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CONSTRUCTION PERMIT AMENDMENT

**ORIGINAL PERMIT TO MODIFY AN
AIR CONTAMINANT SOURCE
ISSUED ON JULY 8, 1999**

&

**ORIGINAL PREVENTION OF SIGNIFICANT DETERIORATION (PSD)
PERMIT TO MODIFY AN
AIR CONTAMINANT SOURCE
ISSUED ON JULY 2, 2003:**

IBP, Inc.
PO Box 515
Dakota City, NE 68731

&

IBP, Inc.
800 Stevens Port Drive, Suite 710
Dakota Dunes, SD 57049-8710

FOR THE SPECIFIC MODIFICATION OF:

Revision of Fuel Limits for Five Johnston Boiler Co. Boilers
&
The Wastewater Treatment Plant

LOCATED AT:

Highway 35, IBP Avenue
Dakota City, Dakota County, NE 68731

ARE HEREBY AMENDED AS FOLLOWS:

- Change the facility name from IBP, Inc. to Tyson Fresh Meats, Inc.;
- Allow combustion of biogas in Boiler #5; and
- Decrease sulfur content limit of No. 2 fuel oil from 0.5% to 0.25% by weight

The amendments to Conditions XIII.(B), (C), (G)(1) and (G)(2) of the construction permit issued July 8, 1999, and Conditions XIII.(B), (D), (G)(1), (G)(2), (G)(3), (I)(4) and (I)(5) of the PSD construction permit issued July 2, 2003, addressed herein do not trigger any additional requirements under Nebraska Title 129. No other terms or conditions of the original construction permits issued July 8, 1999, and July 2, 2003, are being revised or otherwise amended by this document.

All other provisions of the original issued permits are still in effect, and in concert with this construction permit amendment, constitute the effective construction permits. This construction permit amendment shall be attached to each original construction permit and maintained with it henceforth.

The construction permit issued July 8, 1999, shall be amended as follows:

Condition XIII.(B) now reads:

- (B) Natural gas, propane and No. 2 fuel oil shall be the only fuels combusted in the boilers, except that biogas combustion shall also be allowed in Boiler #5. There are no quantity limits on natural gas and biogas.

Condition XIII.(C) now reads:

- (C) A flow meter for natural gas and propane and a flow meter for No. 2 fuel oil shall be installed on the fuel supply lines for each boiler unless EPA Region VII approves an alternative approach for demonstrating compliance with Condition XIII.(G)(4). A flow meter for biogas shall be installed on the biogas supply line for Boiler #5. The meters shall be calibrated at least once per year.

Condition XIII.(G)(1) now reads:

- (1) All No. 2 fuel oil combusted shall comply with the specifications in ASTM D396-78, "Standard Specifications for Fuel Oils" {40 CFR 60.41c}. Sulfur content of the No. 2 fuel oil shall be limited to 0.25 weight percent {Title 129, Chapters 18 and 19}.

Condition XIII.(G)(2) now reads:

- (2) Compliance with Condition XIII.(G)(1) may be demonstrated with fuel supplier certifications. These certifications shall include the following for each No. 2 fuel oil delivery:
 - (a) The name of the No. 2 fuel oil supplier;
 - (b) A statement from the fuel oil supplier that the No. 2 fuel oil complies with ASTM D396-78.
 - (c) The sulfur content of the No. 2 fuel oil and the method used to determine the sulfur content.

The construction permit issued July 2, 2003, shall be amended as follows:

Condition XIII.(B) now reads:

- (B) The three new anaerobic lagoons (#9, #10, and #11) shall be equipped with sealed covers. The biogas stream from the three new covered lagoons shall be routed to a packed bed scrubber connected to a flare and/or Boiler #5 as required in Condition XIII.(D).

Condition XIII.(D) now reads:

- (D) Emissions from the two older lagoons, (#7 and #8), and the three new covered lagoons (#9, #10, and #11) shall be controlled as follows:
- (1) A packed bed scrubber, identified as Scrubber WT-C1, shall be used to remove TRS from the biogas stream.
 - (a) Scrubber WT-C1 shall be operated at all times the associated anaerobic lagoons are in operation except when maintenance is performed on the scrubber. During maintenance on Scrubber WT-C1, biogas shall be stored under the lagoon covers by shutting off biogas flow with valves. The lagoon covers shall be inspected for leaks and repaired as necessary prior to performing maintenance on the scrubber.
 - (b) Scrubber WT-C1 shall be properly installed, operated, and maintained. Manufacturer's instructions or equivalent operating instructions shall be kept on site and readily available to Department representatives.
 - (c) The biogas piping from Scrubber WT-C1's outlet shall be equipped with a Total Sulfur CEM to monitor the TRS content of the biogas stream exiting Scrubber WT-C1. The source shall prepare a preventative maintenance plan for the Total Sulfur CEM that shall be kept on site and readily available to Department representatives. The Total Sulfur CEM shall comply with the requirements of 40 CFR 60.13, including the requirements of 40 CFR 60 Appendix B Performance Specification 5 and Appendix F, unless written approval is obtained from the Department.
 - (d) The biogas piping from Scrubber WT-C1 to the flare and to Boiler #5 shall each be equipped with an operational flow meter to record the biogas flow rate. The flow meters shall comply with the requirements of 40 CFR 60.13, including the requirements of 40 CFR 60 Appendix B Performance Specification 6 and Appendix F, unless written approval is obtained from the Department.
 - (e) The biogas piping from Scrubber WT-C1's outlet shall be equipped with a fuel gas BTU analyzer meeting the specifications provided with the March 13, 2000 construction permit application. The analyzer shall be properly installed and operated; calibration and maintenance of the analyzer shall follow the protocol submitted to the Department. Manufacturer's instructions or equivalent operating instructions shall be kept on site and readily available to Department representatives.
 - (2) The source shall use either a flare and/or Boiler #5 to combust the TRS remaining in the biogas after Scrubber WT-C1.
 - (a) The flare and/or Boiler #5 shall be operated at all times the associated anaerobic lagoons are in operation except when maintenance is performed on Scrubber WT-C1 as described in Condition XIII.(D)(1)(a).

- (b) The flare and Boiler #5 shall be properly installed, operated, and maintained. Manufacturer's instructions shall be kept on site and readily available to Department representatives.
- (c) The flare shall be equipped with a thermocouple connected to a data recorder capable of verifying continuous operation.
- (d) The flare shall be equipped with an alarm connected to an automatic telephone dialer to notify plant personnel of biogas flow to the flare when no combustion is taking place. The source is required to notify the Department in writing of any malfunction of the flare causing excess emissions for more than 1 hour within 48 hours of the malfunction in accordance with Title 129, Chapter 35, Section 005.

