COLORADO DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT
AIR POLLUTION CONTROL DIVISION
TELEPHONE: (303) 692-3150

CONSTRUCTION PERMIT

PERMIT NO: **02JE0595**

Issuance 2

DATE ISSUED: November 22, 2016

ISSUED TO: **Colorado Energy Nations Company, LLC**

THE SOURCE TO WHICH THIS PERMIT APPLIES IS DESCRIBED AND LOCATED AS FOLLOWS:

Steam and Power Generation Facility, located at 1003 Vasquez Street, Golden, Jefferson County, Colorado.

THE SPECIFIC EQUIPMENT OR ACTIVITY SUBJECT TO THIS PERMIT INCLUDES THE FOLLOWING:

Facility Equipment ID	AIRS Point	Description	Pollution Control Device
B004	**004**	Combustion Engineering Model CE-VU40, SN 21321, tangential fired, firing coal, natural gas, #2 fuel oil, ethanol, on-site generated on-spec used oil and sludge from the Industrial Wastewater Treatment Plant. Size: 504 MMBtu/hr (Natural Gas) 360 MMBtu/hr (Coal) 427 MMBtu/hr (Fuel Oil)	Wheelabrator-Frye Model 264, Series 8R5 fabric filter baghouse with 8 compartments
B005	**006**	Combustion Engineering Model CE-VU40, SN 27576, tangential fired, firing coal, natural gas, #2 fuel oil, ethanol, on-site generated on-spec used oil and sludge from the Industrial Wastewater Treatment Plant. Size: 650 MMBtu/hr	Carter Day 376RF10, fabric filter baghouse with 12 modules

THIS PERMIT IS GRANTED SUBJECT TO ALL RULES AND REGULATIONS OF THE COLORADO AIR QUALITY CONTROL COMMISSION AND THE COLORADO AIR POLLUTION PREVENTION AND CONTROL ACT C.R.S. (25-7-101 et seq), TO THOSE GENERAL TERMS AND CONDITIONS INCLUDED IN THIS DOCUMENT AND THE FOLLOWING SPECIFIC TERMS AND CONDITIONS:

REQUIREMENTS TO SELF-CERTIFY FOR FINAL APPROVAL

1. Within one hundred and eighty days (180) after issuance of the permit, compliance with the conditions contained on this permit shall be demonstrated to the Division. It is the permittee's responsibility to self certify compliance with the conditions. Failure to demonstrate compliance

within 180 days may result in revocation of the permit. (Information on how to certify compliance was mailed with the permit.)

EMISSION LIMITATIONS AND RECORDS

2. Emissions of air pollutants shall not exceed the following limitations (as calculated using the emission factors included in the Notes to Permit Holder section of this permit). Monthly records of the actual emission rates shall be maintained by the applicant and made available to the Division for inspection upon request. (Reference: Regulation No. 3, Part B, Section II.A.4)

Annual Limits:

Facility Equipment ID	AIRS Point	Tons per Year							Emission Type
		PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	VOC	CO	
B004	**004**	158.0	158.0	NA	1104.0	1892.0	19.21	88.3	Point
B005	**006**	285.0	285.0	184.5	1993.0	3416.0	24.3	103.1	Point

See "Notes to Permit Holder #6" for information on emission factors and methods used to calculate limits.

Compliance with the NO_x and SO_2 emission limits shall be monitored using the CEMS as required by Condition 20 of this permit.

Compliance with the PM, PM_{10}, $PM_{2.5}$, VOC and CO annual limits shall be determined by recording the facility's annual emissions for the pollutants listed above on a rolling twelve (12) month total. By the end of each month a new twelve-month total shall be calculated based on the previous twelve months' data. The permit holder shall calculate monthly emissions and keep a compliance record on site, or at a local field office with site responsibility, for Division review.

3. Facility-wide emissions of air pollutants from all emission units at Colorado Energy Nations Company, LLC- Golden Facility shall not exceed the following limitations. Monthly records of the actual emissions shall be maintained by the applicant and made available to the Division for inspection upon request. (Reference: Colorado Regulation No. 3, Part B, Section II.A.4).

Annual Limits:

Emissions per Averaging Year (Rolling 12 Month Total) (ton per year)						
TSP	PM_{10}	$PM_{2.5}$	SO_2	NO_x	**VOC**	**CO**
--	--	--	1,785.0	--	--	--

Note: See "Notes to Permit Holder #6" for information on emission factors and methods used to calculate limits.

Compliance with the SO_2 emission limits shall be monitored using the CEMS as required by Condition 20 of this permit and the applicable conditions as required by the Operating Permit for this source (96OPJE143).

Compliance with the annual emission limit of SO_2 from Colorado Energy Nations Company, LLC shall be determined by recording the facility's annual emissions for SO_2 on a rolling twelve (12) month total that will begin on January 1, 2017. By the end of each month a new twelve-month total shall be calculated based on the previous twelve month's data. The permit holder shall calculate actual emissions each month and keep a compliance record on site or at a local field office with site responsibility for Division review.

4. Reductions in the allowable sulfur dioxides and nitrogen oxides emissions are required by the Colorado State Implementation Plan for Particulate Matter (PM_{10}), referred to as the PM_{10} SIP, and the February 1994 Settlement Agreement between Coors Brewing Company and the Air Pollution Control Division. The reductions required may be taken from the permit limits for Boiler #4, Boiler #5 or as a combination of reductions from Boilers 4 and 5. The emission reductions required are as follows:

SO_2 and NO_x Required Reductions and Combined Limits for Boilers 4 and 5:

Pollutant	PM_{10} SIP Reductions (tpy)	Reductions from Settlement Agreement (tpy)	Total Reductions (tpy)	Combined Limits for Boilers 4 & 5 (tpy)
SO_2	135	285	420	4888.0
NO_x	225	285	510	2587.0

Compliance with the NO_x and SO_2 emission limits shall be monitored using the CEMS as required by Condition 20 of this permit.

5. The emission points in the table below shall be operated with the control equipment as listed. The owner or operator shall comply with the operation and maintenance requirements as specified in the Operating Permit for the source (96OPJE143)

Facility Equipment ID	AIRS Point	Control Device	Pollutants Controlled
B004	**004**	When firing coal: Wheelabrator-Frye Model 264, Series 8R5 fabric filter baghouse	PM
			PM_{10}
B005	**006**	When firing coal: Carter Day 376RF10, fabric filter baghouse	PM
			PM_{10}
			$PM_{2.5}$

PROCESS LIMITATIONS AND RECORDS

6. This source shall be limited to the following maximum consumption, processing and/or operational rates as listed below. Monthly records of the actual process rate shall be maintained by the applicant and made available to the Division for inspection upon request. (Reference: Regulation 3, Part B, II.A.4)

Process/Consumption Limits

Facility Equipment ID	AIRS Point	Process Parameter	Annual Limit
Limits for Each Boiler:			
B004	**004**	Consumption of Coal as Fuel	150,171 tons

		Consumption of Natural Gas as Fuel	4415 MMscf
		Consumption of #2 Fuel Oil as Fuel	27.1 MMgal
B005	**006**	Consumption of Coal as Fuel	316,333 tons
		Consumption of Natural Gas as Fuel	6,044 MMscf
		Consumption of #2 Fuel Oil as Fuel	41.26 MMgal
Limits for Boilers B004 and B005 Combined:			
B004/B005	**004/ 006**	Consumption of Ethanol as Fuel	34 tons
		Consumption of Sludge as Fuel	71,200 tons
		Consumption of On-Spec Oil as Fuel	600,000 gal

Compliance with the yearly process limits shall be determined on a rolling twelve (12) month total. By the end of each month a new twelve-month total is calculated based on the previous twelve months' data. The permit holder shall calculate monthly process rates and keep a compliance record on site or at a local field office with site responsibility, for Division review.

