issued January 1, 2000 and expires on January 1, 2005. This document is designed for reference during the review of the proposed permit by the EPA, the public, and other interested parties. The conclusions made in this report are based on information provided in the renewal application submitted October 21, 2003, comments on the draft renewal permit and technical review document received on December 2, 2004, additional information submittals on February 10 & 11 and March 1 & 8, 2005, previous inspection reports and various e-mail correspondence, as well as telephone conversations with the applicant. Please note that copies of the Technical Review Document for the original permit and any Technical Review Documents associated with subsequent modifications of the original Operating Permit may be found in the Division files as well as on the Division website at http://www.cdphe.state.co.us/ap/Titlev.html.

Any revisions made to the underlying construction permits associated with this facility made in conjunction with the processing of this operating permit application have been reviewed in accordance with the requirements of Regulation No. 3, Part B, Construction Permits, and have been found to meet all applicable substantive and procedural requirements. This operating permit incorporates and shall be considered to be a combined construction/operating permit for any such revision, and the permittee shall be allowed to operate under the revised conditions upon issuance of this operating permit without applying for a revision to this permit or for an additional or revised construction permit.

II. Description of Source

This facility classified as an electric services facility under Standard Industrial Classification 4911. This facility consists of three (3) natural gas fired combustion turbines and three (3) heat recovery steam generators (HRSG). The capacity of the steam turbine is 330 megawatts (MW). The output rating of the entire plant varies based on ambient temperature with more generation in the winter and less generation in

the summer. The facility generates approximately 737 MW (summer rating) of electricity. **The turbines are numbered as follows: T001 (turbine No.1) is the steam generator, T002 (turbine No. 2) is the No. 1 combustion turbine, T003 (turbine No. 3) is the No. 2 combustion turbine and T004 (turbine No. 4) is the No. 3 combustion turbine.** Combustion turbines 2 and 3 each generate approximately 135 MW of electricity and each HSRG, which includes duct burners for supplemental firing, will add approximately 100 MW of electrical capacity. Combustion turbine 4, which commenced operation in April 2001, generates approximately 141.7 MW of electricity and the HRSG, which includes a duct burner for supplemental firing, will add approximately 100 MW of electrical capacity. These combustion turbines and HRSG combinations can be run in three modes: simple cycle (combustion turbine only), combined cycle (combustion turbine with HRSG) with no fuel fired in the duct burners and combined cycle (combustion turbine with HRSG) with fuel fired in the duct burners. In simple cycle operation, exhaust from the combustion turbine is discharged through the bypass stack. In combined cycle, the exhaust gas from the turbine passes through the HRSG first and then exits out the HRSG stack. In addition to the combustion turbines, significant emission units at this facility consist of an auxiliary boiler fueled by natural gas, one cooling water tower and one service water tower.

Based on the information available to the Division and provided by the applicant, it appears that no modifications to the significant emission units has occurred since the original issuance of the operating permit.

The facility is located approximately three miles north and west of Platteville, Colorado. The area in which the plant operates is designated as attainment for all criteria pollutants, but is located in the 8-hr Ozone Control Area as defined in the Federal Register, Volume 69, No. 84, dated April 30, 2004.

There are no affected states within 50 miles of the plant. Rocky Mountain National Park, Eagle's Nest National Wilderness Area and Rawah National Wilderness Area, Federal Class I designated areas, are within 100 kilometers of the plant.

The summary of emissions that was presented in the Technical Review Document (TRD) for the original permit issuance has been modified to more appropriately identify the potential to emit (PTE) with the addition of the third combustion turbine. Emissions (in tons/yr) at the facility are as follows:

	Potential to Emit (PTE)						
Emission Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPS
Turbine (T002)	39.4	39.4	4.7	496.1	465.4	21.4	See Table on Page 10
Turbine (T003)	39.4	39.4	4.7	496.1	465.4	21.4	
Turbine (T004)	54	54	4.7	199.1	237.9	33.1	
Auxiliary Boiler (B001)	0.6	0.6	0.2	32.6	27.4	1.8	
Cooling/Service Water Towers (M001)	14.9	14.9				2.4	

Emission Unit	Potential to Emit (PTE)						
	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPS
Total	148.3	148.3	14.3	1,223.9	1,196.1	80.1	17.48

Potential to Emit is based on permitted emission limits.