Condition XIII.(G)(1) now reads:

- (1) Combined SO₂ emissions from biogas combustion in the flare and Boiler #5 shall be less than 40 tons per year. Combined TRS emissions from biogas combustion in the flare and Boiler #5 shall be less than 0.42 tons per year. Compliance with these limits shall be demonstrated as follows: {Title 129, Chapter 19}
 - (a) The scrubber shall be operated in accordance with the requirements under Condition XIII.(D)(1). The flare and Boiler #5 shall be operated in accordance with the requirements under Condition XIII.(D)(2).
 - (b) Combined TRS quantities to the flare and Boiler #5 shall be less than an average of 4.85 lb/hr in any consecutive 30 day period as demonstrated with the Total Sulfur CEM required in Condition XIII.(D)(1)(c) and flow meters required in Condition XIII.(D)(1)(d).

Condition XIII.(G)(2) now reads:

- (2) Combined NO_x emissions from biogas combustion in the flare and Boiler #5 shall be less than 40 tons per year. Compliance with this limit shall be demonstrated as follows: {Title 129, Chapter 19}
 - (a) The flare and Boiler #5 shall be operated in accordance with the requirements under Condition XIII.(D)(2).
 - (b) The heating value of the biogas from Scrubber WT-C1 shall be less than an average of 83 MMBtu/hr in any consecutive 30 day period and less than an average of 41.54 MMBtu/hr in any consecutive 365 day period as demonstrated with the flow meters required in Condition XIII.(D)(1)(d) and fuel gas BTU analyzer required in Condition XIII.(D)(1)(e).
 - (c) Combined biogas flow rates to the flare and Boiler #5 shall be less than an average of 90,000 standard ft³ per hour in any consecutive 30 day

period and less than an average of 74,225 standard ft³ per hour in any consecutive 365 day period as demonstrated with the flow meters required in Condition XIII.(D)(1)(d).

Condition XIII.(G)(3) now reads:

- (3) Combined CO emissions from biogas combustion in the flare and Boiler #5 shall be less than 100 tons per year. Compliance with this limit shall be demonstrated as follows: {Title 129, Chapter 19}
 - (a) The flare and Boiler #5 shall be operated in accordance with the requirements under Condition XIII.(D)(2).
 - (b) The heating value of the biogas from Scrubber WT-C1 shall be less than an average of 83 MMBtu/hr in any consecutive 30 day period and less than an average of 41.54 MMBtu/hr in any consecutive 365 day period as demonstrated with the flow meters required in Condition XIII.(D)(1)(d) and fuel gas BTU analyzer required in Condition XIII.(D)(1)(e).

Condition XIII.(I)(4) now reads:

- (4) The TRS concentration of biogas from Scrubber WT-C1 and the biogas flow rates to the flare and Boiler #5 shall be continuously recorded. Combined TRS quantities to the flare and Boiler #5 shall be calculated within 15 days after the end of each consecutive 30 day period and the calculations shall be kept on file to show compliance with Condition XIII.(G)(1)(b). The recorded biogas flow rates shall also be used to show compliance with Condition XIII.(G)(2)(c). The source shall notify the Department in writing within 20 days after the end of any consecutive 30 day or 365 day period in which an exceedance of the limits in Condition XIII.(G)(1)(b), XIII.(G)(2)(c), or XIII.(G)(4)(b) occurs.

Condition XIII.(I)(5) now reads:

- (5) Data from the fuel gas Btu analyzer and biogas flow rates to the flare and Boiler #5 shall be continuously recorded. The average heating value of the biogas from Scrubber WT-C1 shall be calculated within 15 days after the end of each consecutive 30 day and 365 day period and the calculations shall be kept on file to show compliance with Conditions XIII.(G)(2)(b) and XIII.(G)(3)(b). The source shall notify the Department in writing within 20 days after the end of any consecutive 30 day or 365 day period in which an exceedance of the limits in Condition XIII.(G)(2)(b) or XIII.(G)(3)(b) occurs.

Pursuant to a Delegation Memorandum dated May 3, 2000, and signed by the Director, the undersigned hereby executes this document on behalf of the Director.

12/21/2004

Date

Shelley Kaderly, Air Administrator
Air Quality Division

FACT SHEET

Tyson Fresh Meats, Inc.
Highway 35, IBP Avenue
Dakota City, Dakota County, NE 68731-0515

December 21, 2004

DESCRIPTION OF THE FACILITY OR ACTIVITY:

Tyson Foods, Inc. (Tyson) operates a beef slaughterhouse, rendering plant, and tannery (SIC codes 2011, 2077, and 3111, respectively) located in Dakota City, Nebraska. This facility, which was constructed in 1964 by IBP, Inc. (IBP), has a capacity of 325 cattle per hour and 1.5 million cattle per year. In addition to beef and leather, the rendering operations also produce dried blood, inedible byproducts (crax and tallow), and edible byproducts. This plant also processes raw blood, unground crax, pork crax, and hides from other Tyson plants. A tannery was added in 1988. In 1994 and 2000, IBP added covers for the anaerobic lagoons and controls were added to the wastewater treatment plant (WWTP) to control hydrogen sulfide (H₂S) emissions. Tyson acquired IBP in September 2001. The name change to Tyson Fresh Meats, Inc. took effect on June 1, 2003.

This facility was issued a construction permit on September 28, 1995, for the replacement of six boilers with a combined fuel capacity of 151.82 MMBtu/hr (four 25.4 MMBtu/hr boilers and two 25.11 MMBtu/hr boilers) with five new boilers with a combined fuel capacity of 182.5 MMBtu/hr (five 36.5 MMBtu/hr boilers). The boilers can be fired on natural gas, propane, or No. 2 fuel oil. A revised construction permit was issued for the replacement boilers on July 8, 1999, to correct errors in previous Prevention of Significant Deteriorations (PSD) netting calculations and to limit the fuel quantities that can be combusted in the boilers in order to keep emissions below the PSD significance levels of 40 tpy for sulfur dioxide (SO₂) and nitrogen oxide (NO_x) to avoid PSD review. The July 8, 1999 construction permit corrects the maximum heat input capacity of the boilers to reflect the fuel capacity listed on the boiler label plates (37.655 million Btu/hr each for natural gas and propane, 37.940 million Btu/hr each for fuel oil).