7. **B005:** The heat input shall not exceed 650 MMBtu/hr or 5,694,000 MMBtu/year. Heat input shall be monitored and recorded monthly using the monthly consumption for each fuel (as determined by Condition 6), and the most recent heat content of each fuel (as determined by Conditions 26 and 27). Monthly heat inputs for all fuel types shall be summed together and used in a twelve month rolling total to monitor compliance with the annual emission limitation. Each month a new twelve month total shall be calculated using the previous twelve months total.

8. **B004 & B005:** On-Spec oil, ethanol and sludge may be burned as auxiliary fuels with coal. On-Spec oil is to be used oil meeting EPA used oil specifications, generated on-site by the MillerCoors Brewery or Colorado Energy Nations Company, LLLC. No. 2 fuel oil is ASTM Grade 2 Distillate oil as defined by ASTM or other methods approved in writing by the Division. Fuel oil is to be used for backup fuel only. Natural gas shall be used as a primary fuel, and/or as ignitor/pilot fuel.

No off specification used oil shall be burned at this facility. All used oil shall meet the used oil specifications limits:

USED OIL SPECIFICATIONS

Compound	Limit
Arsenic	5 ppm
Cadmium	2 ppm
Chromium	10 ppm
Lead	100 ppm
Total halogens	1000 ppm
PCBs	<2 ppm total

In addition, the flash point shall be greater than or equal to 100 degrees F.

Records of the used oil specifications shall be maintained for each batch of used oil received. These specifications may be obtained from the oil supplier or the permittee may have the batch tested.

STATE AND FEDERAL REGULATORY REQUIREMENTS

9. Sulfur Dioxide (SO_2) emissions shall not exceed the following limitations:

a. When burning **Fuel Oil**: SO_2 emissions **from each unit** shall not exceed 0.80 lb/MMBtu, on a 3 hour rolling average (Colorado Regulation No. 1, Section VI.A.3.b and 40 CFR 60.43(a)(1), as adopted by reference in Colorado Regulation No. 6, Part A).

b. When burning **Coal**: SO_2 emissions **from each unit** shall not exceed 1.2 lb/MMBtu, on a 3 hour rolling average (Colorado Regulation No. 1, Section VI.A.3.a.ii and 40 CFR 60.43(a)(2), adopted by reference in Colorado Regulation No. 6, Part A).

c. When burning **different fossil fuels simultaneously in any combination**: the applicable standard for SO_2 **from each unit** shall be determined by proration using the following formula (40 CFR 60.43(b), adopted by reference in Colorado Regulation No. 6, Part A):

$$PS_{SO2} = \frac{y(0.80)+z(1.2)}{(y+z)}$$

Where: PS_{SO2} = Prorated standard for SO_2 when burning different fuels simultaneously, in lb/MMBtu heat input derived from all fossil fuels or from all fossil fuels and wood residue fired;

y = percentage of total heat input derived from liquid fossil fuel

z = percentage of total heat input derived from solid fossil fuel

d. Compliance with the standards of Conditions 9.a through 9.c above shall be based on the total heat input from all fossil fuels burned, including gaseous fuels (40 CFR 60.43(c), adopted by reference in Colorado Regulation No. 6, Part A):

Compliance with the emission limits shall be monitored using the CEMS as required by Condition 20 of this permit.

10. Nitrogen Oxide (NO_X) emissions shall not exceed the following limitations:

a. When burning **Natural Gas**: NO_x emissions **from each unit** shall not exceed 0.20 lb/MMBtu, on a 3 hour rolling average (40 CFR 60.44(a)(1), as adopted by reference in Colorado Regulation No. 6, Part A).

b. When burning **Fuel Oil**: NO_x emissions **from each unit** shall not exceed 0.30 lb/MMBtu, on a 3 hour rolling average (40 CFR 60.44(a)(2), as adopted by reference in Colorado Regulation No. 6, Part A).

c. When burning **Coal**: NO_x emissions **from each unit** shall not exceed 0.70 lb/MMBtu, on a 3 hour rolling average (40 CFR 60.44(a)(3), as adopted by reference in Colorado Regulation No. 6, Part A).

d. When burning **different fossil fuels simultaneously in any combination**: the applicable standard for NO_x **from each unit** shall be determined by proration using the following formula (40 CFR 60.44(b), adopted by reference in Colorado Regulation No. 6, Part A):

$$PS_{NOx} = \frac{w(0.60) + x(0.20) + y(0.30)+z(0.70)}{(w+x+y+z)}$$

Where: PS_{NOx} = Prorated standard for NO_x when burning different fuels simultaneously, in lb/MMBtu heat input derived from all fossil fuels fired or from all fossil fuels and wood residue fired;

w = percentage of total heat input derived from lignite;

x = percentage of total heat input derived from gaseous fossil fuel;

y = percentage of total heat input derived from liquid fossil fuel;

z = percentage of total heat input derived from solid fossil fuel (except lignite)

Compliance with the emission limits shall be monitored using the CEMS as required by Condition 20 of this permit.

11. Particulate Matter (PM) emissions **from each unit** shall not exceed the following limitations: PM emissions **from each unit** shall not exceed 0.10 lb/MMBtu (40 CFR 60.42(a)(1), as adopted by reference in Colorado Regulation No. 6, Part A).

    Compliance with the PM emission limitation while combusting coal shall be monitored by:

    a. Maintaining and operating the baghouses in accordance with the Operation and Maintenance Requirements specified by the Operating Permit for this source (96OPJE143).

    b. Conducting performance tests as specified by the Operating Permit for this source (96OPJE143), except that the minimum stack testing frequency shall be every five years, regardless of the term of the Operating Permit.

    Compliance with the PM emission limitation while combusting fuel oil or natural gas shall be monitored by:

    c. Maintaining and operating the boilers using good combustion practices as established by the requirements of Condition 28.

12. Except as provided for in Condition 13 below, no owner or operators of a source shall allow or cause the emission into the atmosphere of any air pollutant which is in excess of 20% opacity (Colorado Regulation No. 1, Section II.A.1). This opacity standard applies to **each unit**. Compliance with the opacity requirements shall be monitored using the COMS required by Condition 21.

13. No owner or operator of a source shall allow or cause to be emitted into the atmosphere any air pollutant resulting from the building of a new fire, cleaning of fire boxes, soot blowing, start-up, process modifications or adjustment or occasional cleaning of control equipment which is in excess of 30% opacity for a period or periods aggregating more than six (6) minutes in any sixty (60) consecutive minutes (Colorado Regulation No. 1, Section II.A.4). This opacity standard applies to **each unit**. Compliance with the opacity requirements shall be monitored using the COMS required by Condition 21.