The breakdown of HAP emissions by emission unit and individual HAP is provided on page 10 of this document. HAP emissions were calculated using stack test emission factors (Unit 2 combined cycle, with fuel firing performed on June 23-26, 1998 for Units 2 and 4 and Unit 3 combined cycle, with fuel firing performed on October 5 & 6, 1999) for formaldehyde for the turbine/duct burner combination and AP-42 for the turbines, duct burners and boiler for the other pollutants, except that acetaldehyde for the turbines is based on ICCR (as indicated on source's APENS), manganese and nickel for the turbines from FIRE and hexane from the duct burners and boilers based on a May 2000 EPRI report. HAP emissions are based on the emission factors and the permitted fuel consumption or materials processing rate, except as noted at the bottom of the Table on page 10

It should be noted that the formaldehyde emission factor determined from the stack test was determined using CARB 430. In the final MACT rule for combustion turbines (published in the Federal Register on March 5, 2004), the EPA indicates that during the development of the rule, that emission factors were developed and presented in a memorandum (dated 8/22/03) and that the emission factors in that memorandum represent the most accurate emission information for stationary combustion turbines (FR, volume 69, No. 44, dated March 5, 2004, starting on pg 10517, 3rd column, last paragraph). The Division agrees with the use of formaldehyde emission factors from the performance testing of these turbines, however, the EPA memo indicates that emission estimates using CARB 430 are biased low compared to those measured by Fourier Transform Infrared Spectroscopy (FTIR). A correction factor of 1.7 was developed for the emission factors in the EPA memo and the source applied that factor to the emission factors determined from the performance tests for the Ft. St. Vrain turbines.

	Actual Emissions (tons/yr)						
Emission Unit	PM	PM_{10}	SO_2	NO_X	CO	VOC	HAPS/NCRP[1]
Turbine (T002)	29.8	29.8	3.9	210	23.9	15.2	2.28
Turbine (T003)	28.7	28.7	3.8	141.3	41.7	12.1	2.20
Turbine (T004)	29.7	29.7	3.9	72.8	34.5	13.5	14.49
Auxiliary Boiler (B001)	0.3	0.3	0.1	16	13	1	
Cooling Tower (M001)	2.1	2.1				1.8	1.8
Total	90.6	90.6	11.7	440.1	113.1	43.6	20.77

[1]NCRP = non-criteria reportable pollutants, such as ammonia

Actual emissions are based on information in the Division's 2002 inventory.

MACT Requirements

Case-by-Case MACT - 112(j) (40 CFR Part 63 Subpart B §§ 63.50 thru 63.56)

Under the federal Clean Air Act (the Act), EPA is charged with promulgating maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) in various source categories by certain dates. Section 112(j) of the Act requires that permitting authorities develop a case-by-case MACT for any major sources of HAPs in source categories for which EPA failed to promulgate a MACT standard by May 15, 2002. These provisions are commonly referred to as the "MACT hammer".

Owners or operators that could reasonably determine that they are a major source of HAPs which includes one or more stationary sources included in the source category or subcategory for which the EPA failed to promulgate a MACT standard by the section 112(j) deadline were required to submit a Part 1 application to revise the operating permit by May 15, 2002. The source submitted a notification indicating that the Ft. St. Vrain Station was a major source for HAPS, with equipment under the combustion turbine source category. Since the EPA has signed off on final rules for all of the source categories which were not promulgated by the deadline, the case-by-case MACT provisions in 112(j) no longer apply.

Other MACT Standards

As part of the renewal application review, the Division looked at HAP emissions from the facility. Apparently the source had determined their HAP major source status based on formaldehyde emissions from the turbines on AP-42 emission factors. Performance tests for Turbines 2 and 3 were conducted and indicate that formaldehyde emissions are much lower than predicted by AP-42 emission factors. The Division's initial analysis was based on the performance test emission factors for formaldehyde (for the turbines) and AP-42 emission factors for other pollutants. Our initial analysis showed that with the conservative AP-42 emission factor for hexane for natural gas-fired boilers (used to estimate duct burner and boiler emissions), that the facility was a major source of HAPS. However, in their February 11, 2005 submittal, the source proposed to use hexane emission factors from an Electric Power Research Institute (EPRI) paper (date May 2000). Therefore, based on the EPRI emission factors for hexane, the Division has determined that the facility is no longer a major source of HAPS. Therefore, no MACT standards apply to this facility.