This facility was issued a PSD construction permit on July 2, 2003, for the modifications that were done in 1994 and 2000. The primary objective of the July 2, 2003, construction permit is to retroactively address PSD requirements for these modifications. The July 2, 2003 permit for the WWTP requires the installation of a packed bed scrubber and flare to control TRS emissions from the covered lagoons.

In September 2003, Tyson submitted an application for modification of the July 8, 1999 construction permit to allow biofuels to be combusted in all five existing boilers. Tyson proposed to incorporate the use of biofuels (tallow and yellow grease) as alternative backup fuels in addition to the permitted natural gas, fuel oil and propane. In addition, to allow maximum operational flexibility, Tyson requested that the usage limits for fuel oil and propane listed in the July 8, 1999 construction permit be replaced by emission limits for all boilers combined. The Department is currently processing the September 2003 application.

In May 2004, Tyson submitted a construction permit application requesting permission to combust the scrubbed biogas from the WWTP as fuel in the existing Boiler #5. The proposed modification involves the routing of the scrubbed biogas to Boiler #5 in addition to the existing flare. Tyson submitted the construction permit application for the use of biogas in Boiler #5 as supplemental data to the construction permit application that was submitted on September 15, 2003 relating to the use of biofuels in the boilers.

However, Tyson requested that the application for the biogas combustion project be considered separate from the application for the biofuels combustion project if the issuance of a combined construction permit for both projects would restrict Tyson's construction schedule for the biogas combustion project.

Even though Tyson submitted the applications for the biofuels combustion project and biogas combustion project within a relatively short time frame, the Department has determined that the two proposed projects are separate projects and, therefore, do not have to be aggregated for purposes of determining the applicability of Title 129, Chapters 17 and 19. This determination is based on the following:

- The biogas combustion project is an economically viable project by itself, with secured funding and established construction schedule. The construction schedule for the biofuels combustion project remains uncertain.
- The biogas combustion project involves the rerouting of an existing exhaust stream that is already being combusted at this facility. The biofuels combustion project, on the other hand, involves new fuels that have never been used at this facility.

This permitting action incorporates appropriate amendments to the July 8, 1999, and July 2, 2003, construction permits to allow Tyson to combust biogas as fuel in Boiler #5.

TYPE AND QUANTITY OF AIR CONTAMINANT EMISSIONS ANTICIPATED:

Emissions from this facility occur as a result of fuel/biogas combustion, rendering cookers and dryers, and other miscellaneous operations. Combustion of fuel/biogas generate emissions of several air pollutants, including NO_x, nitrogen dioxide (NO₂), CO, sulfur oxides (SO_x), sulfur dioxide (SO₂), total reduced sulfur (TRS) expressed as H₂S, total particulate matter (PM), particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (PM₁₀), volatile organic compounds (VOCs), and hazardous air pollutants (HAPs).

Boiler #5:

Boiler #5 is rated at 37.655 million Btu/hr for natural gas and propane, and 37.940 million Btu/hr for No. 2 fuel oil.

Emissions from combustion of natural gas, propane and No. 2 fuel oil were calculated using emission factors from AP-42 Section 1.4 (7/98) for natural gas, AP-42 Section 1.5 (10/96) and the emission factor for condensable PM₁₀ from FIRE 6.24 (3/04) for propane, and AP-42 Section 1.3 (9/98) for No.2 fuel oil. HAP emission factors are not available for combustion of propane. HAP emissions from propane combustion were assumed to be the same as HAP emissions from natural gas combustion on an lb/MMBtu basis.

Tyson did not provide actual emissions from Boiler #5; however, actual emissions were provided in the application for all 5 boilers combined. Detailed emission calculations for actual emissions from all 5 boilers for 2001 and 2002 are provided in Table A1 of Appendix A. Actual emissions from the existing boilers were calculated using the following assumptions:

- Actual fuel usage rates of natural gas, No.2 fuel oil and propane for 2001 and 2002.
- Actual sulfur content of No. 2 fuel oil of 0.05% by weight based on fuel supplier's certifications.
- Maximum sulfur content of propane of 15 gr/100 scf.

- Emission factors for NO_x and CO derived from the results of stack testing performed on March 23-25, 1999. The emission factors were based on the average of the test results for high-fire and low-fire.
- Other emission factors from AP-42 for natural gas combustion (Section 1.4, 7/98), No. 2 fuel oil combustion (Section 1.3, 9/98), and propane combustion (Section 1.5, 10/96), except emission factor for PM/PM₁₀ condensable from propane combustion is from FIRE 6.24 (3/04).
- Largest HAP for natural gas and No. 2 fuel oil combustion is hexane and formaldehyde, respectively. There are no HAP emission factors for propane; assume the same HAP emission factors (in lb/MMBtu) as for natural gas.
- Heating values of natural gas, No. 2 fuel oil and propane of 1000 Btu/scf, 140,000 Btu/gal and 91,500 Btu/gal, respectively.

Detailed emission calculations for the existing potential emissions from Boiler #5 are provided in Table A2 of Appendix A. The July 8, 1999 construction permit limits the combined usage of propane and No. 2 fuel oil from all boilers. Boiler #5 is capable of combusting the combined usage of propane and No. 2 fuel oil limited by the July 8, 1999 construction permit. Therefore, the potential emissions from Boiler #5 were calculated assuming all of the allowable propane and No.2 fuel oil would be combusted in Boiler #5. The existing potential emissions from Boiler #5 were calculated using the following assumptions:

- Fuel usage limitations specified in the July 8, 1999 construction permit for No. 2 fuel oil (1,075,000 gal/yr) and propane (1,100,000 gal/yr).
- Sulfur content limit for No. 2 fuel oil specified in the July 8, 1999 construction permit (0.5% by weight).
- Maximum sulfur content of propane of 15 gr/100 scf.
- NO_x emission factor for natural gas and propane provided by the manufacturer of the low NO_x burners.
- CO emission factor for fuel oil from stack testing performed on March 23-25, 1999 since it is higher than AP-42 factor.
- Other emission factors from AP-42 for natural gas combustion (Section 1.4, 7/98), No. 2 fuel oil combustion (Section 1.3, 9/98), and propane combustion (Section 1.5, 10/96), except emission factor for PM/PM₁₀ condensable from propane combustion is from FIRE 6.24 (3/04).
- Largest HAP for natural gas and No. 2 fuel oil combustion is hexane and formaldehyde, respectively. There are no HAP emission factors for propane; assume the same HAP emission factors (in lb/MMBtu) as for natural gas.
- Heating values of natural gas, No. 2 fuel oil and propane of 1000 Btu/scf, 140,000 Btu/gal and 91,500 Btu/gal, respectively.

