TECHNICAL REVIEW DOCUMENT
OPERATING PERMIT 01OPDE237
to be issued to:

Black Hills Colorado, L.L.C.
Arapahoe Combustion Turbine Facility

Denver County
Source ID 0310008

Prepared by Cathy Rhodes
April, 2003

I. Purpose:

This document establishes 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, the Public and other interested parties. Conclusions made in this report are based on information provided by the applicant in the Title V application submitted July 31, 2001 and review of Division files. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

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. Source Description:

This facility consists of two combustion turbine generators (CTGs) configured to selectively operate in a simple-cycle mode (exhaust directly to the atmosphere) or combined-cycle mode (exhausting to Heat Recovery Steam Generators equipped with duct burners). When operated in a simple-cycle mode, each turbine has a nominal electricity production of 38 MW at maximum capacity. The combined total output of the CTGs and the addition of the steam turbine generators will be up to 130 MW at full load in a combined-cycle mode. The turbines are used to generate power during intermediate and peak periods of electrical demand and the facility is defined under Standard Industrial Classification 4911. These combustion turbines are part of the Arapahoe Combustion Turbine Facility, operated by Black Hills Colorado, LLC. The coal fired boilers are part of the “Arapahoe Power Plant” operated by Xcel Energy. A

separate Operating Permit has been issued for each operating company, however, for permitting purposes the Arapahoe Combustion Turbine Facility and the Arapahoe Power Plant are considered one facility.

The facility is located at 2601 South Platte River Drive in Denver. The Denver metro area is classified as attainment/maintenance for particulate matter less than 10 microns (PM_{10}), ozone and carbon monoxide. Under that classification, all SIP-approved requirements for $PM_{10,}$ VOC and CO will continue to apply in order to prevent backsliding under the provisions of Section 110(l) of the Federal Clean Air Act.

These turbines are located at a facility that includes one of the 28 listed sources (fossil-fuel fired steam electric plant of more than 250 million Btu per hour) and therefore, the major stationary source threshold is 100 tons/yr. This source is considered to be a major stationary source (Potential to Emit > 100 tons/year) in an attainment area. Future modifications to this facility which are in excess of significance levels as defined in Colorado Regulation No. 3, Part A, Section I.B.58, would result in a major modification and the application of PSD requirements. The Black Hills turbines are considered to be a single stationary source, along with the Public Service of Colorado Arapahoe Generating Station, although a separate operating permit was issued to Public Service of Colorado. Facility wide emissions (includes Black Hills and Public Service) and Black Hills only emissions are as follows:

Pollutant	Facility Potential to Emit (tons/yr)	Black Hills Potential to Emit[1] (tons/yr)
PM	2,081	14.90
PM_{10}	1,459	14.90
NO_X	12,482	39.0
SO_2	19,148	1.30
CO	786	90.8
VOC	58	7.6

Potential to Emit is based on maximum operation of the Public Service company units and Black Hills permitted emission limits. The facility has not begun “normal operation,” therefore actual emissions are not available.

Rocky Mountain National Park is a Federal Class I designated area within 100 kilometers of this facility. There are no affected states within 50 miles of this facility.

This facility certified within the Title V permit application they are not subject to 112(r), the Accidental Release Requirements.

III. Emission Sources:

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

<u>Units CT005 and CT006</u> - Two (2) General Electric (GE) Model LM6000 Natural Gas Fired Combustion Turbines, rated at a heat input of 328.6 MMBtu/hr (each), Serial Numbers: 191-146 (S005) and 191-145 (S006). Each turbine is equipped with water injection for NOx control during simple cycle operation, and Selective Catalytic Reduction and catalytic oxidation to control NO_X and CO emissions, respectively, during combined cycle operation. Each unit is equipped with a 5 MMBtu/hr natural gas fired inlet air preheater for use during simple and combined cycle modes, and one (1) Heat Recovery Steam Generator natural gas fired duct burner, rated at 124.7 MMBtu/hr (each) for use during combined cycle mode.