    A record shall be kept of the type, date and time of the commencement and completion of each and every condition subject to Colorado Regulation No. 1, Section II.A.4 that results in an exceedance. The records shall be made available for review upon request by the Division.

14. Opacity of emissions shall not exceed 20% for any six-minute period, except for one six-minute period not to exceed 27% per hour (40 CFR Part 60 Subpart D § 60.42(a)(2), as adopted by reference in Colorado Regulation No. 6, Part A). This opacity standard applies to **each unit**. Compliance with the opacity requirements shall be monitored using the COMS required by Condition 21.

    Note that this opacity standard shall apply at all times except during periods of startup, shutdown and malfunction (40 CFR Part 60 Subpart A § 60.11(c), as adopted by reference in Colorado Regulation No. 6, Part A), however, those instances during startup, shutdown and malfunction when the opacity standard is exceeded shall be identified in the Excess Emission Report required by the Operating Permit for this source (96OPJE143).

Also note that this opacity standard is more stringent than the opacity standard identified in Condition 13 during periods of fire building, cleaning of fire boxes, soot blowing, process modifications, and adjustment and occasional cleaning of control equipment. During these periods this condition supersedes Condition 13.

15. **B004 & B005**: Boilers 4 and 5 shall not burn fuel oil from November 1, to March 1 of each year except under the following circumstances (Colorado Regulation No. 1, Section VIII, A.3 & B):

   a. The supplier or transporter of natural gas imposes a curtailment or an interruption of the service.

   b. For necessary testing of equipment used to operate the boiler on oil, testing of fuel and training of personnel.

   c. When an equipment malfunction at the facility makes it impossible or unsafe for the boiler to operate on natural gas.

16. **B004 & B005:** When burning fuel oil under Condition 15, records shall be maintained of the information listed below (Colorado Regulation No. 1, Section VIII.C). These records shall be maintained for a period of five (5) years. In addition, a report containing the following information shall be submitted to the Division for the previous calendar year by April 1 of each new calendar year (Colorado Regulation No. 1, Section VIII.D).

   a. Dates and number of hours fuel oil is burned

   b. Percent sulfur analysis of the fuel oil that is burned.

   c. Number of gallons burned each day.

   d. Reason(s) for the use of the fuel oil.

17. **B004 & B005:** These units are subject to the following Regional Haze Requirements:

   a. Emission Limitations (Colorado Regulation No. 3, Part F, Section VI.A.2):

      i. PM emissions from **each unit** shall not exceed 0.07 lb/MMBtu.

      ii. SO_2 emissions from **each unit** shall not exceed 1.0 lb/MMBtu on a 30-day rolling average basis

      iii. NO_x emissions shall not exceed:

         - 0.37 lb/MMBtu on a 30-day rolling average basis for B004, **or**

         - 0.26 lb/MMBtu on a 30-day rolling average basis as a combined average for B004 and B005

      iv. NO_x emissions shall not exceed:

         - 0.19 lb/MMBtu on a 30-day rolling average basis for B005, **or**

         - 0.26 lb/MMBtu on a 30-day rolling average basis as a combined average for B004 and B005

   b. Compliance Date

i. The permittee must comply with the above limits and averaging times as expeditiously as practicable, but in no event later than five years after EPA approval of Colorado's state implementation plan for regional haze, or relevant component thereof. The permittee must maintain control equipment or operational practices required to comply with the above limits and averaging times, and establish procedures to ensure that such equipment or operational practices are properly operated and maintained. (Colorado Regulation No. 3, Part F, Section IV.A.3)

c. PM Monitoring

i. Within 60 days of the compliance deadline specified in Condition 17.b.i of this permit, the owner/operator shall conduct a stack test to measure particulate emissions in accordance with the requirements and procedures set forth in EPA Test Method 5, 5B, 5D or 17, as appropriate, as set forth in 40 CFR Part 60, Appendix A. Stack testing for particulate matter shall be performed annually, except that: (1) if any test results indicate emissions are less than or equal to 50% of the emission limit, another test is required within five years; (2) if any test results indicate emissions are more than 50%, but less than or equal to 75% of the emission limit, another test is required within three years; and (3) if any test results indicate emissions are greater than 75% of the emission limit, an annual test is required until the provisions of (1) or (2) are met. Each test shall consist of three test runs, with each run at least 60 minutes in duration (Colorado Regulation No. 3, Part F, Section VII.C.3)

d. SO_2 and NOx Monitoring

i. At all times after the compliance deadline specified in Condition 17.b.i of this permit, the owner/operator of each BART or RP unit shall maintain, calibrate and operate a CEMS in full compliance with the requirements in 40 CFR Part 60 Section 60.13 and Part 60 Appendices A, B and F to accurately measure SO_2, NO_x and diluent, if diluent is required. The CEMS shall be used to determine compliance with the SO_2 and NO_x Regional Haze emission limits for each such unit. Such limits are expressed in units of pounds per million Btu. The owner/operator shall calculate emissions in the applicable units. In determining compliance with the SO_2 and NO_X Regional Haze limits, all periods of emissions shall be included, including startups, shutdowns, emergencies and malfunctions (Colorado Regulation No. 3, Part F, Section VII.B.1.b).

Compliance with the emission limits of this Condition 17 shall be monitored using the methods specified in Condition 20 of this permit.

ii. "Operating day" means any twenty-four-hour period between midnight and the following midnight during which any fuel is combusted at any time in a BART unit, BART alternative program unit, or Reasonable Progress unit Colorado Regulation No. 3, Part F, Section VII.A.4)

iii. Except as provided for in Condition 17.d.iv below, for any hour in which fuel is combusted in the BART or RP unit, the owner/operator shall calculate hourly NO_x and SO_2 emissions in the appropriate units (lbs/MMbtu) in accordance with the provisions in 40 CFR Part 60. These hourly values shall be used to determine compliance in accordance with the particular limits averaging time, as follows (Colorado Regulation No. 3, Part F, Section VII.B.1.b.(i))

- Pounds per Million Btu Regional Haze Limits on a 30-day rolling average: Before the end of each operating day, the owner/operator shall calculate and record the 30-day rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 3, Part F, Section VII.B.1.b.(i).(1)).

iv. For any hour in which fuel is combusted in CENC Unit 4 or Unit 5, the owner/operator shall calculate hourly NO_x emissions in the appropriate units (lbs/MMbtu) in accordance with the provisions in 40 CFR Part 60. These hourly values shall be used to determine compliance with the Regional Haze limits, as follows (Colorado Regulation No. 3, Part F, Section VII.B.1.b.(iii):

- Individual unit pound per Million Btu on a 30-day rolling average Regional Haze Limit: Before the end of each operating day, the owner/operator shall calculate and record the 30-day rolling average emission rate in lb/MMBtu from all valid hourly emission values from the CEMS for the previous 30 operating days (Colorado Regulation No. 3, Part F, Section VII.B.1.b.(iii).(1)), OR

- Combined units 4 and 5 lbs/MMbtu 30-day rolling average Regional Haze Limit: Before the end of each operating day, the owner/operator shall calculate and record a 30-day rolling average using data from the previous 30 operating days in accordance with the following equation (Colorado Regulation No. 3, Part F, Section VII.B.1.b.(iii).(2)):

$$\text{Average ER}=\frac{[(\text{ER}_4)(\text{HI}_4)+(\text{ER}_5)(\text{HI}_5)]}{(\text{HI}_4)+(\text{HI}_5)}$$

Where:

ER_4 = average NO_X emission rate, in pounds per MMbtu over the 30 day period. This is an average of all valid hours within the 30 operating day period for Unit 4.