Tyson proposed to use scrubbed biogas from the WWTP as fuel for Boiler #5. At any given time, only one of the fuels will be combusted in Boiler #5. The system will be instrumented such that all of the biogas will be used as fuel in Boiler #5; biogas will be used as fuel and flared simultaneously if demands and volumes required; or biogas will be flared as is the current practice. With the use of biogas as fuel in Boiler #5, an equivalent amount of natural gas usage will be eliminated. Consequently, actual emissions will most likely decrease as a result of the proposed project.

Emissions from combustion of biogas in Boiler #5 were calculated using the methodology provided in the fact sheet for the July 2, 2003, construction permit. Emissions of SO₂ from combustion of biogas will be generated primarily from the oxidation of TRS (expressed as H₂S) in the biogas. Detailed emission calculations for emissions from combustion of biogas in Boiler #5 are provided in Table A3 of Appendix A. Emissions from combustion of biogas in Boiler #5 were calculated based the following assumptions:

- Biogas is available as fuel for the maximum capacity of Boiler #5 (37.655 MMBtu/hr)
- Conversion of TRS to SO₂ in the boiler is expected to be practically 100% (better combustion efficiency is expected from a boiler relative to a flare due to the more controlled environment of the boiler).
- SO₂ emission factor was calculated based on the existing limit of TRS to the flare in the July 2, 2003, construction permit and a maximum biogas flow rate of 74,225 scf/hr as follows:

$$(4.85 \text{ lb/hr}) \times (64/34) / (74,225 \text{ scf/hr}) = 123.00 \text{ lb/MMscf}$$
- NO_x emission factor was calculated based on a biogas heating value of 560 Btu/scf, a NH₃ content of 712 ppmv, and a thermal NO_x emission factor from manufacturer for natural gas of 35 lb/MMscf as follows:

$$[35 \times (560/1000)] + [(712 \text{ ppm}) \times (\text{lbmole}/385 \text{ scf}) \times (46 \text{ lb/lbmole})] = 104.67 \text{ lb/MMscf}$$

Based on data from limited testing conducted in 2001 at Tyson's Dakota City facility, the actual NH₃ content in the biogas was shown to be significantly less (3.08 ppmv). In lieu of conducting additional testing and/or periodic monitoring to substantiate the use of a lower value for the NH₃ content of biogas, Tyson requested that the potential emissions from the combustion of biogas be calculated using the more conservative NH₃ content (712 ppmv) that was used as the basis for the July 2, 2003, construction permit.

- Emission factors for other pollutants were assumed to be the same as AP-42 emission factors for natural gas combustion (Section 1.4, 7/98).

Detailed emissions calculations for worst-case potential emissions from combustion of natural gas, propane, No. 2 fuel oil and biogas in Boiler #5 based on the exiting sulfur content limit for fuel oil as specified in the July 8, 1999 construction permit are provided in Table A4 of Appendix A.

Tyson agreed to accept a lower permit limitation on the sulfur content of No. 2 fuel oil of 0.25% by weight in order to limit the increase in SO₂ emissions (actual to potential) due to the proposed modification to combust biogas in Boiler #5 to below the PSD major modification threshold of 40 tpy. Detailed emissions calculations of the new potential emissions from Boiler #5 based on the lower sulfur content limit are provided in Table A5 of Appendix A.

Table 1 summarizes the existing and post-modification emissions from Boiler #5.

Table 1: Summary of Emissions from Boiler #5

Pollutant	Existing Potential Emissions from Boiler #5 (tpy)	Potential Emissions from Boiler #5 with Biogas Combustion and High Sulfur Fuel Oil (tpy)	Potential Emissions from Boiler #5 with Biogas Combustion and Low Sulfur Fuel Oil (tpy)	Actual Emissions from All Boilers (tpy)	Increase in Emissions from Boiler #5 (Actual to Potential Low Sulfur) (tpy)

PM	2.68	2.68	2.68	2.90	<25
PM ₁₀	2.14	2.14	2.14	2.89	<15
SO _x	39.55	58.53	39.18	0.29	<40
NO _x	14.86	30.83	30.83	10.90	<40
CO	0.89	0.89	0.89	2.08	<100
VOC	13.58	13.58	13.58	0.73	<40
Largest Single HAP (hexane)	0.29	0.29	0.29	0.68	<2.5 ^a
Total HAPs	0.31	0.31	0.31	0.71	<10 ^a

^a Potential to potential.

Flare

Because Tyson would like to retain the option to combust biogas only in the flare, if necessary, the potential emissions from the flare remain the same as before. Actual emissions from the flare may decrease if biogas is combusted in Boiler #5. Since the flare is not being modified as a result of the proposed project and there are no increases in emissions from the flare, emissions from the flare are not considered in determining the applicability of Chapters 17 and 19.

APPLICABLE REQUIREMENTS AND VARIANCES OR ALTERNATIVES TO REQUIRED STANDARDS:

PSD

This facility is subject to the 250-tpy PSD major source threshold because the facility is not one of the 28 source categories to which the 100-tpy threshold applies. Fugitive emissions are not included for purposes of determining the applicability of the PSD regulations in Title 129, Chapter 19.

This facility is currently a major PSD source. As shown in Table 1, the increase in emissions (actual to potential) from Boiler #5 are less than the major modification thresholds specified in Title 129, Chapter 19 (e.g., 40 tpy of SO_x) if the sulfur content of fuel oil is limited by the permit to 0.25% by weight. Consequently, the proposed modification to combust biogas in Boiler #5 is not subject to the PSD requirements of Title 129, Chapter 19.

Title 129, Chapter 17

As shown in Table 1, the net increase in potential emissions from Boiler #5 are less than the applicability thresholds specified in Title 129, Chapter 17 (e.g., <40 tpy of SO_x). However, a construction permit is required for the proposed modification to combust biogas in Boiler #5 in order to limit the increase in emissions (actual to potential) of SO_x from Boiler #5 for PSD avoidance purposes.

Other Regulations of Title 129

The applicability of other regulations in Title 129 will not be changed as a result of the proposed modifications.

Construction Permit Amendment Without Public Notice

Modification of any construction permit without public review has to meet the following conditions from Title 129, Chapter 17, Section 014.

014.01A No emission limit in the original construction permit is exceeded.