<u>Units BG005 and BG006</u> – Two (2) diesel-fired backfeed generators, each rated at 1600 kW – Used for turbine startup

<u>Unit CL007</u> - Cooling Tower

1. **Applicable Requirements -** The turbines listed above began operating in May of 2000 as simple cycle units. These units were issued Colorado Construction Permit 99DE0473. A revised construction permit was issued on June 14, 2001 to reconfigure the units to selectively operate as simple cycle or combined cycle units. The application for this permit indicated that the turbines would be able to start up in combined cycle mode in July 2002.

The due date of the first semi-annual monitoring and deviation report required by this operating permit will be more than 180 days after the initial approval construction permit 99DE0473 was issued and/or the equipment commenced operation. Therefore, under the provisions of Regulation No. 3, Part C, Section V.A.2, the Division is allowing the initial approval construction permit to continue in full force and effect and will consider the Responsible Official certification submitted with that report to serve as the demonstration required pursuant to Regulation No. 3, Part B, Section IV.H and no final approval construction permit will be issued. The appropriate provisions of the initial approval construction permit have been directly incorporated into this operating permit. The following applicable requirements have been identified for these units:

Construction Permit 99DE0473

- Visible emissions shall not exceed twenty percent (20%) opacity during normal operation of the source. During periods of startup, process modification, or adjustment of control equipment visible emissions shall not exceed 30% opacity for more than six minutes in any sixty consecutive minutes (Condition 1 and Colorado Regulation No. 1, Sections II.a.1 & 4). Note: The operating permit condition reflects the specific Regulation No. 1

language for this applicable requirement.)

- Limits total criteria pollutant emissions from turbines, duct burners, backfeed engines and inlet heaters on a quarterly basis for the first twelve months after operation under combined cycle mode commences, and on a rolling twelve month basis thereafter. The turbines have operated under combined cycle mode for more than a year, therefore the quarterly emission limits are not included in this operating permit (Condition 2)

- Limits total amount of natural gas consumed by all equipment based on the emission limits (Condition 3)

- Requires inclusion of insignificant activity emissions for determining compliance with emission limits (Condition 4)

- The turbines are subject to Regulation No. 6 - Standards of Performance for New Stationary Sources, Part A - Federal Register Regulations Adopted by Reference, Subpart GG - Standards of Performance for Stationary Gas Turbines, including but not limited to:
    - $NO_X \leq$ 389.5 ppmvd at 15% oxygen.
    - $SO_2 \leq$ 150 ppmvd at 15% oxygen.
    - When water injection is used to control NOx emissions (i.e., simple-cycle mode), fuel consumption and water-to-fuel ratio will be continuously monitored and recorded – Note: The operating permit requires use of the CEM for demonstrating compliance with the NSPS emission limit
    - Sulfur and nitrogen content of the fuel being fired in the turbines shall be monitored as specified in this Subpart GG (Note: The permittee requested, and received a waiver from nitrogen monitoring, because pipeline quality natural gas will be used as fuel. For sulfur monitoring, if little variability in sulfur content occurs during the first six months of monitoring, then sulfur monitoring can be conducted quarterly. If after at least six quarters there is still little variability in the fuel sulfur content, then sulfur monitoring can be done semi-annually. The EPA has approved ASTM D 5504-94 as a primary method for sulfur monitoring and ASTM D 5453-93 as a backup method for sulfur analysis rather than the methods set forth in Subpart GG.)
      (Condition 5a)

- The duct burners are subject to Regulation No. 6 - Standards of Performance for New Stationary Sources, Part A - Federal Register Regulations Adopted by Reference, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units, including, but not limited to:
    - NO_X emissions shall not exceed 0.20 lb/mmBtu, on a 30-day rolling average basis (§ 60.44b(a)(1)(ii)) This limit applies at all times including periods of startup, shutdown, and malfunction (60.44b(h)
    - Compliance with the NSPS requirements shall be monitored in

accordance with the requirements in 60.48b, including but not limited to the following:

- Install and operate a continuous emission monitor for NO_X (§ 60.48b(b))