ER_5 = average NO_X emission rate, in pounds per MMbtu over the 30 day period. This is an average of all valid hours within the 30 operating day period for Unit 5.

HI_4 = Total heat input over the 30 operating day period for Unit 4.

HI_5 = Total heat input over the 30 operating day period for Unit 5.

For purposes of determining HI and ER values for each individual boiler in the equation for average ER above, *operating day period* for each unit shall mean the previous 30 days that meet the definition of “operating day” in Condition 17.d.ii above. Any day (between midnight and the following midnight) in which a boiler did not combust fuel shall not be included when defining the operating day period.

HI values for each unit in the equation above are the sum of the hourly heat input values for the 30 day operating period as recorded on the Data Acquisition and Handling System (DAHS) in accordance with the requirements of Appendix G of Operating Permit 96OPJE143.

- The owner or operator shall indicate in the excess emission reports required by Section VII.E of this Part F, which compliance demonstration method has been followed for the reporting period. equation (Colorado Regulation No. 3, Part F, Section VII.B.1.b.(iii).(3))

e. Recordkeeping and Reporting Requirements

i. The owner/operating shall maintain the following records for at least five years (Colorado Regulation No. 3, Part F, Section VII.D):

- All CEMS data as required in the applicable regulation, stack test data, and data collected pursuant to the CAM plan, including the date, place, and time of sampling, measurement, or testing; parameters sampled, measured, or tested and results; the company, entity, or person that performed the testing, if applicable; and any field data sheets from testing. (Colorado Regulation No. 3, Part F, Section VII.D.1)

  The CAM Plan data requirement specified above does not apply until after the CAM Plan has been established in a renewal of Operating Permit 96OPJE043.

- Records of quality assurance and quality control activities for emissions measuring systems including, but not limited to, any records required by 40 CFR Part 60, 63, or 75. (Colorado Regulation No. 3, Part F, Section VII.D.2)

ii. The owner/operator of a BART, RP or BART alternative program unit shall submit semi-annual excess emissions reports no later than the 30th day following the end of each semi-annual period unless more frequent reporting is required. Excess emissions means emissions that exceed the Regional Haze emissions limits. Excess emission reports shall include the information specified in 40 CFR Part 60, Section 60.7(c) (Colorado Regulation No. 3, Part F, Section VII.E)

iii. The owner/operator of a BART, RP or BART alternative program unit shall submit reports of any required performance stack tests for particulate matter, to the Division within 60 calendar days after completion of the test. (Colorado Regulation No. 3, Part F, Section VII.E)

18. This source is subject to the National Emissions Standards for Hazardous Air Pollutants requirements of Regulation No. 8, Part E, Subpart DDDDD (40 CFR Part 63, Subpart DDDDD), for Industrial, Commercial, and Institutional Boilers and Process Heaters including, but not limited to, the following:

The requirements below reflect the rule language of 40 CFR Part 63, Subpart DDDDD published in the Federal Register on November 20, 2015. However, if revisions to this subpart are published at a later date, the owner or operator is subject to the requirements contained in the revised version of 40 CFR Part 63, Subpart DDDDD.

Emission Limitations and Work Practice Standards

a. This source is subject to the applicable emission limitations and work practice standard requirements as specified in §63.7500.

General Compliance Requirements

b. This source is subject to the applicable general compliance requirements as specified in §63.7505.

Testing and Initial Compliance Requirements

c. This source is subject to the applicable testing and initial compliance requirements as specified in §63.7510, §63.7515, §63.7520, §63.7521, §63.7522, §63.7525, and §63.7530,

Continuous Compliance Requirements

d. This source is subject to the applicable continuous compliance requirements as specified in §63.7535, §63.7540, and §63.7541

Notification, Reports, and Records

e. This source is subject to the applicable notification, reports, and records requirements as specified in §63.7545, §63.7550, §63.7555, and §63.7560

19. This source is subject to the requirements in 40 CFR Part 63, Subpart A "General Provisions", as adopted by reference in Colorado Regulation No. 8, Part E, Subpart A. These requirements include, but are not limited to the following:

    a. §63.4 – Prohibited Activities and Circumvention
    b. §63.5 – Preconstruction Review and Notification Requirements
    c. §63.8 – Monitoring Requirements

CONTINUOUS EMISSION MONITORING SYSTEM & CONTINOUS OPACITY MONITORING SYSTEM REQUIREMENTS

20. **B004 & B005**: For each unit, the owner or operator shall install, certify, maintain and operate CEMS equipment for measuring SO_2, NO_X and gas flow rate. The CEMS shall meet the requirements specified by the Operating Permit for this source (96OPJE143).

21. **B004 & B005:** Continuous Opacity Monitoring Systems. For each unit, the owner or operator shall install, certify, maintain and operate a continuous in-stack monitoring device for the measurement of opacity. The COMS shall meet the requirements specified by the Operating Permit for this source (96OPJE143). In the event that the COMS is unable to provide quality assured data, Method 9 opacity observations may be performed as specified by the Operating Permit for this source (96OPJE143).

OPERATING & MAINTENANCE REQUIREMENTS

22. For each unit, the owner or operator shall comply with the Operation and Maintenance Requirements specified by the Operating Permit for this source (96OPJE143)

COMPLIANCE TESTING AND SAMPLING

Initial Testing Requirements

23. An initial compliance test for PM2.5 on Boiler B005 was successfully performed. No further initial testing is required.

Periodic Testing Requirements

24. Subsequent compliance testing for $PM_{2.5}$ shall be required for **Boiler B005** based on the following schedule:

Last Test Result	**Schedule**
Less than 50% of emission limit	Test again within 5 years
50% to less than 75% of emission limit	Test again within 3 years
75% or more of emission limits	Test again within 1 year

25. For each unit, the owner or operator shall conduct particulate matter performance tests as specified by the Operating Permit for this source (96OPJE143), except that the minimum stack testing frequency shall be every five years, regardless of the term of the Operating Permit

26. **B004 & B005:** Fuel oil and coal sulfur and heat content shall be determined as specified by the Operating Permit for this source (96OPJE143). Btu content shall be based on the higher heating value of the fuel.

27. **B004 & B005:** The Btu content of natural gas used to fuel this equipment shall be determined monthly using the appropriate ASTM Methods or equivalent, if approved by the Division in advance. Btu content shall be based on the higher heating value of the fuel.

ADDITIONAL REQUIREMENTS

28. At all times, including periods of startup, shutdown, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. (40 CFR Subpart A §60.11(d), as adopted by reference in Colorado Regulation No. 6, Part A)

29. The permit number and AIRS ID number shall be marked on the subject equipment for ease of identification. (Reference: Regulation No. 3, Part B, III.E.) (State only enforceable)

30. A revised Air Pollutant Emission Notice (APEN) shall be filed: (Reference: Regulation No. 3, Part A, II.C)

    a. Annually whenever a significant increase in emissions occurs as follows:

    For any criteria pollutant:

    For sources emitting **less than 100 tons per year of a criteria pollutant**, a change in annual actual emissions of five (5) tons per year or more, above the level reported on the last APEN; or

    For volatile organic compounds (VOC) and nitrogen oxides sources (NO_x) in ozone nonattainment areas emitting **less than one hundred tons of VOC or NO_x per year**, a change in annual actual emissions of one (1) ton per year or more or five percent, whichever is greater, above the level reported on the last APEN; or

    For sources emitting **100 tons per year or more of a criteria pollutant**, a change in annual actual emissions of five percent or fifty (50) tons per year or more, whichever is less, above the level reported on the last APEN submitted; or

    For sources emitting **any amount of lead**, a change in actual emissions of fifty (50) pounds of lead above the level reported on the last APEN submitted.