CAM Requirements

CAM applies to any emission unit that is subject to an emission limitation, uses a control device to achieve compliance with that emission limitation and has potential pre-control emissions greater than major source levels. As discussed in the technical review document for the August 1, 2003 modification, CAM applies to Turbine 4, since it is

equipped with selective catalytic reduction to control NO_X emissions and the CAM requirements were included in the August 1, 2003 modification. Although Turbines 2 and 3 are equipped with dry low NO_X (DLN) combustion systems, DLN is not considered a control device as defined in 40 CFR Part 64 § 64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, since DLN is considered inherent process equipment. Therefore, Turbines 2 and 3 are not subject to CAM. Finally, although the cooling water and service water towers are equipped with drift eliminators, drift eliminators are not considered a control devices as defined in 40 CFR Part 64 § 64.1, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, since the drift eliminators act as a passive control measure prevent release of pollutants (i.e. drift). Therefore, only Turbine 4 is subject to the CAM requirements.

III. Discussion of Modifications Made

Source Requested Modifications

The source's requested modifications identified in the renewal application were addressed as follows:

Section II, Condition 1.2.1

The source requested that the alternative NO_X and CO BACT limits for combustion tuning be revised to include testing. As part of manufacturer's recommended procedures, certain testing must be performed on the combustion turbine and steam turbine. The source has not requested any additional time for the testing procedures. Therefore, the change will be made as requested.

In a February 10, 2005 e-mail, the source requested revisions to the combustion tuning and testing alterative BACT limits. The current definition indicates that combustion tuning and testing takes place in Mode 1-5 operation, however, changes to the manufacturer's tuning and testing program now specify that a significant amount of tuning and testing be conducted in Mode 6 operation. Therefore, the source has requested that the definition of combustion tuning and testing be revised to allow tuning to be complete throughout the entire range of combustion modes.

In addition, the source has requested that the 30-hour annual limit for tuning and testing for each turbine be revised to allow for 90 hours annually for all three turbines combined. The changes will be made as requested.

Section II, Condition 1.5.2

In a March 8, 2005 e-mail, the source noted that the description of the VOC correlation should be changed from "VOC emissions vs. load" to "VOC emissions vs. heat input". The change was made as requested.

Section II, Conditions 1.6 and 1.7

In their comments on the draft permit received on December 2, 2004, the source indicated that performance tests were conducted on Units 2 and 3 in 2004 to determine PM and PM_{10} emissions as required by the current Title V permit. The source requested that the emission factors from these tests be included in the permit to monitor compliance with the annual emission limits. Note that although the performance tests have been conducted, the Division has not reviewed and approved the tests. Based on the Division's review of the tests, changes to the emission factors may be necessary. The emission factors that will be included in the renewal permit are as follow:

Unit	Emission Factor (lb/mmBtu)		Source of Emission Factor
	PM	PM_{10}	
Unit 2 – Simple Cycle	0.006	0.006	9/27 & 28/04 performance test
Unit 2 – Combined Cycle	0.002	0.002	5/11 & 12/04 performance test
Unit 3 – Simple Cycle	0.006	0.006	9/29/04 performance test
Unit 3 – Combined Cycle	0.002	0.002	5/12 & 13/04 performance test

Section II, Condition 5.1.5

In comments received during the public comment period (e-mail received 3/22/05), the source requested that Condition 5.1.5 (monitor concentration of oxygen, percent hourly average, in the exhaust) be removed. NO_X and CO emissions from the turbines are adjusted to 15% O_2 through the measurement of CO_2. The change has been made as requested.

Appendix A – Insignificant Activities

The source indicated that diesel fueling operations should not be under the exemption for fuel storage and dispensing (Reg 3, Part C, Section II.E.3.ccc), as they thought that the exemption applied to gasoline storage and dispensing only and suggested that the diesel activities under this exemption be moved under the storage tank exemption in Reg 3, Part C, Section II.E.3.fff (annual throughput less than 400,000 gallons, limited tank contents). The Division agrees and made the change as requested.

Appendix G – Bypass Stack CEMS QA/QC Requirements

In their comments on the draft permit, submitted on December 2, 2004, the source requested that the specific language be added to specify how long the source has to conduct a linearity test or relative accuracy test audit (RATA) after a RATA is triggered. The Division made the change as requested.

Other Modifications

In addition to the source requested modifications, the Division has included changes to make the permit more consistent with recently issued permits, include comments made by EPA on other Operating Permits, as well as correct errors or omissions identified during inspections and/or discrepancies identified during review of this renewal.

The Division has made the following revisions, based on recent internal permit processing decisions and EPA comments to the Ft. St. Vrain Renewal Operating Permit. These changes are as follows:

Page Following Cover Page

Monitoring and compliance periods and report and certification due dates are shown as examples. The appropriate monitoring and compliance periods and report and certification due dates will be filled in after permit issuance and will be based on permit issuance date. Note that the source may request to keep the same monitoring and compliance periods and report and certification due dates as were provided in the original permit. However, it should be noted that with this option, depending on the permit issuance date, the first monitoring period and compliance period may be short (i.e. less than 6 months and less than 1 year).