(Condition 5b)

Recently, EPA made revisions, effective June 11, 2001, to NSPS Subpart Db in order to more appropriately address duct burners. These revisions provide two methods for combined cycle units (turbine plus duct burner) to demonstrate compliance with the NO_X emission limits and specify that owners or operators of duct burners are not required to install the continuous monitoring systems for NO_X emissions, watts and steam characteristics. Owners or operators of combined cycle units may demonstrate compliance with the NO_X emission limits by either conducting performance tests or using NO_X continuous emission monitors. Because this source is a synthetic minor source for PSD purposes, the permit requires the source to use the NO_X continuous emission monitoring system to monitor compliance with the NO_X emission limits. Since the permittee is required to use a CEM for synthetic minor permit monitoring, the permit requires the use of the CEM for monitoring compliance with the NSPS, for periodic monitoring purposes. Operation of the CEM will be in accordance with the Construction Permit CEM requirements.

- Performance tests shall be conducted in accordance with the requirements in § 60.46b(c). The permittee completed the required one time test.

- Reporting and recordkeeping requirements in § 60.49b

- The turbines and duct burners are also subject to the requirements in 40 CFR Part 60 Subpart A – New Source Performance Standards – General Provisions, as adopted by reference in Colorado Regulation No. 6, Part A, the following will be included in the permit (condition 10):

- The source is subject to Regulation No. 6 – Standards of Performance for New Stationary Sources, Part B – Specific Facilities and Sources, Non-Federal NSPS, II.C & D – Standards of Performance for New Fuel-Burning Equipment – Standard for Sulfur Dioxide – Combustion Turbines (Condition 6). These are **state-only requirements**.
  - SO_2 emissions shall not exceed 0.35 lbs/mmBtu.
  - Opacity of emissions shall not exceed 20%

- The source is subject to Reasonably Available Control Technology (RACT) requirements for CO and PM_{10} (Colorado Regulation No. 3, Part B, IV.D.2.d and Condition 7)

  - Catalytic oxidation to limit CO emissions to 10 ppmvd @ 15% O2

during combined cycle mode operation
    - Pipeline quality natural gas used to minimize PM10 emissions

Note: The construction permit issued for simple cycle mode included RACT requirements for simple cycle mode. The revised construction permit for selective simple cycle/combined cycle mode did not include the simple cycle RACT requirements. The operating permit includes RACT requirements for both combined cycle and simple cycle modes. RACT for simple cycle mode is as follows:

    - Good combustion practices meet the RACT requirements for CO during simple cylce mode
    - Pipeline quality natural gas used to minimize PM10 emissions

- Compliance tests for PM, VOC, formaldehyde, and NOx. Stack test data will be used to establish emission factors to be used in calculating and reporting emissions. SO2 emission rate and unit heat input shall be determined in accordance with Appendix D of 40 CFR Part 75. (Condition 8) These tests have been completed, therefore the requirement is not included in the operating permit.

- Each turbine will be equipped with:
    - Natural gas fuel flow meter
    - CEM systems for NOx and CO concentrations and O2 in accordance with 40 CFR Part 75 and Part 60, Appendix F

  (Condition 9)

  The CO concentration limit does not apply during periods of start-up, or shutdown. The Construction Permit defined “Startup” and indicated that the permit would be revised after performance tests to better define startup. The operating permit will define startup and shutdown based on the catalyst temperature or time.

  Other applicable requirements not included in 99DE0473

- Particulate matter emissions from each turbine or turbine and duct burner combination shall not exceed the limitations in Reg 1, Section III.A.1.b

- Sulfur dioxide emissions shall not exceed 0.35 lbs/mmBtu, on a 3-hour rolling average (Reg 1, Section VI.B.4.c.(ii) and VI.B.2)

- Both units are subject to the Acid Rain requirements as follows:
    - Allocated SO_2 allowances are listed in 40 CFR Part 73.10(b), however, since these are new units, no allowances were allocated. SO_2 allowances must be obtained per 40 CFR Part 73 to cover SO_2 emissions for the particular calendar year.
    - There are no NO_X emission limitations since these units are not coal-fired boilers.
    - Acid rain permitting requirements per 40 CFR Part 72.
    - Continuous emission monitoring requirements per 40 CFR Part 75.
    - This source is also subject to the sulfur dioxide allowance system

(40 CFR Part 73) and excess emissions (40 CFR Part 77).

