TECHNICAL REVIEW DOCUMENT
For
OPERATING PERMIT 01OPAD212

Trigen Colorado Energy Corporation Cogeneration Facility
At The Metro Wastewater Treatment Facility
Adams County
Source ID 0010097

Prepared November 2001
Jacqueline Joyce, Review Engineer
Revised January, March and April 2002

I. Purpose

This document will establish the basis for decisions made regarding the Applicable Requirements, Emission Factors, Monitoring Plan and Compliance Status of Emission Units covered within the Operating Permit proposed for this site. It is designed for reference during review of the proposed permit by the EPA and during Public Comment. The conclusions made in this document are based on information provided in the original application submittal of February 5, 2001, comments on the draft operating permit received March 18, 2002, a meeting (April 11, 2002) summary letter receive on April 17, 2002 and subsequent, e-mail correspondence and telephone conversations with the source. This narrative is intended only as an adjunct for the reviewer and has no legal standing.

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

The Metro Wastewater facility is a wastewater treatment facility which falls into the Standard Industrial Classification of 4952. The primary purpose of this facility is to treat wastewater. Primary treatment removes solids from wastewater through screening, grit removal and primary clarification. Secondary treatment uses microorganisms to remove suspended and dissolved organic and inorganic pollutants that remain after primary treatment. Solids generated during secondary treatment are removed by secondary clarification. Solids from primary and secondary clarification are subsequently subjected to intensive digestion in the anaerobic digestion process. Anaerobic digestion

produces a by-product waste gas (digester gas) that contains methane and carbon dioxide, along with smaller amounts of hydrogen sulfide. The digester gas is a good source of fuel. Previously the Metro Wastewater Reclamation District (MWRD) used digester gas, in addition to natural gas in engines and boilers to produce electrical energy and hot water which was used to heat the anaerobic digesters and building locations at the facility. The process is termed "cogeneration". However, in April of 1999, the MWRD and Trigen Colorado (Trigen) signed an agreement for Trigen to operate, maintain and upgrade the MWRD's cogeneration facility. As part of this agreement, Trigen purchased and installed two new gas turbines for the cogeneration facility. The wastewater treatment facility is the responsibility of the MWRD and was issued a separate operating permit (95OPAD072). Trigen is responsible for permitting and compliance associated with the cogeneration facility.

This cogeneration facility falls into the Standard Industrial Classification of 4939. As indicated previously, Trigen owns and operates two combustion turbine generator units and is responsible for operating four internal combustion engines that are owned by MWRD. Trigen is also responsible for the permitting and compliance of three boilers and seven flares that are owned and operated by MWRD.

The turbines and engines provide power for the facility and heat to the digester tanks and burn either natural gas or digester gas as fuel. Digester gas is generated by MWRD in the anaerobic digester tanks. These tanks maintain an oxygen-poor environment and an appropriate residence time with a suitable bacterial population to allow digestion of dissolved and suspended solids. This treatment process generates digester gas, which contains primarily methane (CH_4) and carbon dioxide (CO_2), with small quantities (generally less than 2,500 ppm) of hydrogen sulfide (H_2S). The boilers provide heat to the digester tanks and burn only natural gas as fuel, since the start-up of the first turbine. The flares are used to incinerate excess digester gas that cannot be used as fuel.

The facility is located in Adams county, within the Denver metro area. The area in which the plant operates has been designated as non-attainment for particulate matter less than 10 microns (PM_{10}). In addition, the Denver metro area is classified as attainment/maintenance for ozone and carbon monoxide. Under that classification, all SIP-approved requirements for 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.

This facility is within 100 km of a Federal Class I designated area, Rocky Mountain National Park and there are no states within 50 miles.

The wastewater treatment facility is subject to the provisions of Section 112(r) of the Federal Clean Air Act. 112(r) requires the submittal of a risk management plan (RMP) by June 20, 1999 and EPA's Risk Management Plan web page indicates that this plan was submitted on June 18, 1999. The provisions of Section 112(r) are not applicable to the cogeneration facility.

Trigen and MWRD are considered a single stationary source for purposes of prevention of significant deterioration (PSD) and major non-attainment area new source review (NSR) requirements. This source (Trigen and MWRD) is a major stationary source for purposes of non-attainment area NSR, since NO_X and SO_2 are precursors to PM_{10}. This source (Trigen and Metro) is considered a synthetic minor source for purposes of PSD review requirements. Facility wide (Trigen and MWRD) emissions are as follows:

Pollutant	**Potential to Emit (tons/yr)**			**Actual Emissions (tons/yr)**		
	Trigen	MWRD[1]	Facility	Trigen	MWRD	Facility
PM	17.26	0.43	17.69	4.12		4.12
PM_{10}	17.26	0.25	17.51	1.61		1.61
NO_X	86.85	19.27	106.12	44.25		44.25
SO_2	169.6	0.87	170.47	55.64		55.64
CO	99	3.67	102.67	44.8		44.8
VOC	12.6	14.25	26.85	5.3	12.95	18.25
H_2S	5.3		5.3	1.18		1.18
HAPS	1.79	8.67	10.46	0.74	3.49	4.23

[1]MWRD PTE includes permitted emission limits for an emergency generator that is not currently included in the Title V operating permit for that facility. A construction permit was issued for this unit on September 20, 2001.

Potential to emit for criteria pollutants is based on permitted emissions. Potential to emit for HAPS for both Trigen and MWRD is based on the Division's preliminary analysis conducted for the associated construction permits. Actual emissions, for the combustion sources (Trigen) are based on APENS submitted on February 5, 2001 by Trigen for the data year 2000. Note that the turbines operated for only a partial year in 2000. Actual emissions for the wastewater treatment facility are based on an APEN submitted on November 22, 2000 by MWRD for the data year 1999 and actual emissions for the gasoline tank at MWRD is based on an APEN submitted on January 20, 2001 for the data year 2000. Note that the emergency generator for MWRD has not operated for a full year and therefore actual emissions data has not yet been reported by MWRD.

III. Emission Sources

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

A. Two (2) Solar Centaur Model No. 40-T4700 GSC, Combustion Turbine Generator Units, Each Rated at 42.78 MMBtu/hr and Driving a 3515 KW Generator, Serial Nos. 4989C and 4998C. Natural Gas and Digester Gas Fired.