General

- The Reg 3 citations were revised throughout the permit, as necessary, based on the recent revisions made to Reg 3.

Section I – General Activities and Summary

- Revised Condition 1.1 to indicate that the facility is located within the 8 hour ozone control area.

- In Condition 1.4, General Condition 3.g (Common Provisions, Affirmative Defense) was added as a State-only requirement.

- Removed the diesel fuel storage tank (20,000 gal, underground) from the table in Condition 6.1.

Section II.1 and 2 – Combustion Turbines

Fuel Sampling For NSPS Subpart GG

NSPS GG was revised on July 8, 2004 (Federal Register, Volume 69, No. 130). The NSPS GG revisions provide additional monitoring options for NO_X emissions and nitrogen and sulfur content monitoring that have previously been approved by EPA. The revisions specify that previously approved alternative monitoring methods for existing turbines could still be used. The revisions allow existing turbines without water injection to use continuous emission monitoring systems (CEMS) to monitor compliance with the NO_X limitations and specify that those turbines that have Part 75 CEMS approved may use those CEMS to monitor compliance with the NO_X limits. In the original Title V permit and the August 1, 2003 modification to add Unit 4, the Division had streamlined out the NSPS NO_X requirements since the BACT NO_X limits were more stringent. In addition, the NSPS GG rules in effect at the time of the original and modified Title V permits did not specify any monitoring requirements for NO_X for

turbines without water or steam injection, although monitoring of the nitrogen content of the fuel was required. The Division had streamlined out the nitrogen content monitoring from NSPS GG in favor of the CEMS. Because the NSPS GG NO_X limit was streamlined in favor of the BACT and because the NSPS GG revisions allow the use of a Part 75 CEMS to monitor compliance with the NO_X limits, the Division considers that no changes need to be made to the permit based on the NSPS GG revisions, except that the citations in the permit shield for streamlined conditions will be revised. In addition, the NSPS GG revisions indicate that no nitrogen sampling is required if credit was not taken for fuel-bound nitrogen in setting the NO_X emission limitations. Since no credit was taken for fuel-bound nitrogen for these turbines, no nitrogen sampling is required. Therefore the citations in the permit shield for streamlined conditions will be revised.

The NSPS GG limits for SO_2 were included in the original Title V permit and in the August 1, 2003 revised permit to address Unit 4. The NSPS GG requirements in effect at the time of the original and modified Title V permit required daily sulfur sampling, although a custom schedule could be approved. The Division included a requirement in the Title V permit that specifies that the gas used as fuel meets the definition of pipeline quality gas in 40 CFR Part 72 and that the demonstration be made in accordance with the provision of 40 CFR Part 75 Appendix D, Section 2.3.1.4.(a) and then streamlined the NSPS GG daily fuel sampling requirement. The NSPS GG revisions allow sources to forego fuel sampling for the sulfur content provided natural gas is used as fuel. Since the definition of pipeline quality natural gas is more stringent than the definition of natural gas and the methods to demonstrate that pipeline quality natural gas is used as fuel is the same as in the revised NSPS GG, the Division considers that no changes need to be made to the permit based on the NSPS revisions, except that the citations in the permit shield for streamlined conditions will be revised.

Acid Rain Requirements (Conditions 1.17 and 2.16)

Removed the requirement to submit a copy of the annual certification to the Division. Beginning in March 2004 (2003 compliance certification), the certifications will be an electronic certification, rather than a paper certification. The Division would consider that the annual compliance certification for the Title V permit (Appendix C) would service that the certification that the facility complied with the Acid Rain Requirements for the relevant calendar year.

<u>Section II.6 – Diesel Fuel Storage Tank</u>

The diesel storage tank was included in the August 1, 2003 revised Title V operating permit because the tank was subject to recordkeeping requirements in 40 CFR Part 60 Subpart Kb. Effective October 15, 2003, revisions were made to NSPS Subpart Kb and under these revisions tanks that have a capacity greater than 75 m^3 (19,813 gal) but less than 151 m^3 (39,889 gal) storing a liquid with a maximum true vapor pressure less than 15 kPa are exempt from the provisions of 40 CFR Part 60 Subpart Kb. Since the tank has emissions below APEN de mimims levels and since the tank is no longer

subject to 40 CFR Part 60 Subpart Kb, this tanks is no longer subject to APEN reporting requirements and can be considered an insignificant activity. Therefore, this tank has been removed from Section II of the permit and is now included in Appendix A.