    For any non-criteria reportable pollutant:

    If the emissions increase by 50% or five (5) tons per year, whichever is less, above the level reported on the last APEN submitted to the Division.

    b. Whenever there is a change in the owner or operator of any facility, process, or activity; or

c. Whenever new control equipment is installed, or whenever a different type of control equipment replaces an existing type of control equipment; or

d. Whenever a permit limitation must be modified; or

e. No later than 30 days before the existing APEN expires.

31. All equipment currently covered by an existing Title V permit must comply with all monitoring, reporting, and record keeping requirements outlined in the current Title V Operating Permit.

32. This source is subject to the provisions of Regulation No. 3, Part C, Operating Permits (Title V of the 1990 Federal Clean Air Act Amendments). The provisions of this construction permit must be incorporated into the operating permit. The application for the modification to the Operating Permit is due within one year of issuance of this permit.

33. This permit replaces the following permits which are cancelled upon issuance of this permit: 10JE660 and 10JE305-1.

GENERAL TERMS AND CONDITIONS:

34. This permit and any attachments must be retained and made available for inspection upon request. The permit may be reissued to a new owner by the Division as provided in Regulation No. 3, Part B, Section II.B upon a request for transfer of ownership and the submittal of a revised APEN and the required fee.

35. If this permit specifically states that final approval has been granted, then the remainder of this condition is not applicable. Otherwise, the issuance of this construction permit does not provide "final" authority for this activity or operation of this source. Final approval of the permit must be secured from the Division in writing in accordance with the provisions of 25-7-114.5(12)(a) C.R.S. and Regulation No. 3, Part B, Section III.G. Final approval cannot be granted until the operation or activity commences and has been verified by the Division as conforming in all respects with the conditions of the permit. Once self-certification of all points has been reviewed and approved by the Division, it will provide written documentation of such final approval. **Details for obtaining final approval to operate are located in the Requirements to Self-Certify for Final Approval section of this permit.**

36. This permit is issued in reliance upon the accuracy and completeness of information supplied by the applicant and is conditioned upon conduct of the activity, or construction, installation and operation of the source, in accordance with this information and with representations made by the applicant or applicant's agents. It is valid only for the equipment and operations or activity specifically identified on the permit

37. Unless specifically stated otherwise, the general and specific conditions contained in this permit have been determined by the Division to be necessary to assure compliance with the provisions of Section 25-7-114.5(7)(a), C.R.S.

38. Each and every condition of this permit is a material part hereof and is not severable. Any challenge to or appeal of a condition hereof shall constitute a rejection of the entire permit and upon such occurrence, this permit shall be deemed denied *ab initio*. This permit may be revoked at any time prior to self-certification and final authorization by the Division on grounds set forth in the Colorado Air Pollution Prevention and Control Act and regulations of the AQCC including failure to meet any express term or condition of the permit. If the Division denies a permit, conditions imposed upon a permit are contested by the applicant, or the Division revokes a

permit, the applicant or owner or operator of a source may request a hearing before the AQCC for review of the Division's action.

39. Section 25-7-114.7(2)(a), C.R.S. requires that all sources required to file an Air Pollution Emission Notice (APEN) must pay an annual fee to cover the costs of inspections and administration. If a source or activity is to be discontinued, the owner must notify the Division in writing requesting a cancellation of the permit. Upon notification, annual fee billing will terminate.

40. Violation of the terms of a permit or of the provisions of the Colorado Air Pollution Prevention and Control Act or the regulations of the AQCC may result in administrative, civil or criminal enforcement actions under Sections 25-7-115 (enforcement), -121 (injunctions), -122 (civil penalties), -122.1 (criminal penalties), C.R.S**.**

By: Rachel Frisz
Rachel Frisz
Permit Engineer

By: Matthew Burgett
Matthew Burgett, P.E.
Title V Operating Permit Unit Supervisor

Permit History

Issuance	**Date**	**Description**
Initial Approval	6/20/2013	Issued to Colorado Energy Nations Company, LLC Permit 02JE0595 was first created in the late 1990's and was intended to supersede the two individual construction permits for Boilers B004 & B005 (10JE660 and 11JE305-1, respectively) and establish the combined reductions across both boilers required by the PM_{10} SIP and Settlement Agreement. The requirements were instead established directly in the initial issuance of Operating Permit 96OPJE143 and 02JE0595 was never issued. This permit supersedes Colorado Construction Permit No. 07JE0114B, which was the original Regional Haze BART Construction Permit. Note that the previous BART program was never approved as part of the Regional Haze SIP, and therefore the requirements of 07JE0114B were never applicable. This issuance of 02JE0595 is increasing the allowable limit for natural gas in Boiler 005 so that the facility can meet new regional haze limits. The natural gas limit is increasing from 350 MMscf/year to 6,044 MMscf/year for Boiler 005. The VOC limit for B005 is increasing from 9.5 tpy to 24.3 tpy.
Issuance 2	This Issuance	Modified to include facility-wide SO2 limitation and incorporation of 40 CFR Part 63 Subpart DDDDD

Notes to permit holder:

1) The permit holder is required to pay fees for the processing time for this permit. An invoice for these fees will be issued after the permit is issued. The permit holder shall pay the invoice within 30 days of receipt of the invoice. Failure to pay the invoice will result in revocation of this permit (Reference: Regulation No. 3, Part A, Section VI.B.)

2) The production or raw material processing limits and emission limits contained in this permit are based on the production/processing rates requested in the permit application. These limits may be revised upon request of the permittee providing there is no exceedence of any specific emission control regulation or any ambient air quality standard. A revised air pollution emission notice (APEN) and application form must be submitted with a request for a permit revision.

3) This source is subject to the Common Provisions Regulation Part II, Subpart E, Affirmative Defense Provision for Excess Emissions During Malfunctions. The permittee shall notify the Division of any malfunction condition which causes a violation of any emission limit or limits stated in this permit as soon as possible, but no later than noon of the next working day, followed by written notice to the Division addressing all of the criteria set forth in Part II.E.1. of the Common Provisions Regulation. See: http://www.colorado.gov/cs/Satellite/CDPHE-Main/CBON/1251601911433.

4) In accordance with C.R.S. 25-7-114.1, each Air Pollutant Emission Notice (APEN) associated with this permit is valid for a term of five years from the date it was received by the Division. A revised APEN shall be submitted no later than 30 days before the five-year term expires. Please refer to the most recent annual fee invoice to determine the APEN expiration date for each emissions point associated with this permit. For any questions regarding a specific expiration date call the Division at (303)-692-3150.