No emission limit in the original construction permits issued July 8, 1999, and July 2, 2003, is exceeded as the result of the proposed combustion of biogas in Boiler #5. The sulfur content limit for No. 2 fuel oil specified in the July 8, 1999, construction permit would be made more stringent (e.g., lowered from 0.5% to 0.25% by weight) as a result of this construction permit amendment.

014.01B No applicable requirement included in an operating permit to which the source is subject is violated.

The existing Class I operating permit for this facility restricts the type of fuels combusted in the boilers to natural gas, propane and No. 2 fuel oil and requires biogas to be combusted in the flare. However, these restrictions were incorporated in the Class I operating permit solely because they are conditions of the original construction permits issued July 8, 1999, and July 2, 2003. As the original construction permits are being amended by this permitting action, such requirements would no longer be applicable to this facility upon issuance of this construction permit amendment. Consequently, the Department believes that the requirement of Section 014.01B is being met.

014.01C No emissions limit, equipment or operational standard applicable to the source will be exceeded.

While the restriction in the types of fuels combusted in Boiler #5 in the original construction permit issued July 8, 1999, is being amended to allow combustion of biogas in Boiler #5, a corresponding requirement in the original construction permit issued July 2, 2003, is being amended to require the biogas to be controlled by the flare and/or Boiler #5. The combined changes to the fuel and control requirements do not cause exceedance of any emission limits in the original construction permits, nor do they result in any overall relaxation of the operational standards that were imposed by the original construction permits for purposes of limiting emission or ensuring compliance with applicable regulator requirements of Title 129. Consequently, the Department believes that the requirement of Section 014.01C is being met.

014.01D No emissions limit, equipment or operation standard assumed to avoid a classification that would render the source subject to an otherwise applicable requirement will be exceeded.

This construction permit amendment contains limit for the sulfur content of No. 2 fuel oil that is more stringent than the limit specified in the original construction permit issued July 8, 1999. Consequently, this facility will not be subject to any additional regulatory requirements as a result of this construction permit amendment.

014.01E The nature of the constructed facility will be consistent with that described in the original Public notice materials.

Because the proposed combustion of biogas in Boiler #5 does not involve addition of any new emission sources, nor does it cause exceedance of any emission limits in the original construction permit, the Department believes that the nature of the constructed facility remains consistent with what were described in the original public notices for the construction permits issued July 8, 1999, and July 2, 2003.

In accordance with the provisions of Chapter 17, Section 014, the proposed modification is being processed without additional public review.

Proposed changes to the specific permit requirements under Condition XIII. of the July 8, 1999, construction permit are discussed as follows:

Condition XIII.(B) of the July 8, 1999, construction permit limits the fuels that may be fired in the five boilers to natural gas, propane and No. 2 fuel oil as the emissions are calculated based on these fuel types. This condition has been revised to allow combustion of biogas in Boiler #5 in addition to natural gas, propane and No. 2 fuel oil. There are no quantity limits for natural gas and biogas.

Condition XIII.(C) of the July 8, 1999, construction permit requires the source to install a flow meter for natural gas and propane and a flow meter for No. 2 fuel oil on the fuel supply lines for each boiler unless EPA Region VII approves an alternative approach for demonstrating compliance with condition XIII(G)(4). This requirement is based on 40 CFR 60.48c(g), which states that, "The owner of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day." 40 CFR 60.2 defines "affected facility" as "any apparatus to which a standard is applicable." Several applicability determinations were found on EPA's applicability determination index (ADI), which approve a single gas flow meter for multiple boilers if the gas usage can be apportioned among the individual boilers by using a parameter such as steam production. This condition specifies one flow meter for both natural gas and propane for each boiler based on a May 6, 1999 letter from IBP, which states that the existing meters are suitable for both natural gas and propane and that both fuels are delivered through the same fuel lines. A multiplier is used to correct the meter readings for propane. This condition has been revised to add the requirement for the source to install a flow meter on the biogas supply line to Boiler #5.

Condition XIII.(G)(1) of the July 8, 1999, construction permit contains the requirement of NSPS Subpart Dc that the No. 2 fuel oil combusted must comply with ASTM D396-78 and limits fuel sulfur content to 0.5 weight percent. This condition has been revised to lower the sulfur content of No. 2 fuel oil combusted in the boilers to 0.25 weight percent to ensure that the proposed modification does not trigger PSD. The new sulfur content limit is more stringent than the corresponding requirement of NSPS Subpart Dc.

Condition XIII.(G)(2) of the July 8, 1999, construction permit specifies fuel supplier certification requirements of NSPS Subpart Dc to demonstrate compliance with the sulfur content limit for No. 2 fuel oil. This condition has been revised to add the requirement that the fuel supplier certification must include the sulfur content of the No. 2 fuel oil to demonstrate compliance with the lower sulfur content limit of Condition XIII.(G)(1).

Proposed changes to the specific permit requirements under Condition XIII. of the July 2, 2003, construction permit are discussed as follows:

Condition XIII.(B) of the July 2, 2003, construction permit requires the three new anaerobic lagoons (#9, #10 and #11) to be equipped with sealed covers connected to the packed bed scrubber and flare required in Condition XIII.(D). This condition has been revised to allow the routing of the biogas to Boiler #5 in addition to the flare.

Condition XIII.(D) of the July 2, 2003, construction permit requires a packed bed scrubber, identified as Scrubber WT-C1, and flare to control emissions from the two existing (#7 and #8) and three new covered lagoons (#9, #10 and #11). Biogas is required to be stored under the covers during scrubber maintenance. This condition has been revised to allow combustion of biogas in Boiler #5 in addition to the flare.

A continuous emission monitor (CEM) is required to measure the TRS content of the biogas stream exiting Scrubber WT-C1 that will be subsequently combusted in the flare and/or Boiler #5. The Department approved the use of a Total Sulfur CEM as a conservatively high measure of TRS. Although no new source performance standards (NSPS) are applicable, 40 CFR 60 provides suitable requirements for calibration, operation, and maintenance requirements. In addition, flow meters are required to measure the biogas flow rates to the flare and Boiler #5. Tyson proposed to use 2 separate flow meters to measure the biogas flow rate to the flare and Boiler #5. The TRS content and biogas flow rate data are used to demonstrate compliance with the TRS and SO₂ limits in Condition XIII.(G)(1).

This condition also requires a fuel gas Btu analyzer to determine the heat value of the biogas exiting Scrubber WT-C1. The source is required to submit for approval a calibration and maintenance protocol for the Btu analyzer. The data is used to demonstrate compliance with the NO_x and CO limits in Condition XIII.(G)(2).