- The emission limitations are based on emission factors in units of lbs/hour for fuel burning equipment (except for SO_2). In order to monitor compliance with emission limits, a record of the hours of operation must be maintained, therefore this requirement is included in the operating permit. Likewise, emission calculations for the cooling tower are based on the amount of cooling water flow rate and the Total Dissolved Solids (TDS) content of the water. Recordkeeping requirements for these parameters are therefore included in the operating permit. SO2 emissions are based on fuel use. The Construction Permit includes recordkeeping requirements for natural gas, but not for diesel fuel. The operating permit includes recordkeeping requirements for diesel fuel use at the backup generators.

- At the time the permittee applied for a Construction Permit, the area in which the sources were to be constructed was classified as a nonattainment area for ozone, and the sources were subject to the Reasonably Available Control Technology requirements for VOC emissions. As noted above, the area has been redesignated as attainment/maintenance, but the RACT requirement continues to apply. A review of the files shows that the preliminary analysis lists the RACT requirement as an applicable requirement and indicates that catalytic oxidation (1.7 lbs/hour) and pipeline quality natural gas represent RACT for VOCs. In addition, the following VOC RACT determination was made for a similar source during the same time period.

SOURCE	RACT DETERMINATION
Valmont Combustion Turbine Project – Simple Cycle	Good combustion practice and use of pipeline quality natural gas

It appears this requirement was inadvertently left out of the Construction Permit. The VOC RACT requirements are included in the Operating Permit.

MACT Requirements: The EPA has promulgated maximum achievable control technology (MACT) standards for major sources of hazardous air pollutants (HAPs) for Combustion Turbines. Based on the information provided by this source, the Arapahoe Turbine Facility is a major stationary source of HAPs (i.e. facility-wide potential to emit (including the Public Service Company Arapahoe Station) of greater than 10 tons per year of any single HAP or greater than 25 tons per year of all HAPs combined) for a covered source category (Combustion Turbines). However, the turbines are exempt from the promulgated MACT standard because they are “existing” turbines.

Streamlining of Applicable Requirements

<u>Recordkeeping</u>

Construction Permit 99DE0437, Condition 3 requires retention of fuel consumption records for three years. Operating permit rules require record retention for five years (as set forth in Section V, Condition 22.c of the Operating Permit), therefore the Construction Permit requirement is streamlined out.

2. **Emission Factors-** Emissions from these turbines are produced during the combustion process, and are dependent upon operating conditions and specific properties of the natural gas being burned. The pollutants of concern are Nitrogen Oxides (NO_X), Carbon Monoxide (CO), Volatile Organic Compounds (VOC) and Particulate Matter (PM and PM_{10}). Small quantities of Hazardous Air Pollutants (HAPs) are also emitted dependent upon the makeup of the fuel and combustion efficiency. Emission limits from the turbines were established using compliance test data (except for SO2). Manufacturer's data were also used to estimate emissions from the backfeed generators (except for SO_2) and the air inlet heaters. PM emissions from the cooling tower are based on the EPA's AP-42, Table 13.4.1. These factors will be used to monitor compliance with the emission limits after operation of combined cycle mode commences, except that, for the turbines and turbine/duct burner combination: CEMs will be used to monitor compliance with NOx and CO limits; and stack test data will establish/verify emission factors for PM and VOC emissions. (A compliance test was performed for VOC emissions in March of 2003. Test results were greater than 75% of the RACT emission limit, therefore testing will be repeated during the first year of the operating permit. SO_2 emissions from the turbines are based on the EPA default emission rate of 0.0006 lb/MMBtu from 40 CFR Part 75, Appendix D.2.3.2 (Acid Rain provisions). SO2 emissions from the backfeed generators are based on the EPA's AP-42, Table 3.4-1.