B. Four (4) Superior, Model No. 12SGTA, Internal Combustion Clean Burn Electric Generators (Cogeneration), Each Rated at 27.2 MMBtu/hr and Driving a 1.2 MW Generator, Serial Nos. 299899, 299909, 299919 and 299929. Natural Gas and Digester Gas Fired.

C. Three (3) Cleaver-Brooks, Model No. CB200X-300, Fire Tube Boilers, Each Rated at 12.5 MMBtu/hr, Serial Nos. L-61282, L-61281 and L-70086. Natural Gas Fired.

D. Seven (7) Varec, Model No. 239 Flares, Rated at 140.4 MMBtu/hr <u>Total</u>.

Discussion:

1. Applicable Requirements – The engines were installed and began operation in 1984. The catalytic converters were removed from all four engines because of clogging problems in 1989. The engines were permitted under Colorado Construction Permit 84AD057. Two of the three boilers were installed and began operation in 1977 and the third in 1981. The boilers were permitted under Colorado Construction Permits 11AD004-1 & –2 and 12AD973-1. Three of the seven flares were installed and began operation in 1977 and were modified in 1983. One flare was installed and began operation in 1981 and was modified in 1983. The remaining three flares were installed and began operation in 1983. The flares were permitted under Colorado Construction Permit C-12,973-2.

In December 1995, MWRD submitted a request to modify their construction permits for the combustion equipment, as SO_2 emissions from combustion of the digester gas were higher than previously believed. In addition, MWRD requested that all combustion sources be included on one permit. Permit 84AD057 was issued as an initial approval permit on December 30, 1998, however, MWRD petitioned for a hearing before the Air Quality Control Commission (AQCC) on the permit as they objected to various terms and conditions in the permit, particularly the short term (monthly) emission and fuel consumption limits and the requirement to install a continuous monitoring device to measure H_2S concentrations in the digester gas. The Division and MWRD reached an agreement on the permit terms and conditions and no hearing was held. A revised permit was issued to MWRD on June 29, 1999.

In April 1999, MWRD and Trigen Colorado entered into an agreement in which Trigen would modify and operate the cogeneration facility. The proposal consisted of adding

two new 3,515 kW turbines. As a result of this agreement, MWRD and Trigen submitted an application in May 1999 to modify the construction permit for the combustion sources and permit 84AD057 was issued as an initial approval permit on January 5, 2000. This permit includes the turbines,which began operation in September 2000. Trigen owns and operates the turbines and is responsible for operating the engines, which are owned by MWRD. Trigen is also responsible for the permitting and compliance of the three boilers and seven flares, which are owned and operated by MWRD. The due date of the first semi-annual monitoring report required by this operating permit will be more than 180 days after the turbines commenced operation. Therefore, the Division considers that the Responsible Official certification submitted with that report will serve as the self-certification for construction permit 84AD057 and the appropriate provisions of the construction permit have been included into this operating permit.

Permit 84AD057 identifies the following applicable requirements for the turbines, engines, boilers and flares:

- 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).

  Note that Colorado Regulation No. 1 does not identify the 20% opacity requirement as a condition that only applies during normal operation and EPA has objected, in comments on another operating permit, to the term “normal operations” applied to the 20% opacity standard. The specific operational activities subject to the 30% opacity requirement are also conditions that can be considered “normal operation”. Therefore, the language in the permit will not specify “normal operation”. In addition, in the permit the 30% opacity requirement will be written to include all the specific operational activities identified in Reg 1.

- This source shall be limited to the maximum consumption rates as listed below (condition 4)
  - Digester gas: 1,488 MMscf/yr and 372 MMscf/qtr
  - Natural gas: 96 MMscf/yr and 24 MMscf/qtr

    The quarterly consumption limits apply during the first year of operation of the turbines only. The turbines commenced operation in September 2000, therefore these requirements will not be included in the permit.

  - Digester gas combusted shall not have an H_2S concentration greater than 2000 ppmv, on a 3-hour average.

The current version of the construction permit (dated January 5, 2000) indicates that the H_2S concentration of the digester gas combusted shall not exceed 2000 ppmv. The previous version of the permit (dated June 29, 1999) did not specifically identify the 2000 ppmv H_2S concentration as a limit but specified that if the digester gas concentration (on a 12-month average) exceeded 2000 ppmv, the permit holder would take measures to lower the H_2S concentration. The current permit requires the source to take measures if the H_2S concentration (on a 3-hour average) approaches 2000 ppmv. The language in the current permit creates some problems because the H_2S concentration of the digester gas is measured where it is produced, after the digesters. At the point of measurement, the digester gas is wet. Wet digester gas is burned in the flares, but moisture is removed prior to burning the digester gas in the engines or flares, which means that the concentration of H_2S burned in the engines and flares is higher than the measured concentration. The Division considers that when the June 29, 1999 permit was revised to add the turbines, we made an error by specifying that the H_2S concentration limit applied to the digester gas as combusted. The measures taken to reduce the digester gas H_2S concentration would be taken in the digesters, where the digester gas is produced. Therefore it makes more sense to monitor the H_2S concentration where it is produced rather than where it is combusted. The Division will remove the word "combusted" from this condition. The Division considers that the H_2S concentration limit applies to the digester gas as it is produced (i.e. monitored after the digesters, as a wet gas).

- Compliance with the SO_2 emission limits is not directly correlated with the fuel consumption limits listed above. The source must demonstrate (via the compliance plan) that the sum of the SO_2 emissions from the consumption of digester gas is less than the limitations presented in condition 8 of the construction permit.

  The complete language of the above permit condition is not necessary, since the operating permit will specifically identify the method by which the source will monitor compliance with various permit conditions.

- APEN reporting requirements (condition 5).

  The APEN reporting requirements will not be identified in the permit as a specific condition but are included in Section IV (General Conditions) of the permit, condition 22.e.

- A source compliance test shall be conducted on both turbines to measure

the emissions rate(s) for SO_2, NO_X and CO in order to show compliance with the emission limitations in condition 8, the standards in condition 9 and the limitation in condition 14 of the construction permit.

Performance tests were conducted October 25 and 26, 2000 and testing indicated compliance with the limitations, therefore the requirement to conduct an initial performance test will not be included in the permit.