Condition XIII.(D)(2)(d) states that the source is required to notify the Department in writing of any malfunction of the flare causing excess emissions for more than 1 hour within 48 hours of the malfunction in accordance with Title 129, Chapter 35, Section 005. Section 005.01 of Chapter 35 states that the notification is not required if a certified continuous emissions monitor (CEM) is in operation throughout the period of malfunction. In this case, the notification would be required because the Total Sulfur CEM is located prior to the flare and does not measure emissions coming from the flare.

A requirement to prepare a preventative maintenance plan for the Total Sulfur CEM is included in this condition after large discrepancies caused by a clogged flow probe were noted during the initial stack test.

Condition XIII.(G)(1) of the July 2, 2003, construction permit limits emissions from the flare to less than 40 tpy of SO₂, the PSD significant net emission increase threshold, as required by Title 129, Chapter 19, and limits emissions of TRS to 0.42 tpy. This condition has been revised to allow combustion of biogas in Boiler #5 in addition to the flare. The emission limits apply to the combined emissions from biogas combustion in the flare and Boiler #5.

Compliance is demonstrated by operating the scrubber, flare and Boiler #5 per manufacturer's specification and limiting TRS quantities to the flare and Boiler #5 to a consecutive 30 day average of less than 4.85 lb/hr using a Total Sulfur CEM and the flow meters. The emission limits are calculated below:

Molecular Weight (MW) of H₂S = 34 lb/lb-mol; MW of SO₂ = 64 lb/lb-mol
(assuming that all TRS is H₂S)

4.85 lb H₂S/hr × 64/34 × 8760 hours/yr × ton/2000 lb = 40 tpy SO₂
(assuming worst-case 100% conversion of H₂S to SO₂)

4.85 lb H₂S/hr × 0.02 × 8760 hours/yr × ton/2000 lb = 0.42 tpy H₂S
(assuming worst-case 98% conversion of H₂S to SO₂)

The source requested the lb/hr limit be changed to an annual limit in a March 6, 2000 letter. Although the PSD significance level for SO₂ is an annual quantity of 40 tons, EPA's February 24, 1992 memorandum Use of Long Term Rolling Averages to Limit Potential to Emit states that emission limits exceeding one month are only allowed for sources with substantial and unpredictable annual variations in production. The Department used a consecutive 30 day time period because this source does not have substantial and unpredictable annual variations in production.

Condition XIII.(G)(2) of the July 2, 2003 construction permit limits emissions from the flare to less than 40 tons of NO_x per year, the PSD significant net emission increase threshold, as required by Title 129, Chapter 19. This condition has been revised to allow the combustion of biogas in Boiler #5 in addition to the flare. The emission limit applies to the combined emissions from biogas combustion in the flare and Boiler #5.

Thermal NO_x is formed by reactions between nitrogen and oxygen in the combustion air. Condition XIII.(G)(2)(b) limits thermal NO_x formation by limiting the heating value of the biogas combusted in the flare and Boiler #5 to a 365 consecutive day average of 41.54 MMBtu/hr. The source used an emission factor of 0.0641 lb/MMBtu from the Texas Commission on Environmental Quality (TCEQ). The Department used the AP-42 Chapter 13.5 emission factor of 0.068 lb/MMBtu to be conservative. The potential emissions from thermal NO_x formation with these limits is estimated below:

41.54 MMBtu/hr × 0.068 lb NO_x/MMBtu × 8760 hr/yr × ton/2000 lb = 12.37 tpy NO_x

Additionally, fuel NO_x results from conversion of ammonia (NH₃) to NO_x. Source testing of the first two covered lagoons has shown the NH₃ concentration in the biogas to be 712 ppm_v. The potential emissions for NO_x formation from combustion of NH₃ at this concentration with these limits is estimated below:

$$\rho = \frac{m}{V} = \frac{P_{GAS} \times MW}{RT} = \frac{P_{TOTAL} \times ppm_v \times MW}{RT}$$

where:

ρ = vapor density of NH₃ in biogas (lb/ft³)

m = mass of NH₃ (lb)

V = volume of biogas (ft^3)
 P_{GAS} = partial pressure of NH_3 (psi)
 MW = molecular weight of NH_3 (lb/lb-mol)
 R = universal gas constant (10.73 psi ft^3 /lb-mol °R)
 T = temperature of biogas (°R)
 P_{TOTAL} = atmospheric pressure (psi)
 ppm_v = concentration of NH_3 in biogas (mol/ 10^6 mol)

$$\rho = \frac{14.7 \text{ psi} \times \left(\frac{712 \text{ mol } NH_3}{10^6 \text{ mol biogas}} \right) \times \left(\frac{17 \text{ lb } NH_3}{\text{lb mol } NH_3} \right)}{\left(\frac{10.73 \text{ psi } ft^3}{\text{lb mol } R} \right) \times 528 \text{ R}} = \frac{3.14 \times 10^{-5} \text{ lb } NH_3}{ft^3 \text{ biogas}}$$

$$\left(\frac{74,225 \text{ scf biogas}}{\text{hour}} \right) \times \left(\frac{3.14 \times 10^{-5} \text{ lb } NH_3}{ft^3 \text{ biogas}} \right) \times \left(\frac{46 \text{ lb } NO_2}{17 \text{ lb } NH_3} \right) = \frac{6.308 \text{ lb } NO_2}{\text{hour}}$$

$$\left(\frac{6.308 \text{ lb } NO_2}{\text{hour}} \right) \times \left(\frac{8760 \text{ hours}}{\text{year}} \right) \times \left(\frac{\text{ton}}{2000 \text{ lb}} \right) = \frac{27.63 \text{ tons } NO_2}{\text{year}}$$

The combined potential emissions of NO_x from the flare and Boiler #5 with the limits in this condition is estimated below:

$$12.37 \text{ tpy (thermal } NO_x) + 27.63 \text{ tpy (fuel } NO_x) = 40 \text{ tons } NO_x/\text{year}$$

Condition XIII.(G)(3) of the July 2, 2003 construction permit limits emissions from the flare to less than 100 tpy of CO, the PSD significant net emission increase threshold, as required by Title 129, Chapter 19. This condition has been revised to allow the combustion of biogas in Boiler #5 in addition to the flare. The emission limit applies to the combined emissions from biogas combustion in the flare and Boiler #5.