5) The following emissions of non-criteria reportable air pollutants are estimated based upon the process limits as indicated in this permit. This information is listed to inform the operator of the Division's analysis of the specific compounds emitted if the source(s) operate at the permitted limitations.

Emissions less than reportable thresholds are not included in the following table.

AIRS Point	Pollutant	CAS #	Uncontrolled Emission Rate (lb/yr)	Controlled Emission Rate (lb/yr)
004	Acetaldehyde	75070	86	86
	Benzene	71432	195	195
	Benzyl Chloride	100447	105	105
	Cyanide	20097	375	375
	Formaldehyde	50000	1653	1653
	Hexane	110543	7947	7947
	Isophorone	78591	87	87
	Methyl Chloride	74873	80	80
	Hydrochloric Acid	7647010	90.1 tons	90.1 tons
	Hydrogen Fluoride	7664393	11.3 tons	11.3 tons
	Antimony	0	108	3
	Arsenic	0	246	6
	Beryllium	0	126	3
	Cadmium	0	306	8
	Chromium	0	1562	39
	Cobalt	0	601	15
	Lead	0	2523	63
	Manganese	0	2943	74
	Mercury	0	499	13
	Nickel	0	1682	42
	Selenium	0	7809	195
	POM	0	89	89

Emissions shown above are based on the highest emitting fuel for each pollutant. Coal is the highest emitting fuel for all pollutants except formaldehyde (fuel oil) and hexane (natural gas). Emissions are based on AP42: 1.1-14, 1.1-15 and 1.1-18 for coal (9/98), 1.3-8 for fuel oil (5/10) and 1.4-3 for natural gas (7/98).

Emissions less than reportable thresholds are not included in the following table.

AIRS Point	Pollutant	CAS #	Uncontrolled Emission Rate (lb/yr)	Controlled Emission Rate (lb/yr)
	Acetaldehyde	75070	180	180
	Acrolein	107028	92	92
	Benzene	71432	411	411
	Benzyl Chloride	100447	221	221
	Cyanide	20097	791	791
	Formaldehyde	50000	2517	2517
	Hexane	110543	10,879	10,879
	Isophorone	78591	184	184
	Methyl Chloride	74873	168	168
	Methyl Hydrazine	60344	54	54
	Methylene Chloride	75092	92	92
	Hydrochloric Acid	7647010	189.8 tons	189.8 tons
006	Hydrogen Fluoride	7664393	23.7 tons	23.7 tons
	Antimony	0	228	6
	Arsenic	0	519	13
	Beryllium	0	266	7
	Cadmium	0	645	16
	Chromium	0	3290	82
	Cobalt	0	1265	32
	Lead	0	5314	133
	Manganese	0	6200	155
	Mercury	0	1050	26
	Nickel	0	3543	89
	Selenium	0	16,450	411
	POM	0	136	136

Emissions shown above are based on the highest emitting fuel for each pollutant. Coal is the highest emitting fuel for all pollutants except formaldehyde (fuel oil) and hexane (natural gas). Emissions are based on AP42: 1.1-14, 1.1-15 and 1.1-18 for coal (9/98), 1.3-8 for fuel oil (5/10) and 1.4-3 for natural gas (7/98).

6) **B004 & B005**: Emissions calculations, for monitoring compliance with the annual limits of this permit, shall be calculated using the following emission factors and the amount of fuel used for each specified fuel type:

Pollutant	#2 Fuel Oil ($lb/10^3$ gal)	Natural Gas (lb/MMscf)	Ethanol ($lb/10^3$ gal)	Waste Oil ($lb/10^3$ gal)
PM	2	7.6	0.6	64 * %Ash
PM10	50%*PM	7.6	0.6	51* %Ash
PM2.5	4.3*%Ash + 1.3	7.6	0.6	51* %Ash
CO	5	24	3.6	5
VOC	0.2	8.7	0.4[1]	1.0

Note 1: TOC – CH_4 = 0.6 – 0.2 = 0.4

Pollutant	Sub-bituminous Coal (lb/ton)	Bituminous Coal (lb/ton)	Lignite (lb/ton)	Anthracite Coal (lb/ton)
PM[2]	10 * %Ash	10 * %Ash		10 * %Ash
PM10[2]	2.3 * %Ash	2.3 * %Ash	2.3 * %Ash	2.3 * %Ash
PM2.5[2]	0.01* %Ash + (0.1*%S-0.03)*HHV[1]			
CO	0.5	0.5	0.25	
VOC (NMTOC)	0.06	0.06	0.04	

Note 1: HHV is the higher heating value of coal, on a MMBtu/ton basis.
Note 2: Calculations for PM and PM10 may assume a control efficiency of 99.9% when the requirements for operation and maintenance of the baghouse are met. Calculations for the filterable portion of PM2.5 may use the controlled emission factor shown above when the requirements for operation and maintenance of the baghouse are met. The filterable portion of PM2.5 is represented by the first half of the equation shown above: (0.01 * %Ash).

7) The emission levels contained in this permit are based on the following emission factors:

B004:

Pollutant	Emission Factor	Source
PM	0.10 lb/MMBtu	40 CFR 60.42(a)(1)
PM10	0.10 lb/MMbtu	40 CFR 60.42(a)(1)
NO_x	0.70 lb/MMBtu	40 CFR 60.44(a)(3)
CO	40 lb/MMscf	Construction Permit 10JE660
VOC	8.7 lb/MMscf	AP42 1.4-2 (TOC factor minus methane factor)
SO2	1.2 lb/MMBtu	40 CFR 60.43(a)(2)

PM, PM_{10} and SO_2 Limits based on design rate of 360 MMBtu/hr when burning coal and 8760 hrs/yr. CO and VOC limits based on assumed heat value of 1000 btu/scf and design rate of 504 MMBtu/hr when burning natural gas and 8760 hrs/yr. Permit 10JE660 established CO limits based on 40 lb/MMscf, however this is not the AP42 factor for tangential-fired boilers.

B005:

Pollutant	Emission Factors Lb/MMBtu	Source
PM	0.10 lb/MMBtu	40 CFR 60.42(a)(1)
PM10	0.10 lb/MMBtu	40 CFR 60.42(a)(1)
PM2.5	1.167 lb/ton coal	AP42 1.1-4 & 1.1-5
NO_x	0.70 lb/MMBtu	40 CFR 60.44(a)(3)
CO	5 lb/10^3 gal	AP42 1.3-1
VOC	8.7 lb/MMscf	AP42 1.4-2 (TOC factor minus methane factor)
SO2	1.2 lb/MMBtu	40 CFR 60.43(a)(2)

PM, PM_{10} and SO_2 Limits based on design rate of 650 MMBtu/hr when burning coal and 8760 hrs/yr. CO limit based on an assumed heat value of 138,000 Btu/gal when burning #2 fuel oil and a design rate of 650 MMBtu/hr and 8760 hr/yr. VOC limit based on assumed heat value of 1000 btu/scf and design rate of 650 MMBtu/hr when burning natural gas and 8760 hrs/yr. $PM_{2.5}$ limits are based on the design rate of 650 MMBtu/hr and 8760 hr/yr, maximum ash and sulfur contents of 7.0% and 0.781%, respectively, a coal heating value of 11,400 Btu/lb, and a control efficiency of 99.9% on the filterable portion only.