- This source is subject to the odor requirements in Reg 2 (condition 7).

  Typically combustion sources are not generally sources of odor but these combustion sources are located at a facility that may reasonably be expected to have odorous emissions. The operating permit issued to MWRD for the wastewater treatment processes includes the Reg 2 odor requirements in their operating permit and the permit requires a monthly scentometer reading as periodic monitoring. Therefore the Reg 2 odor requirements will not be specifically identified in the operating permit for Trigen. However, it should be noted that for all operating permits the odor requirements are in the general conditions of the permit (Section IV, Condition 14).

- Emissions of air pollutants from all turbines, engines, boilers and flares together shall not exceed the following limitations (condition 8):

PM	4.3 tons/quarter	and	17.26 tons/yr
PM_{10}	4.3 tons/quarter	and	17.26 tons/yr
SO_2	42.4 tons/quarter	and	169.60 tons/yr
NO_X	21.7 tons/quarter	and	86.85 tons/yr
VOC	3.2 tons/quarter	and	12.6 tons/yr
CO	24.8 tons/quarter	and	99.0 tons/yr
H_2S	1.3 tons/quarter	and	5.3 tons/yr

  The quarterly emission limits apply during the first year of operation of the turbines only. The turbines commenced operation in September 2000, therefore these requirements will not be included in the permit.

- The turbines are subject to the New Source Performance Standards of Regulation No. 6, Part A, Subpart GG, Standards of Performance for Stationary Gas Turbines (40 CFR Part 60 Subpart GG, as adopted by reference in Colorado Regulation No. 6, Part A), including, but not limited to the following (condition 9):
  - Emissions of NO_X from each turbine shall not exceed 201 ppmvd at 15% O_2, corrected to ISO conditions (40 CFR Part 60 Subpart GG § 60.322(a)(2))

    On June 27, 2001, monitor certification testing was performed at the Trigen Metro facility and a routine inspection was conducted

concurrently. The inspection report indicates that the NSPS NO_X standard included in the construction permit was determined incorrectly based on fuel gas information submitted, which indicated a high fuel gas nitrogen content. However, since the nitrogen in the fuel gas is free nitrogen (N_2), which EPA considers does not contribute to NO_X formation, and since the fuel bound nitrogen content was less than 0.0001 percent by weight, the NO_X standard must be revised. Based on the lack of fuel bound nitrogen, the NO_X standard for these turbines should be 151 ppmvd. This standard has been included in the permit.

- Emissions of SO_2 from each turbine shall not exceed 150 ppmvd at 15% O_2 **OR** fuel burned in each turbine shall not exceed of 0.8% by weight sulfur.
- Monitoring of operations per § 60.334.
- Test methods and procedures per § 60.335.

The specific applicable requirements in § 60.334 are daily (or custom schedule based on the characteristics of the fuel supply) monitoring of the sulfur content and nitrogen content of the fuel (§ 60.334(b)(2)) and excess emission reporting (§ 60.334(c)). The specific applicable requirements in § 60.335 are performance test requirements (§§ 60.335 (b) & (c)), fuel sampling ((§§ 60.335 (a), (d) & (e)) and alternatives (§ 60.335(f)).

Note that EPA has indicated in a policy memo dated August 14, 1987 that the nitrogen sampling may be waived for natural gas, since natural gas contains no fuel-bound nitrogen and since free nitrogen does not contribute appreciably to NO_X emissions. The fuel analysis of the digester gas conducted along with the performance testing for the turbines showed no significant fuel bound nitrogen (< 0.0001%) in the digester gas. Since as EPA as already indicated, free nitrogen does not contribute to NO_X emissions, therefore, the nitrogen sampling can be waived for digester gas. In a January 17, 2002 letter (see attached), EPA Region VIII indicated that analysis of nitrogen in natural gas and digester gas is not required.

- The turbines are also subject to the requirements in Regulation No. 6, Part A, Subpart A, specifically the following (condition 9):
  - Good practices (§ 60.11(d))
  - Circumvention (§ 60.12)

Note that a more extensive list of requirements from 40 CFR Part 60 Subpart A was included in the construction permit, however, these requirements, if still applicable, will be included in the permit as periodic

monitoring or under the continuous emission monitoring requirements and will not be specifically identified as requirements under the NSPS general provisions.

- The turbines are subject to the **State-only** New Source Performance Standards requirements of Regulation No. 6, Part B, Section II, Standards of Performance for New Fuel Burning Equipment including, but not limited to the following (condition 10):
  - Particulate matter emissions shall not exceed $0.5(FI)^{-0.26}$ lbs/MMBtu, where FI is the fuel input in MMBtu/hr (Reg 6, Part B, Section II.C.2)
  - Sulfur dioxide emissions shall not exceed 0.80 lbs/MMBtu (Reg 6, Part B, Section II.D.3.a)
  - Opacity of emissions shall not exceed 20% (Reg 6, Part B, Section II.C.3). Note that this requirement was not included in the construction permit.

  The construction permit only indicates that the turbines are subject to these requirements, however, it should be noted that one boiler is subject to the particulate matter and opacity requirements also, since one of the boilers was placed into service in 1981. The engines at this facility generate electricity directly but also waste heat from the engines are used to heat the digesters. The cogeneration capability of these units appears to indicate that these engines could meet the definition of "fuel burning equipment", although providing heat is not the sole purpose of these engines. However, it has been the Division's policy (see attached memo from Jim King, dated May 7, 1998) to consider that the fuel burning requirements do not apply to internal combustion engines. Therefore, the Division does not consider that the Reg 6, Part B requirements for fuel burning equipment apply to these engines.

  The NSPS general provisions (40 CFR Part 60 Subpart A) are adopted by reference in Colorado Regulation No. 6, Part B, Section I.A and therefore, the NSPS general provisions apply to the turbines and boiler No. 3 on a **State-only** basis. The permit will specifically include the good practices (§ 60.11(d)) and circumvention (§ 60.12) general provisions in the permit. The State-only NSPS general provision will be streamlined out of the permit for the turbines, since they are already subject to the NSPS general provisions on a state and federal basis.