3. Monitoring Plan- The source shall be required to monitor compliance with the emission limits by monitoring fuel consumption and using emission factors based on heat input. The source shall be required to record fuel consumption and calculate emissions monthly.

The continuous emission monitoring systems shall be used to monitor compliance with the annual NO_X and CO emission limitations. The NSPS Db NO_X limits for the duct burners shall be monitored using the continuous emission monitor. The monitoring methods required by 40 CFR Part 75, Appendix D shall be used to monitor compliance with the SO_2 emission limitations. Compliance with the VOC RACT requirements is presumed when the CO RACT requirements are met.

The heat content of the natural gas shall be determined monthly through either sampling and analysis or use of vendor analyses. In the absence of credible evidence to the contrary, compliance with the opacity, particulate matter and Reg 1 SO_2 limits shall be presumed provided natural gas is used as fuel, except for the diesel generators. The diesel generators are only used during turbine startup. Turbine startup lasts about ten minutes, therefore a Method 9 reading (six minutes) is not practical. In the absence of credible evidence to the contrary, compliance with the opacity limit is assumed during startup when manufacturer's recommendations and good engineering practices are used. If the generators

operate beyond turbine startup, visible emission observations are required.

The source shall be required to monitor the circulation rate of the water in the cooling tower and calculate emissions on a monthly basis. In addition, particulate matter emissions are based on the total solids concentration in the cooling tower, therefore, the source will be required to sample and analyze circulating water to determine the total solids concentration of the circulating water. In lieu of sampling the circulating water to determine the total solids concentration, the source will measure the specific conductivity of the circulating water and multiply that number by 0.67. In the absence of credible evidence to the contrary, compliance with the opacity requirement will be presumed provided the cooling tower and associated drift eliminators are operated and maintained in accordance with the manufacturer's recommendations and good engineering practices.

4. Compliance Status- The permittee indicated in their application that they are in compliance with all applicable requirements.

IV. Compliance Assurance Monitoring (CAM) Requirements

The turbines are equipped with water injection to control NO_X emissions during simple cylce mode and Selective Catalytic Reduction to control NOx emissions during combined cycle mode. Catalytic oxidation reduces CO emissions during combined cycle mode. The simple cycle operation uses combustion control to minimize CO emissions. Since the turbines are not large pollutant specific emission units (i.e. potential controlled emissions, including limits in the Construction Permit, are less than 100 tons/year NOx and CO), the applicant is not required to submit a CAM plan until the permit is renewed (if applicable). Since the operating permit will require the use of CEMs, it is expected that CAM will not apply at time of permit renewal. Therefore, in accordance with 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV, the CEM turbines are not subject to the compliance assurance monitoring (CAM) requirements.

V. Alternative Operating Scenarios

The permittee requests an Alternative Operating Scenario (AOS) to replace permitted turbines with temporary turbines. The permit includes the Division's AOS for temporary turbine replacement.

VI. Acid Rain Provisions:

Both turbines and duct burners are affected units under the Acid Rain Program which is governed by 40 CFR Parts 72, 73, 75, 76, 77 and 78 and as such the source is required to have provisions for the Acid Rain requirements in its Title V permit. Units subject to the Acid Rain requirements are required to hold adequate SO_2 allowances and have NO_X limitations. This facility is not listed under 40 CFR 73.10(b)(2) and therefore must obtain SO_2 allowances as needed. Since these units are not coal-fired boilers, they do not have any NO_X limitations under the Acid Rain Program.

Typically, units subject to the Acid Rain requirements are required to continuously measure and record emissions of SO_2, NO_X (with diluent monitor either CO_2 or O_2) and CO_2 as well as opacity and volumetric flow in accordance with the requirements in 40 CFR Part 75. Since these units burn natural gas, these units are not required to have a continuous opacity monitor and can use an alternate monitoring method (Appendix D), in lieu of installing and operating a continuous emission monitor for SO_2.