Ozone Early Action Compact Requirements

The Division entered into an early action compact to delay being re-designated as a non-attainment area for the 8-hour ozone standard. The early action compact requires controls to reduce VOC emissions in the 8-hour ozone control area. The early action compact VOC control requirements have been included in Colorado Regulation No. 7 and those requirements became effective, on a state-only basis, on May 31, 2004. The VOC control requirements apply to oil and gas operations (Colorado Regulation No. 7, Section XII) and stationary internal combustion engines (Colorado Regulation No. 7, Section XVI) located in the 8-hour ozone control area. Since the facility is not involved in oil and gas operations, only the stationary internal combustion engine requirements potentially apply to this facility. The engine requirements apply to natural gas-fire engines rated at 500 hp or greater. Although there are engines listed in the insignificant activity list in Appendix A, all of those engines are diesel fuel-fired and therefore the engine control requirements do not apply.

Section III – Acid Rain Requirements

- Revised the table to include calendar years corresponding to the relevant permit term for the renewal.

- Removed the requirement to submit a copy of the annual certification to the Division. Beginning in March 2004 (2003 compliance certification), the certifications will be an electronic certification, rather than a paper certification. The Division would consider that the annual compliance certification for the Title V permit (Appendix C) would service that the certification that the facility complied with the Acid Rain Requirements for the relevant calendar year.

Section V – General Conditions

- General Condition No. 3 was revised to reflect that 3.g (affirmative defense) is state-only until approved by EPA.

Appendices

- Removed the diesel fuel storage tanks (20,000 gal, underground) from the tables in appendices B and C.

- Replaced Appendices B and C with revised Appendices.

Total HAP Emissions (tons/yr) from PSCo - Ft. St. Vrain

Emission Unit	formaldehyde	acetaldehyde	toluene	benzene	acrolein	xylene	chloroform	hexane	dichlorobenzene	nickel	cadmium	manganese	chromium	Total
Unit 2 - turbine	2.33	0.49	0.70	0.06	0.03	0.34				0.62		0.43		5.00
Unit 2 - DB			0.01	4.06E-03				8.31E-04	2.32E-03	4.06E-03	2.13E-03		2.71E-03	0.02
Unit 3 - turbine	1.48	0.55	0.78	0.07	0.04	0.38				0.69		0.48		4.48
Unit 3 - DB			0.01	4.06E-03				8.31E-04	2.32E-03	4.06E-03	2.13E-03		2.71E-03	0.02
Unit 4 - turbine	2.42	0.55	0.78	0.07	0.04	0.39				0.69		0.48		5.43
Unit 4 - DB			0.01	3.25E-03				6.66E-04	1.86E-03	3.25E-03	1.70E-03		2.17E-03	0.02
B001	0.14		0.00	6.84E-04				1.40E-04	3.91E-04	6.84E-04	3.58E-04		4.56E-04	0.14
M001							2.37							2.37
Total	6.36	1.59	2.28	0.22	0.11	1.11	2.37	2.47E-03	6.89E-03	2.01	6.31E-03	1.40	8.03E-03	17.48

Notes on Emission Calculation Methodology:

The formaldehyde emission factors for the turbines are from stack tests on Units 2 and 3, in combined cycle operation with duct burner firing. So for Unit 4 formaldehyde emissions are based on both the fuel consumption limit for the turbine and duct burner. Based on a heat content of 1020 mmBtu/mmSCF (HHV), the design heat value of the turbines in the T5 permit, both Units 2 and 3 can run for more than 8760 hrs/yr of operation based on the fuel limit in the permit. Based on the combined cycle (with suppl fuel) fuel consumption limit minus the simple cycle fuel consumption limit for Units 2 and 3 (16,090 - 12,507 = 3583), the duct burners can run only 8,121 hrs/yr (design rate and heat content of 1020 mmBtu/mmSCF).

However, the way the permit is written, the combined cycle fuel limit applies in any 12 mo period in which combined cycle operation occurs with supplemental fuel, so presumably the duct burners can run 8760 hrs/yr also. Therefore, formaldehyde emissions from Units 2 and 3 are based on the emission factor, design rate of turbine + duct burner and 8760 hrs/yr of operation.

For other pollutants for Units 2 and 3, emissions are based on design rate and 8760 hrs/yr for both turbine and duct burner, using the appropriate emission factors.

For other pollutants for Unit 4, emissions are based on allowable fuel limit and the appropriate emission factor.