- Particulate matter emissions from each boiler shall not exceed $0.5(FI)^{-0.26}$ lbs/MMBtu, where FI = fuel input in MMBtu/hr (condition 11 and Reg 1, Section III.A.1.b).

  Note that although the construction permit only indicates that the boilers are subject to this requirement, the Division considers the turbines to be

fuel burning equipment (turbines are specifically listed as fuel burning equipment in Reg 6, Part B, Section II) and therefore the turbines are also subject to this Reg 1 particulate matter requirement. In addition, as discussed above under the Reg 6, Part B, Section II applicable requirements, the engines are not considered fuel burning equipment and therefore the engines are not subject to this Reg 1 particulate matter requirement.

- The digester gas shall be sampled by a continuous monitor to determine H_2S concentrations. The average H_2S concentration shall be recorded hourly to show compliance with the 3-hour average. If the 3-hour average H_2S concentration approaches 2000 ppmv, the permit holder will take measures to lower the H_2S concentration in the digester gas. These measures may include adding ferric or ferrous chloride to the wastewater treatment system (condition 12).

- A continuous monitor to determine H_2S concentrations in the digester gas shall be installed maintained, calibrated and operated according to the procedures found in 40 CFR 60 as follows (condition 13):
  - An excess emissions and monitoring report shall be submitted semi-annually as outlined in § 60.7(c) and (d).
  - The continuous monitoring system shall be maintained and operated as stated in § 60.13.
  - The compliance plan required in condition 20 of the construction permit shall contain quality assurance (QA) and quality control (QC) procedures for the H_2S monitor.
  - Quality assured data shall be available for a minimum of 90% of the duration of the operation. For the periods, when such data is not available, the highest reading recorded during the previous 30-day period shall be used for determining the concentration.

    The construction permit specifies that the continuous monitoring system shall be maintained and operated as stated in § 60.13. The requirement to provide quality assured data for 90% of the duration of the operation conflicts with the requirements in § 60.13(e), which requires that the continuous monitoring system be operated at all times, except under certain conditions. Therefore, it was not appropriate for the Division to include the 90% requirement in the construction permit. This requirement will not be included in the operating permit.

    The Division approved the source's use of an alternative methodology for determining the H_2S concentration in the digester gas during the continuous monitoring system prove-out time frame. The source proposed to also use this methodology for future data replacement requirements. This method relies on twice per week

sampling. The Division considers that the source's proposed method provides more realistic data and therefore, that methodology will be included in the permit and is intended to supplement the above construction permit language regarding data replacement.

- The turbines are subject to Reasonably Available Control Technology (RACT) standards for carbon monoxide which shall be good combustion practices. Each turbine shall not exceed carbon monoxide emissions of 50 ppmv at 15% O_2 and ISO conditions (condition 14 and Reg 3, Part B, Section IV.D.2.d.(i)).

- The turbines are subject to Reasonably Available Control Technology (RACT) standards for Particulate Matter less than 10 microns which shall be good combustion practices (condition 15 and Reg 3, Part B, Section IV.D.2.d.(i)).

- "Good Combustion Practices" constitute monitoring and control of several operating parameters. These parameters include, but are not limited to, ambient temperature (T_o), combustion temperature (T_c) and heat rate. All relevant parameters and their optimal operating ranges for various combustion devices shall be identified, and included in the required operation and maintenance plan (condition 16).

- Prevention of Significant Deterioration (PSD) requirements shall apply to this source at any such time that this source becomes major solely by virtue of a relaxation in any permit condition. Any relaxation that increases the potential to emit above the applicable PSD threshold will require a full PSD review of the source as though construction had not yet commenced on the source. The source shall not exceed the PSD threshold until a PSD permit has been granted (condition 17 and Reg 3, Part B, Section IV.D.3.b.(iv).

  The above requirement will not be included in the operating permit, since no action (i.e. PSD review) is required until the underlying conditions are relaxed above the major stationary source level for PSD. Note that since this construction permit was a synthetic minor for a major modification for purposes of major non-attainment area review, the relaxation language also applies in accordance with Reg 3, Part B, Section IV.D.2.b.(ii)); however, it will not be included for the same reasons as indicated above for the PSD relaxation language.

- Emissions from all insignificant activities related to the modification contained in this permit shall not exceed one ton per year of SO_2. The applicant shall track emissions from all insignificant activities related to the modification contained in the permit on a yearly basis. This information

shall be made available to the Division for inspection upon request. For the purposes of this condition, insignificant activities shall be defined as any activity or equipment related to the modification contained in this permit which emits any amount but does not require an APEN (condition 18).

- Prior to final approval being issued, the applicant shall submit to the Division for approval an operating and maintenance plan for all control equipment and control practices, and a proposed record keeping format that will outline how the applicant will maintain compliance on an ongoing basis with the requirements of this permit (condition 20 and Reg 3, Part B, Section IV.B.2).

  This requirement will not be included in the operating permit, since periodic monitoring requirements will be included to monitor compliance with the requirements in this permit. An operating and maintenance plan shall be required to document "good combustion practices" as required by condition 16 of the construction permit.

- Construction of the turbines must commence within 18 months of initial approval permit issuance date or within 18 months of date on which such construction or activity was scheduled to commence as stated in the application. If commencement does not occur within the stated time the permit will expire on July 5, 2001 (condition 21).

  Since the turbines commenced operation in September 2000, this condition will not be included in the operating permit.

- Within one hundred and eighty days (180) after commencement of operation, 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 (condition 22).

  The Division considers that the submittal of the first semi-annual monitoring report, signed by the Responsible Official, satisfies the requirement for self-certification that the source can comply with the conditions in this construction permit, therefore, this requirement will not be included in the permit.

Although not specifically identified in Colorado Construction Permit 84AD057, the emission units are subject to the following applicable requirements:

- SO_2 emissions from each turbine shall not exceed 0.8 lbs/MMBtu (Reg 1, Section VI.B.4.c.(i)).

The Common Provisions Regulation defines an incinerator as "any equipment, device, or contrivance used for the destruction of solids, liquids or gaseous wastes by burning, other than devices commonly called wigwam waste burners used exclusively to burn wood wastes." According to this definition, the flares are considered incinerators. Therefore, the flares are subject to the following applicable requirements:

- Particulate matter emissions shall not exceed 0.1 grains/standard cubic feet, dry corrected to 12 percent carbon dioxide (Colorado Regulation No. 1, Section III.B.2.a).