8) The source conducted an applicability test under Reg 3, Part D, Section I.B.1 to determine that the modification addressed by this permit (increasing the natural gas throughput limit and VOC emission limit for Boiler 5) does not qualify as a major modification to a major stationary source under the Prevention of Significant Deterioration and/or Non-Attainment New Source Review Rules. The following information is incorporated into this Notes to Permit Holder section in accordance with Regulation No. 3, Part D, Section I.B.4.

Pollutant	BAE (tpy)	Demand Growth (tpy)	PAE (tpy)	Actual to Projected Actual Applicability Test Result (tpy)	Significance Level (tpy)
CO	46.0	NA	54.5	8.5	100
NO_x	970.6		973.3	2.7	40
SO_2	1845.3		1877.1	31.8	40
VOC	5.6		19.8	14.22	40
PM	82.4		101.0	18.6	25
PM_{10}	19.0		23.2	4.3	15
$PM_{2.5}$	41.9		51.8	9.9	10
CO_{2e}	611,826		648,035	36,210	75,000

BAE is Baseline Actual Emissions. PAE is projected actual emissions. Demand Growth is that portion of each existing unit's emissions following the project that the unit could have accommodated during the consecutive twenty-four month period used to establish the baseline actual emissions and that are unrelated to the project, including any increased utilization due to product demand growth. See Attachment A for details of the calculations and supporting documentation that were used to develop the values listed in the table above.

In accordance with the definition of Projected Actual Emissions in Reg 3, Part D, Section II.a.36.a, the projected actual emissions shown above are the maximum annual rate, in tons per year, at which Boiler B005 is projected to emit in any one of the five years (twelve-month period) following the date the unit resumes regular operation after the project.

If Boiler B005 operates with actual emission rates higher than those listed as projected actual emissions in the table above any one of the five years (twelve-month period) following the date the unit resumes regular operation after the project, the project may need to be re-evaluated to determine whether the project resulted in a significant emissions increase or a significant net emissions increase at a major stationary source.

9) This facility is classified as follows:

Applicable Requirement	Status
Operating Permit*	Major Source PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, NO_x, Individual HAPs and Total HAPs, GHGs
PSD*	Major Stationary Source PM, PM_{10}, $PM_{2.5}$, SO_2, VOC, NO_x, Individual HAPs and Total HAPs, GHGs
Nonattainment New Source Review*	Major Stationary Source NO_x, VOC
MACT DDDDD	Major Source

* Applicability is determined based on all co-located sources combined

10) Full text of the Title 40, Protection of Environment Electronic Code of Federal Regulations can be found at the website listed below:

http://ecfr.gpoaccess.gov/

Part 60: Standards of Performance for New Stationary Sources		
NSPS	60.1-End	Subpart A – Subpart KKKK
NSPS	Part 60, Appendixes	Appendix A – Appendix I
Part 63: National Emission Standards for Hazardous Air Pollutants for Source Categories		
MACT	63.1-63.599	Subpart A – Subpart Z
MACT	63.600-63.1199	Subpart AA – Subpart DDD
MACT	63.1200-63.1439	Subpart EEE – Subpart PPP
MACT	63.1440-63.6175	Subpart QQQ – Subpart YYYY
MACT	63.6580-63.8830	Subpart ZZZZ – Subpart MMMMM
MACT	63.8980-End	Subpart NNNNN – Subpart XXXXXX

ATTACHMENT A:

PREVENTION OF SIGNIFICANT DETERIORATION/NON-ATTAINMENT NEW SOURCE REVIEW APPLICABILITY TEST

The following provides the details of the applicability test used to determine PSD/NANSR non-applicability for the modification permitted under the Initial Approval Issuance of this permit.

02JE0595.IA - PSD/NANSR Applicability Test

March/April 2013: Increase NG fuel limit and VOC emission limit on Boiler B005

Reg 3, Part D Section I.B.1 - Applicability Test to Determing PSD/NANSR Applicability

Actual-to-projected-actual applicability test for projects that involve only existing emission units

Step 1: Determine Baseline Actual Emissions (BAE)

Baseline actual emissions for CO, NOx, SO2, VOC, PM and PM10 were chosen by the applicant from APENs submitted for years in the 10 year period as allowed under Part D, II.A.4.b.

Baseline actual emissions for these pollutants are either monitored by the CEMS (NOx/SO2), or calculated based on emission factors and monitored fuel use rates as required by the Title V Permit for this source (96OPJE143).

Baseline actual emissions for PM2.5 and CO2e were calculated using AP42 factors and monitored fuel use rates.

PM2.5 BAE Calculations:

Coal Emission Factors

Filterable Portion (baghouse controlled): 0.01A lb/ton from AP42 Table 1.1-6

Condensable Portion: (0.1S - 0.03) lb/MMBtu from AP42 Table 1.1-5

Natural Gas Emission Factors

Total PM factor from AP42 1.4-2, converted to MMbtu basis using 1020 btu/scf

HHV = 1064 btu/scf (from original TV application)

EF=	0.00745098	lb/MMBtu
EF=	7.927843137	lb/MMscf

Used Oil Emission Factors

EF = 51A lb/Mgal from AP42 Table 1.11-1

Assumes PM2.5 = PM10. Uses the same source category as that established for the PM10 emission factor in the Title V permit for the source (96OPJE143)

PM2.5 emissions from Coal

year	tons coal	%A	%S	Btu/lb	PM25 filt	PM25cond	PM25 total
2004	190558	8.18	0.44	12110	7.8	32.3	40.1
2005	198476	7.9	0.44	12179	7.8	33.8	41.7

PM2.5 emissions from Natural Gas

year	MMscf gas	PM25
2004	1.399	0.006
2005	1.844	0.007

PM2.5 emissions from Used Oil

year	Mgal	%A	PM25
2004	124.998	0.650	2.1
2005	123.003	0.650	2.0

BAE PM2.5 emissions for all fuels: annual average 2004/2005

41.93	tpy

CO2e BAE Calculations:

Coal Emission Factors

CO2	6250	lb/ton	AP42 1.1-20
CH4	0.04	lb/ton	AP42 1.1-19
N2O	0.08	lb/ton	AP42 1.1-19

Natural gas Emission Factors

CO2	117.6	lb/MMBtu	AP42 1.4-2
CH4	0.0023	lb/MMBtu	AP42 1.4-2
N2O	0.0022	lb/MMBtu	AP42 1.4-2

*Converted to lb/MMBtu based on HHV of 1020 btu/scf

Used Oil Emission Factors

CO2	22000	lb/Mgal	AP42 1.11-3

CO2e emissions from Coal

year	tons coal	CO2 tpy	CH4 tpy	N2O tpy	CO2e tpy
2004	190558	595,494	3.8	7.6	597,937
2005	198476	620,238	4.0	7.9	622,782

*Assumes 99.9% control from filterable portion only (baghouse)

**Based on GWPs: 1 for CO2, 21 for CH4 and 310 for N2O

CO2e emissions from Natural Gas

year	MMscf NG	CO2 tpy	CH4 tpy	N2O tpy	CO2e tpy
2004	1.399	87.64	0.0017	0.0016	88
2005	1.844	116	0.0022	0.0021	116

*Based on a heat value of 1065 btu/scf

**Based on GWPs: 1 for CO2, 21 for CH4 and 310 for N2O

CO2e emissions from Used Oil

year	Mgal	CO2 tpy	CO2e tpy
2004	124.998	1375	1375.0
2005	123.003	1353	1353.0

BAE CO2e emissions for all fuels: annual average 2004/2005

611,826	tpy

Baseline Actual Emissions

Pollutant	tpy	Period
CO	45.98	2005-2006 avg
NOx	970.64	2004-2005 avg
SO2	1,845.30	2004-2005 avg
VOC	5.55	2005-2006 avg
PM	82.44	2005-2006 avg
PM10	18.97	2005-2006 avg
PM25	41.93	2004-2005 avg
CO2e	611,826	2004-2005 avg

Step 2: Determine "Demand Growth" Emissions

"Demand growth" is a portion of projected actual emissions that may be excluded under II.A.36.b.(iii):

> Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive twenty-four month period used to establish the baseline actual emissions under Section II.A.4. of this part D and that are also unrelated to the particular project, including any increased utilization due to product demand growth; or,

The applicant is not claiming any demand growth exclusions from Projected Actual Emissions;
this results in a more conservative result for the applicability test.