Compliance is demonstrated by operating the flare and Boiler #5 according to manufacturer's specifications and limiting the heating value of the biogas exiting Scrubber WT-C1 a 365 consecutive day average of 41.54 MMBtu/hr using a fuel gas Btu analyzer and the flow meters. The source used emission factors from the TCEQ. The TCEQ emission factor is conservative because the AP-42 Chapter 13.5 emission factor is 0.37 lb/MMBtu. The potential emissions with these limits is estimated below:

$$41.54 \text{ MMBtu/hr} \times 0.5496 \text{ lb CO/MMBtu} \times 8760 \text{ hr/yr} \times \text{ton}/2000 \text{ lb} = 100 \text{ tpy CO}$$

Condition XIII.(I)(4) of the July 2, 2003 construction permit requires recordkeeping of the biogas flow rate and TRS quantities to the flare. This condition has been revised to add similar recordkeeping requirements for Boiler #5.

Condition XIII.(I)(5) of the July 2, 2003 construction permit requires recordkeeping of data from the fuel gas Btu analyzer and the biogas flow rate to the flare. This condition has been revised to add biogas flow rate recordkeeping requirement for Boiler #5.

STATUTORY OR REGULATORY PROVISIONS ON WHICH PERMIT REQUIREMENTS ARE BASED:

Applicable regulations: Title 129 - Nebraska Air Quality Regulations as amended February 7, 2004.

Attachment A
Emission Calculations

Table A1: Actual Emissions from All Boilers

Emission Factors *			
	Natural Gas (lb/MMscf)	No. 2 Fuel Oil (lb/Mgal)	Propane (lb/Mgal)
PM	7.45	3.3	1.106
PM10	7.45	2.3	1.106
SOx **	0.59	7.2	1.5
NOx ***	28.00	12.46	4.30
VOC	5.39	0.2	0.3
CO***	1.73	7.76	0
Largest HAP	1.76	0.061	1.65E-04
Total HAP	1.85	0.078	1.73E-04

* Except where noted, emission factors are from AP-42: natural gas - Section 1.4 (7/98); #2 fuel oil - Section 1.3 (9/98); propane - Section 1.5 (10/96) except emission factor for PM/PM10 condensable is from FIRE 6.24 (3/04). Largest HAP for natural gas and fuel oil are hexane and formaldehyde, respectively.

There are no HAP emission factors for propane; assume the same HAP emission factors (in lb/MMBtu) as for natural gas.

** The SOx emission factor for No. 2 fuel oil was calculated using the maximum actual sulfur content of 0.05%.

The SOx emission factor for propane was calculated using a maximum sulfur content of 15 gr/100 ft³.

*** The NOx and CO emission factors are from the results of emission testing performed on March 23-25, 1999 (average of high fire and low fire values).

Heating values of natural gas, No. 2 fuel oil, and propane are 1000 Btu/scf, 140,000 Btu/gal, and 91,500 Btu/gal, respectively.

Emissions from Combustion of Natural Gas

	Fuel Consumption (MMscf/yr)		Emission Factor (lb/MMscf)	Emission (ton/year)	
	2001*	2002**		2001	2002
PM	776.55	762.91	7.45	2.89	2.84
PM10	776.55	762.91	7.45	2.89	2.84
SOx	776.55	762.91	0.59	0.23	0.22
NOx	776.55	762.91	28.00	10.87	10.68
VOC	776.55	762.91	5.39	2.09	2.06
CO	776.55	762.91	1.73	0.67	0.66
Largest HAP	776.55	762.91	1.76	0.69	0.67
Total HAPs	776.55	762.91	1.85	0.72	0.71

* Based on reported natural gas usage of 776.55 MMscf/yr for all boilers in 2001.

** Based on reported natural gas usage of 762.911 MMscf/yr for all boilers in 2002.

Emissions from Combustion of No. 2 Fuel Oil

	Fuel Consumption (Mgal/yr)		Emission Factor (lb/Mgal)	Emission (ton/year)	
	2001*	2002**		2001	2002
PM	31.59	1.46	3.30	0.05	0.00
PM10	31.59	1.46	2.30	0.04	0.00
SOx	31.59	1.46	7.20	0.11	0.01
NOx	31.59	1.46	12.46	0.20	0.01
VOC	31.59	1.46	0.20	0.00	0.00
CO	31.59	1.46	7.76	0.12	0.01
Largest HAP	31.59	1.46	0.06	0.00	0.00
Total HAPs	31.59	1.46	0.08	0.00	0.00

* Based on reported No. 2 fuel oil usage of 31,587 gal/yr for all boilers in 2001.

** Based on reported No. 2 fuel oil usage of 1,458 gal/yr for all boilers in 2002.

Emissions from Combustion of Propane

	Fuel Consumption (Mgal/yr)		Emission Factor (lb/Mgal)	Emission (ton/year)	
	2001*	2002**		2001	2002
PM	2.07	20.42	1.11	0.00	0.01
PM10	2.07	20.42	1.11	0.00	0.01
SOx	2.07	20.42	1.50	0.00	0.02
NOx	2.07	20.42	4.30	0.00	0.04
VOC	2.07	20.42	0.30	0.00	0.00
CO	2.07	20.42	0.00	0.00	0.00
Largest HAP	2.07	20.42	0.00	0.00	0.00
Total HAPs	2.07	20.42	0.00	0.00	0.00

* Based on reported propane usage of 2,073 gal/yr for all boilers in 2001.

** Based on reported propane usage of 20,420 gal/yr for all boilers in 2002.

Actual Emissions from Boilers

	2001 Actual Emissions (ton/year)	2002 Actual Emissions (ton/year)	2-Year Average Actual Emissions (ton/year)
PM	2.95	2.86	2.90
PM10	2.93	2.86	2.89
SOx	0.34	0.24	0.29
NOx	11.07	10.73	10.90
VOC	2.10	2.06	2.08
CO	0.79	0.67	0.73
Largest HAP*	0.69	0.67	0.68
Total HAPs	0.72	0.71	0.71

* Largest HAP is hexane from natural gas combustion.