- Since all the flares were either constructed or modified after January 30, 1979, these flares are subject to the **State-only** incinerator requirements in Reg 6, Part B, Section VII, as follows:
  - Opacity of emissions shall not exceed 20% (Reg 6, Part B, Section VII.C)

  The Reg 6, Part B, Section VII requirements include particulate matter standards and specific requirements for monitoring and test methods. However, the Division's policy memo PS 99-2, dated May 6, 1999 (see attached), indicates that since these particulate matter standards are based on the charging rate, which is specified in tons/yr, the Division considers that these standards were not intended to apply to flares that were only burning waste gases, since a tons/yr charge rate is not practical for that type of incinerator. Since the particulate matter standards do not apply, the Division considers that the monitoring and testing requirement also do not apply.

- The flares are also subject to the NSPS general provisions (40 CFR Part 60 Subpart A), which are adopted by reference in Colorado Regulation No. 6, Part B, Section I.A, specifically the following). These requirements are **State-only** requirements.
  - Good practices (§ 60.11(d))
  - Circumvention (§ 60.12)

  In addition, the NSPS general provisions contain general requirements for control devices in 40 CFR Part 60 Subpart A § 60.18, including requirements for flares (§ 60.18(b)). The Division considers that these requirements do not apply to the flares, since the requirements in 40 CFR Part 60 Subpart A § 60.18 apply only to control devices used to comply with specific requirements. The flares at Metro are not used to comply with any emission limitations or requirements but are used to get rid of digester gas when it cannot be used as fuel.

The Division considers that these flares are not subject to the general NSPS incinerator requirements in 40 CFR Part 60 Subpart E, as adopted by reference in Reg 6, Part A, since the definition of an incinerator is "any furnace used in the

process of burning solid waste for the purposes of reducing the volume of the waste by removing combustible matter". The definition does not appear to address any incinerator burning gaseous waste only, as the phrase "for the purposes of reducing the volume" does not make sense for an incinerator burning gaseous waste. Secondly, the definition of solid waste, in 40 CFR Part 60 Subpart E does not include any gaseous waste.

Streamlining of Applicable Requirements

Opacity

The turbines, flares and boiler No. 3 are subject to the Reg 1 20% opacity requirement and the Reg 1 30% opacity requirement for certain specific operational activities. The Reg 1 20% opacity requirement applies at all times, except for certain specific operating conditions under which the Reg 1 30% opacity requirement applies. The turbines and boiler No. 3 are also subject to the state-only Reg 6, Part B, Section II 20% opacity requirement. The flares are also subject to the state-only Reg 6, Part B, Section VII.C 20% opacity requirement. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. 40 CFR Part 60 Subpart A § 60.11(c) specifies that the opacity requirements are not applicable during periods of startup, shutdown and malfunction. The Reg 1 20%/30% requirements are more stringent than the Reg 6 Part B opacity requirements during periods of startup, shutdown and malfunction. While the Reg 6 20% opacity requirement is more stringent during fire building, cleaning of fire boxes, soot blowing, process modifications and adjustment or occasional cleaning of control equipment. Therefore, since no one opacity requirement is more stringent than the other at all times, all three opacity requirements are included in the operating permit. See the attached grid for a clarified view on the opacity requirements and their relative stringency

It should be noted that since the turbines, flares, and boiler No 3 burn digester gas or natural gas as fuel, the Division will presume, in the absence of credible evidence to the contrary, that these units are in compliance with all of the opacity requirements.

PM

The turbines and boiler No. 3 are subject to the Reg 1 particulate matter requirements and the state-only, Reg 6, Part B particulate matter requirements. The particulate matter requirements in both Reg 1 and Reg 6, Part B are the same standard. The Reg 1 particulate matter requirements apply at all times. Reg 6, Part B, Section I.A, adopts, by reference, the 40 CFR Part 60 Subpart A general provisions. Although not specifically stated in the general provisions, the Division has concluded after reviewing EPA determinations that the NSPS standards are not applicable during startup, shutdown and malfunction, although any excess emissions during these periods must be reported in the excess emission reports. Specifically, EPA has indicated (4/18/75, determination control no. A007) that when 40 CFR Part 60 Subpart A § 60.11(d) was developed "...it was recognized that sources which ordinarily comply with the standards

may during periods of startup, shutdown and malfunction unavoidably release pollutants in excess of the standards." In addition, EPA has also indicated (5/15/74, determination control number D034) that "[s]ection 60.11(a) makes it clear that the data obtained from these reports are not used in determining violations of the emission standards. Our purpose in requiring the submittal of excess emissions is to determine whether affected facilities are being operated and maintained 'in a manner consistent with good air pollution control practices for minimizing emissions' as required by 60.11(d)." Therefore, the Division considers that the Reg 6, Part B particulate matter requirements do not apply during periods of startup, shutdown and malfunction. As a result, the Reg 6, Part B requirements have been streamlined out of the permit.

SO_2

The turbines are subject to the Regulation No. 1 and No. 6, Part B SO_2 standards. The SO_2 requirements in both Reg 1 and Reg 6, Part B are the same standard. The Regulation No. 6, Part B requirement is a state-only requirement and since Regulation No. 6, Part B incorporates the NSPS General Provisions (40 CFR Part 60 Subpart A), the SO_2 requirements do not apply during startup, shutdown and malfunction (as discussed in the PM streamlining section above). Therefore, the Regulation No. 1 SO_2 requirement is more stringent than the Regulation No. 6, Part B requirement and the Regulation No. 6, Part B requirements will be streamlined out of the permit.

Miscellaneous

The turbines are subject to the NSPS general provisions (40 CFR Part 60) on a federal and state basis (the units are subject to 40 CFR Part 60 Subpart GG) and on a state-only basis (the units are subject to Reg 6, Part B, Section II and the NSPS general provisions are adopted by reference in Reg 6, Part B, Section I.A). Therefore, the Division will streamline the state-only NSPS general provisions out of the permit in favor of the state and federal NSPS general provisions.