Step 3: Determine Projected Actual Emissions (PAE)

PAE is determined for three different operating scenarios, because emission profiles will vary depending on the options available for meeting regional haze NOx limits. Note that the regional haze rule allows individual NOx limits for boilers 4 and 5, or an combined limit for boilers 4 and 5. This results in the following possible operating scenarios with respect to balancing coal and natural gas in Boiler 005:

Scenario #1: coal is fired all year in Boiler 5, compliance with regional haze based on combined limit for boiler 4 and 5

Scenario #2: same as scenario #1, except that a turnaround occurs for boiler 4; during this one month period, natural gas is fired in Boiler 5

Scenario #3: boiler 5 burns natural gas for the entire year, either to meet regional haze requirements for the boilers individually, or to meet the combined limit for boilers 4/5 while boiler 4 is burning coal

The max PAE is chosen as the highest value for each pollutant for all three scenarios, since all three scenarios are possible during the projected period and cannot be ruled out at this time.

Scenario #1: No turnaround, firing coal only

Coal Use	206524	tpy
Coal HHV	11221	Btu/lb
Coal %A	9.78	
Coal %S	0.48	
PM Ctrl	0.99	
PM10 ctrl	0.99	

These values represent a projection of the actual heat output for the boiler during a year in which only coal is used as fuel. Sulfur, ash and HHV are the worst case values expected based on actual values monitored between 2004 & 2012

Pollutant	EF*	tpy	EF Source
CO	0.5	51.631	AP42 1.1-3
NOx	0.42	973.3	Note 1
SO2	0.81	1877.1	Note 1
VOC	0.06	6.20	AP42 1.1-19
PM	97.8	101.0	AP42 1.1-4
PM10	22.494	23.2	AP42 1.1-4
PM25 filt	0.0978	10.1	AP42 1.1-6
PM25 cond	0.018	41.7	AP42 1.1-5
PM25 Total		51.8	--
CO2	6250	645,388	AP42 1.1-20
N2O	0.08	8	AP42 1.1-19
CH4	0.04	4	AP42 1.1-19
CO2e		648,035	--

*all EF units are lb/ton, except NOx, SO2 and PM25 condensible, which are lb/MMBtu

Note 1: EF calculated based on CEMS monitoring data - highest annual average 2004 - 2012

Scenario #2: Turnaround (one month of natural gas)

Coal Emissions are assumed to be 91.67% of those calculated for scenario #1 (11 out of 12 months)

MMBtu total	4634812	MMBtu/yr
Gas Use	386234	MMBtu/yr
Gas Use	363	MMscf/yr (based on 1065 btu/scf)

Pollutant	Natl Gas EF* (lb/MMbtu)	Natl Gas Emissions (tpy)	Coal Emissions (tpy)	Total Emissions (tpy)	NG EF source
CO	0.0235	4.5	47.3	51.9	AP42 1.4-1
NOx	0.1667	32.2	892.2	924.4	AP42 1.4-1
SO2	0.000588235	0.1	1720.7	1720.8	AP42 1.4-2
VOC	0.008529412	1.6	5.7	7.3	AP42 1.4-2
PM	0.00745098	1.4	92.6	94.0	AP42 1.4-2
PM10	0.00745098	1.4	21.3	22.7	AP42 1.4-2
PM25 filt			9.3	9.3	--
PM25 cond			38.2	38.2	--
PM25 Total	0.00745098	1.4	47.5	48.9	AP42 1.4-2
CO2	117.6	22,720	591,605	614,325	AP42 1.4-2
N2O	0.0022	0.4	7.6	8.0	AP42 1.4-2
CH4	0.0023	0.4	3.8	4.2	AP42 1.4-2
CO2e		22,861	594,032	616,893	--

*AP 42 factors Converted to lb/MMBtu based on HHV of 1020 btu/scf

Scenario #3: firing natural gas only

MMBtu total	4634812	MMBtu/yr
Gas Use	4352	MMscf/yr (based on 1065 btu/scf)

Pollutant	Natl Gas EF* (lb/MMbtu)	Natl Gas Emissions (tpy)	EF Source
CO	0.0235	54.5	AP42 1.4-1
NOx	0.1667	386.2	AP42 1.4-1
SO2	0.000588235	1.4	AP42 1.4-2
VOC	0.008529412	19.8	AP42 1.4-2
PM	0.00745098	17.3	AP42 1.4-2
PM10	0.00745098	17.3	AP42 1.4-2
PM25 Total	0.00745098	17.3	AP42 1.4-2
CO2	117.6	272,636	AP42 1.4-2
N2O	0.0022	5.1	AP42 1.4-2
CH4	0.0023	5.3	AP42 1.4-2
CO2e		274,328	--

*AP 42 factors Converted to lb/MMBtu based on HHV of 1020 btu/scf

Max PAE for each pollutant

Pollutant	tpy
CO	54.5
NOx	973.3

Step 4: Compare BAE to PAE

Pollutant	BAE (tpy)	Demand Growth (tpy)	PAE (tpy)	PAE - BAE (tpy)	Significance Level (tpy)
CO	46.0	-	54.5	8.5	100
NO_x	970.6	-	973.3	2.7	40
SO_2	1,845.3	-	1877.1	31.8	40
VOC	5.6	-	19.8	14.22	40
PM	82.4	-	101.0	18.6	25
PM_{10}	19.0	-	23.2	4.3	15
$PM_{2.5}$	41.9	-	51.8	9.9	10
CO_{2e}	611,826	-	648,035	36,210	75,000

Additional Notes

Note that this facility was previously determined not to qualify as an electric utility steam generating unit under the acid rain program. Therefore, the source is allowed to use the 10 year look-back period to define baseline actual emissions under Colorado Regulation No. 3, Part D, II.A.4.b

The projected actual period is determined to be 5 years for this project. Colorado Regulation No. 3, Part D, II.A.36.a would require a 10 year projected actual period if *"the project involves increasing the emissions unit's design capacity or its potential to emit of that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source."*

VOC is the only pollutant with an increase in PTE for this project. A comparison of BAE to PTE is also less than the significance level of 40 tpy, so the 5 year period is applicable:

PTE - BAE = 24.3 tpy - 5.6 tpy =	18.75	tpy