2. Emission Factors – In the Title V operating permit application, the source proposed emission factors or calculation methodologies to monitor compliance with the emission limitations. For the most part the Division has accepted these emission factors. The emission factors that will be identified in the permit are as follows:

Unit	Emission Factor (lbs/MMBtu)					Source of Emission Factor
	PM	PM_{10}	VOC	NO_X	CO	
Turbines						
Natural Gas	6.6×10^{-3}	6.6×10^{-3}	0.0683	0.589	0.119	VOC, NO_X and CO emission factors are based on manufacturer's guarantee. PM and PM_{10} emission factors are from AP-42 (dated 4/00) Section 3.1, Tables 3.1-2a & 3.1-2b
Digester Gas	1.2×10^{-2}	1.2×10^{-2}	0.037	0.232	0.129	
Engines						
Natural Gas	9.99×10^{-3}	9.99×10^{-3}	0.118	4.08	0.557	For natural gas, emission factor are from AP-42 (dated 7/00), Section 3.2, Table 3.2-2. For digester gas, emission factors are from stack tests conducted 6/5 & 6/95 (PM, PM_{10} & VOC from engine 2, low load and NO_X & CO from engines 3 & 4, high load).
Digester Gas	7.36×10^{-3}	7.36×10^{-3}	2.19×10^{-4}	0.308	0.454	
Boilers[1]						
Natural Gas	7.45×10^{-3}	7.45×10^{-3}	5.39×10^{-3}	0.098	0.082	Emission factors are from AP-42 (dated 3/98), Section 1.4, Table 1.4-1
Flares[2]						
Digester Gas	1.23×10^{-3}	1.23×10^{-3}	5.39×10^{-3}	3.33×10^{-2}	2.80×10^{-2}	PM, PM_{10}, NO_X and CO emission factors are from stack test conducted on 6/7/95 (for PM, PM_{10} & NO_X from boiler 1, normal load, for CO from boiler 3, normal load). VOC emission factor is from AP-42 (dated 3/98), Section 1.4, Table 1.4-1

[1]The AP-42 emission factors for the boilers are in lbs/MMscf but were converted to lbs/MMBtu by dividing by a heat content of 1020 MMBtu/MMscf for natural gas.
[2]The VOC AP-42 emission factor is in lbs/MMscf emission factor but was converted to lbs/MMBtu by dividing by a heat content of 1020 MMBtu/MMscf for natural gas.

The manufacturer's guarantees for the turbines were provided in values of lbs/hr. In general, the Division does not approve the use of emission factors in lbs/hr, since such types of emission factors imply that the emission rate is the same regardless of whether

the unit is operated at high or low loads. Therefore, the Division converted the manufacturer's emission factors to factors in lbs/MMBtu by dividing the lbs/hr number by the heat input rate indicated in the manufacturer's guarantee sheets provided in the Title V permit application (36.05 mmBtu/hr for digester gas and 35.42 MMBtu/hr for natural gas). Note that the manufacturer's guarantees are more conservative than the emission factors predicted by the stack test conducted on the turbines on October 25 and 26, 2000 using digester gas as fuel. In addition, the manufacturer's emission factors are more conservative than the emission factors provided in AP-42.

In addition, when burning gaseous fuels, either digester gas or natural gas, the Division considers that it is likely that there will be no particulate matter emissions > 10 microns, so the PM and PM_{10} emission factors should be the same. Therefore, for the digester gas and natural gas, the same emission factor for PM and PM_{10} will be included in the permit. The most conservative emission factor proposed by Trigen was included in the permit as the PM and PM_{10} emission factor.

<u>SO_2 Emissions:</u>

When burning natural gas, the source proposed to use the following emission factors:

Unit	Emission Factor (lbs/MMBtu)	Source of Emission Factor
Turbines	3.4×10^{-3}	AP-42, Section 3.1, Table 3.1-2a (dated 4/00)
Engines	5.88×10^{-4}	AP-42, Section 3.2, Table 3.2-2 (dated 7/00)
Boilers	5.88×10^{-4}	AP-42, Section 1.4, Table 1.4-1 (dated 3/98)

When burning digester gas, SO_2 emissions will be calculated using the following equation:

SO_2 (tons/mo) = SO_2 engines + SO_2 turbines + SO_2 flares

<u>Engines</u>

$$SO_2 \text{ (tons/mo)} = \frac{[Q_E \times C_d \times \text{lbmole } H_2S/385 \text{ scf } H_2S \times 1 \text{ lbmole } SO_2/\text{lbmole } H_2S \times 64 \text{ lb } SO_2/\text{lbmole } SO_2]}{2000 \text{ lbs/ton}}$$

<u>Turbines</u>

$$SO_2 \text{ (tons/mo)} = \frac{[Q_T \times C_d \times \text{lbmole } H_2S/385 \text{ scf } H_2S \times 1 \text{ lbmole } SO_2/\text{lbmole } H_2S \times 64 \text{ lb } SO_2/\text{lbmole } SO_2]}{2000 \text{ lbs/ton}}$$

<u>Flares</u>

$$SO_2 \text{ (tons/mo)} = \frac{[Q_F \times C_W \times \text{lbmole } H_2S/385 \text{ scf } H_2S \times 1 \text{ lbmole } SO_2/\text{lbmole } H_2S \times 64 \text{ lb } SO_2/\text{lbmole } SO_2]}{2000 \text{ lbs/ton}}$$

Where: Q_E = Quantity of digester gas combusted in the engines, in MMscf/mo, at 1 atm and 68°F
Q_T = Quantity of digester gas combusted in the turbines, in MMscf/mo, at 1 atm and 68°F
Q_F = Quantity of digester gas combusted in the flares, in MMscf/mo, at 1 atm and 68°F

C_W = H_2S Concentration of digester gas as measured (ppmv, scf H_2S/MMscf gas). This is wet gas.
C_D = H_2S Concentration of dry digester gas. $C_D = C_W/0.90$

This equation is based on the volume of digester gas at the standard conditions in 40 CFR part 60 Subpart A § 60.2 (1 atm, 68°F). The digester gas measured is wet. The digester gas burned in the engines and flares is compressed and filtered to remove the moisture. Trigen and MWRD have indicated that the digester gas moisture content typically varies between 4% and 7%. The above calculations conservatively presume that the digester gas moisture content is 10%. This equation assumes that all of the H_2S in the digester gas is converted to SO_2.

<u>H_2S Emissions (only when digester gas is burned):</u>

H_2S (tons/mo) = H_2S engines + H_2S turbines + H_2S flares

<u>Engines</u>

$$H_2S \text{ (tons/mo)} = \frac{[(1-0.96) \times Q_E \times C_d \times \text{lbmole } H_2S/385 \text{ scf } H_2S \times 34 \text{ lb } H_2S/\text{lbmole } H_2S]}{2000 \text{ lbs/ton}}$$

<u>Turbines</u>

$$H_2S \text{ (tons/mo)} = \frac{[(1 - 0.96) \times Q_T \times C_d \times \text{lbmole } H_2S/385 \text{ scf } H_2S \times 34 \text{ lb } H_2S/\text{lbmole } H_2S]}{2000 \text{ lbs/ton}}$$

<u>Flares</u>

$$H_2S \text{ (tons/mo)} = \frac{[(1 - 0.96) \times Q_F \times C_W \times \text{lbmole } H_2S/385 \text{ scf } H_2S \times 34 \text{ lb } H_2S/\text{lbmole } H_2S]}{2000 \text{ lbs/ton}}$$

The variables have the same definitions as discussed above under the discussion for calculating SO_2 emissions when burning digester gas. This equation assumes that 96% of the H_2S is converted and emitted as SO_2 and 4% is emitted as H_2S.

3. Monitoring Plan – Compliance with the annual emission and gas consumption limitations shall be monitored by calculating emissions and recording fuel consumption monthly. Compliance with the particulate matter and opacity limitations shall be presumed, in the absence of credible evidence to the contrary, whenever natural gas is used as fuel.

Typically for sources subject to an NSPS standard the Division requires that performance tests be conducted within the first year and within the last 18 months of the permit term to determine compliance with the NSPS emission limitations, unless such emission units are equipped with continuous emission monitoring systems. The turbines are subject to NSPS GG standards. However, since a performance test was conducted for the NSPS NO_X limit in June 2001, the Division will only require that a performance test be conducted in the last 18 months of the permit term. When the performance test was conducted for the NSPS NO_X limit, the source also conducted a performance test for the CO RACT limit. Therefore, the Division will also require that a

performance test for the CO RACT limit be conducted during the last 18 months of the permit term.

NSPS GG also sets requirements for SO_2 (ppmv or fuel limitation) and requires that fuel be sampled for sulfur content. NSPS GG requires that fuel be sampled daily or on a custom schedule based on the characteristics of the fuel supply. The source submitted custom fuel schedules to EPA for approval and the Division has included these custom fuel schedules in the permit. The custom fuel schedules were approved by EPA in a letter dated January 17, 2002.

The concentration of H_2S in the digester gas is limited to 2000 ppmv and compliance with this requirement shall be monitored by installing, calibrating and operating a continuous H_2S monitoring system. The continuous monitoring system is required to meet the requirements in 40 CFR Part 60 and is subject to semi-annual excess emission reporting requirements. The construction permit requires that quality assured data be available for a minimum of 90% of the duration of the operation and provided requirements on replacing data when quality assured data is not provided. In their Title V permit application, the source provided an alternative method to obtain H_2S concentration data when the continuous H_2S monitoring system is down. Since the source's alternate method provides more realistic data, the Division has included that language in the permit and considers that the source's proposed language supplements the data replacement requirements specified in the construction permit. In addition, the 90% data availability requirement was removed as it conflicts with the NSPS requirements for operating the continuous emission monitoring systems continuously.

Compliance with the SO_2 emission limitations (lbs/mmBtu) for the turbines shall be presumed, in the absence of credible evidence to the contrary whenever natural gas is used as fuel and the H_2S concentration of the digester gas meets the 2000 ppmv limitation.

4. Compliance Status – The source indicated that these emission units are in compliance with all applicable requirements.

IV. Insignificant Activities

General categories of insignificant activities include: chemical storage tanks or containers (< 500 gal), chemical storage areas (< 5,000 gal), storage of butane, propane and LPG (< 60,000 gal), lube oil storage tanks (< 40,000 gal), venting of compressed natural gas, butane or propane cylinders (< 1 gal), fuel burning equipment for heating (< 10 mmBtu/hr) and non-road engines (limited size or hours).

The additional categories of insignificant activities identified in the Operating Permit application are as follows:

Chemical storage tanks less than 500 gal (Reg 3 Part C.II.E.3.n)

Cooling water loop treatment chemicals (direct feed from two (2) 55-gal drums and one (1) 5-gal drum)
Water softener treatment system (open air mixing tank for make-up salt solution)
Engine dipping tank (sodium hydroxide, 215-gal for overhaul only)

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

Lubrication oil storage (55-gal drums and 280-gal portable totes, variety of lubricant greases)
Engine dipping tank (sodium hydroxide, 600 gal for overhaul only)
Engine dipping rinse tank (water, 215-gal for overhaul only)

Storage of butane, propane or LPG in tanks < 60,000 gal (Reg 3 Part C.II.E.3.zz)

Two (2) staged 30 lb propane cylinders (ignition fuel for turbines 5 and 6, normally not vented)

Storage of lube oil in tanks < 40,000 gal (Reg 3 Part C.II.E.3.aaa)

280-gal portable totes (engine oil)
Two (2) 400 gal lubrication oil sumps (one for each turbine)
Four (4) 300-gal lubrication oil sumps (one for each engine)

Venting of compressed natural gas, butane or propane gas cylinders < 1 gal (Reg 3 Part C.II.E.3.bbb)

Butane fueled torches (used in soldering activities)

Fuel burning equipment < 10 mmBtu/hr used solely for heating (Reg 3 Part C.II.E.3.ggg)

Hot water heating

Nonroad Engines - limited hours or size (Reg 3 Part C.II.E.3.xxx)

One (1) 3 hp gasoline driven portable sump pump
One (1) 10 hp, 6259 watt, gasoline driven portable generator

V. Alternative Operating Scenarios

In their Title V permit application, the source indicated that they had cold cleaner solvent vats located at their facility and the Division included applicable requirements for these types of units in the draft permit. In their comments on the draft permit received on

March 18, 2002, the source indicated that there was some confusion on their part and the stationary washer and rinse tank located at their facility is not subject to the requirements in Reg 7, Section X, since the washer uses a sodium hydroxide cleaning solution. Trigen does not have any cold cleaner solvent vats on site but have indicated that from time to time they may bring a unit in that meets the requirements in Regulation No. 3, Part A, Section II.D.4.b.(vi) for small remote reservoir cold solvent degreasers. These units are exempt from APEN reporting requirements and such a unit meets the requirements in Colorado Regulation No. 7, Section X.B. Trigen did indicate that they may wish to bring in a unit that was not considered a "small remote reservoir cold solvent degreaser" and wished to have that flexibility in their permit. The Division included an alternative operating scenario for bringing in a cold cleaner solvent vat for temporary use at the facility. In this case, temporary has been defined as 120 days in any twelve month period.

VI. Permit Shield

The source identified and justified a list of non-applicable requirements that they wished to be specifically shielded from. Those requirements that the Division concurred were not applicable were included in the permit shield and a justification is provided in the permit. The following discussion addresses the non-applicable requirements that Trigen requested to be shielded from but that the Division did not include in the permit shield.

The source requested the permit shield for the National Emission Standards for Hazardous Air Pollutants for Source Categories (40 CFR Part 63). The source's justification is that these units do not satisfy any applicability requirements for these standards and no reconstruction or modifications have been made that would trigger NESHAP applicability. The Division has not included this shield because the Division requires sources to specifically identify the non-applicable requirements that a source wishes to be shielded from, as well as provide a justification. Therefore, the source would need to identify each subpart of 40 CFR Part 63 and provide a justification for that subpart. In addition, the Division believes that it is inappropriate to include requirements that clearly do not apply to the facility (e.g. the shipbuilding MACT). Therefore, if the source would like the permit shield for those MACT standards germane to their facility (i.e. POTW or halogenated solvent cleaners) the Division is willing to grant such a shield provided the requirements are specifically identified and justified.

The source requested the permit shield from the Prevention of Significant Deterioration requirements in 40 CFR 52.21 (Colorado Regulation 3, Part B, Section IV.D.3). The source's justification in the permit application states that these requirements are not applicable as no modifications were made that would trigger PSD applicability. In comments received on another operating permit, EPA indicated that the Division could not grant the shield for PSD review requirements, unless the source was an existing source prior to August 7, 1977. Since equipment has been added to the facility after August 7, 1977, the Division cannot grant the permit shield for the PSD review requirements.

The source requested the permit shield for the requirements in 40 CFR Part 60 Subpart Kb (Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984). The justification provided by the source indicated that the facility has storage vessels with a capacity less than 42,910 gallons and which store liquids with a maximum true vapor pressure less than 15.0 kPa **or** have storage vessels with a capacity less than 10,000 gallons. The Division is willing to grant the shield if all the volatile organic liquid storage vessels have a capacity less than 10,000 gallons. However, storage vessels with a capacity less than 42,910 gal and storing liquids with a maximum true vapor pressure less than 15.0 kPa are subject to portions of 40 CFR Part 60 Subpart Kb (specifically §§ 60.116b(a) and (b)) and the shield cannot be granted for this justification. In their comments on the draft permit received on March 18, 2002, Trigen indicated that the tanks at the facility that are potentially subject to the requirements in 40 CFR Part 60 Subpart Kb are not assests owned by Trigen but by MWRD. Trigen provided a list of the potentially subject tanks and all tanks appear to have a capacity less than the applicability level of 40 cubic meters (10,567 gal). However, one tank was very close to the applicability level (estimated at 10,380 gal) and the Division requested more information from MWRD on the tank capacity to determine whether the tank would actually be subject to the requirements. MWRD submitted information to the Division indicating that the tank in question has a design capacity greater than 40 cubic meters. However, this tank has been cleaned, taken out of service and all associated piping has been blinded. Therefore, since this tank is out of service and is not storing volatile organic liquids, this tank is not subject to the requirements in 40 CFR Part 60 Subpart Kb. Therefore, the Division will grant the permit shield for the requirements in 40 CFR Part 60 Subpart Kb.

The source requested that flares 1 through 3 be granted the permit shield for the state-only requirements in Colorado Regulation No. 6, Part B, Section VII. The justification provided by the source indicated that flares 1 through 3 commenced construction and were not modified after January 30, 1979. The permit shield was not granted because information in the Division's master files indicate that these flares were modified in 1983.

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

- **State-only –** particulate matter ($0.5(FI)^{-0.26}$) requirement **for the turbines and boiler No. 3 only** (Reg 6, Part B, Section II.C.2), streamlined out since Reg 1 particulate matter requirement is more stringent.
- **State-only –** 0.80 lbs/MMBtu SO_2 requirement **for the turbines** (Reg 6, Part B, Section II.D.3.a), streamlined out since Reg 1 SO_2 requirement is more stringent.
- State-only – NSPS general provisions requirements **for the turbines** (Reg 6, Part B, Section I.A), streamlined out since the turbines are also subject to the NSPS general provisions on a state and federal basis.

VII. Compliance Assurance Monitoring

The compliance assurance monitoring (CAM) requirements in 40 CFR Part 64, as adopted by reference in Colorado Regulation No. 3, Part C, Section XIV apply to emission units equipped with control devices that are necessary to meet emission standards. As discussed previously, the flares are not used as control devices but are used to get rid of excess digester gas that cannot be used in either the turbines or engines. In addition, the permit specifies that when the H_2S concentration of the digester gas approaches 2000 ppmv that the source shall take measures to lower the concentration of H_2S in the digester gas. Although measures taken to lower the H_2S concentration in the digester gas will reduce emissions and allow the source to comply with their SO_2 and H_2S emission limitations, such measures are not considered a control device subject to the CAM requirements. Under CAM, "a control device is equipment… that is used to destroy or remove air pollutant(s) prior to discharge to the atmosphere… For purposes of [CAM], a control device does not include passive control measures that act to prevent pollutants from forming". The addition of ferric or ferrous chloride to the wastewater treatment process to reduce the formation of H_2S in the digester gas is therefore not considered a control device. Therefore, no emission units addressed in this permit are equipped with control devices and the Compliance Assurance Monitoring (CAM) requirements to not apply to any emission units at this facility.