Table A2: Existing PTE from Boiler #5

Emission Factors *

	Natural Gas		No. 2 Fuel Oil		Propane	
	(lb/10 ³ scf)	(lb/scf)	(lb/10 ³ gal)	(lb/gal)	(lb/10 ³ gal)	(lb/gal)
PM	7.45	7.45E-06	3.3	3.30E-03	1.106	1.11E-03
PM10	7.45	7.45E-06	2.3	2.30E-03	1.106	1.11E-03
SOx **	0.59	5.88E-07	72	7.20E-02	1.5	1.50E-03
NOx ***	35	3.50E-05	20	2.00E-02	4.94	4.94E-03
VOC	5.39	5.39E-06	0.2	2.00E-04	0.3	3.00E-04
CO****	82.35	8.24E-05	7.76	7.76E-03	3.2	3.20E-03
Largest HAP	1.76	1.76E-06	0.061	6.10E-05	1.65E-04	1.65E-07
Total HAPs	1.85	1.85E-06	0.078	7.80E-05	1.73E-04	1.73E-07

* Except where noted, emission factors are from AP-42: natural gas - Section 1.4 (7/98); #2 fuel oil - Section 1.3 (9/98); propane - Section 1.5 (10/96) except emission factor for PM/PM10 condensable is from FIRE 6.24 (3/04). Largest HAP for natural gas and fuel oil are hexane and formaldehyde, respectively.

There are no HAP emission factors for propane; assume the same HAP emission factors (in lb/MMBtu) as for natural gas.

** The SOx emission factor for No. 2 fuel oil was calculated using the maximum sulfur content of 0.5%.

The SOx emission factor for propane was calculated using a maximum sulfur content of 15 gr/100 ft³.

*** Emission factor for natural gas and propane provided by the manufacturer of the low NOx burners.

**** The CO emission factor for fuel oil is based emission testing performed on March 23-25, 1999 since it is higher than AP-42 factor.

Emissions from Natural Gas Combustion

	Fuel Consumption			Emission Factor (lb/scf)	Emissions			
	(scf/year)*	(scf/year)**	(scf/year)***		(ton/year) *	(ton/year) **	(ton/year) ***	(ton/year) ****
PM	3.30E+08	2.29E+08	1.81E+08	7.45E-06	1.23	0.85	0.67	0.30
PM10	3.30E+08	2.29E+08	1.81E+08	7.98E+07	7.45E-06	1.23	0.85	0.30
SOx	3.30E+08	2.29E+08	1.81E+08	7.98E+07	5.88E-07	0.10	0.07	0.02
NOx	3.30E+08	2.29E+08	1.81E+08	7.98E+07	3.50E-05	5.77	4.01	3.16
VOC	3.30E+08	2.29E+08	1.81E+08	7.98E+07	5.39E-06	0.89	0.62	0.49
CO	3.30E+08	2.29E+08	1.81E+08	7.98E+07	8.24E-05	13.58	9.43	7.43
Largest HAP	3.30E+08	2.29E+08	1.81E+08	7.98E+07	1.76E-06	0.29	0.20	0.16
Total HAPs	3.30E+08	2.29E+08	1.81E+08	7.98E+07	1.85E-06	0.31	0.21	0.17

* Based on 8760 hours/year, 37.655 MMBtu/hr, and a heating value of 1000 Btu/ft³.

** Based on 6085 hours/year (8760 hours - 2675 hours of propane combustion), 37.655 MMBtu/hr, and a heating value of 1000 Btu/ft³.

*** Based on 4795 hours/year (8760 hours - 3965 hours of no. 2 fuel oil combustion), 37.655 MMBtu/hr, and a heating value of 1000 Btu/ft³.

**** Based on 2120 hours/year (8760 hours - 2675 hours of propane combustion - 3965 hours of no. 2 fuel oil combustion), 37.655 MMBtu/hr, and a heating value of 1000 Btu/ft³.

Emissions from Combustion of Propane

	Fuel Consumption (gal/year) *	Emission Factor (lb/gal)	Emissions (ton/year)
PM	1,100,000	1.11E-03	0.61
PM10	1,100,000	1.11E-03	0.61
SOx	1,100,000	1.50E-03	0.83
NOx	1,100,000	4.94E-03	2.72
VOC	1,100,000	3.00E-04	0.17
CO	1,100,000	3.20E-03	1.76
Largest HAP	1,100,000	1.65E-07	0.00
Total HAPs	1,100,000	1.73E-07	0.00

* The fuel usage limit equates to 2675 hours/year assuming 37.655 MMBtu/hr and a heating value of 91,500 Btu/gal.

Emissions from Combustion of No. 2 Fuel Oil

	Fuel Consumption (gal/year) *	Emission Factor (lb/gal)	Emissions (ton/year)
PM	1,075,000	3.30E-03	1.77
PM10	1,075,000	2.30E-03	1.24
SOx	1,075,000	7.20E-02	38.70
NOx	1,075,000	2.00E-02	10.75
VOC	1,075,000	2.00E-04	0.11
CO	1,075,000	7.76E-03	4.17
Largest HAP	1,075,000	6.10E-05	0.03
Total HAPs	1,075,000	7.80E-05	0.04

* The fuel usage limit equates to 3965 hours/year assuming 37.94 MMBtu/hr and a heating value of 140,000 Btu/gal.

Potential Emissions with Permit Limits

	natural gas (ton/year) *	natural gas and propane (ton/year) **	natural gas and no. 2 fuel oil (ton/year) ***	natural gas, propane, and no. 2 fuel oil (ton/year) ****	potential emissions [highest value] (ton/year)
PM	1.23	1.46	2.45	2.68	2.68
PM10	1.23	1.46	1.91	2.14	2.14
SOx	0.10	0.89	38.75	39.55	39.55
NOx	5.77	6.73	13.91	14.86	14.86
VOC	0.89	0.78	0.59	0.49	0.89
CO	13.58	11.19	11.61	9.22	13.58
Largest HAP	0.29	0.20	0.16	0.07	0.29
Total HAPs	0.31	0.21	0.21	0.12	0.31

* Natural gas combustion for 8760 hrs/yr.

** Natural gas combustion for 6085 hr/yr and propane combustion for 2675 hrs/yr.

*** Natural gas combustion for 4795 hr/yr and no. 2 fuel oil combustion for 3965 hrs/yr.

**** Natural gas combustion for 2120 hrs/yr, propane combustion for 2675 hrs/yr, and no. 2 fuel oil combustion for 3965 hrs/yr.

Table A3: Biogas Combustion (560 Btu/scf) in Boiler #5

Pollutant	Emission Factor (lb/MMscf)	Emission Factor Origin	Firing Rate of Boiler (MMBtu/hr)	Emission Rate (lb/hr)	Total Emissions (tons/yr)
PM ^d	4.17	AP-42	37.655	0.28	1.23
PM ₁₀ ^a	4.17	AP-42	37.655	0.28	1.23
SO _x ^b	123.00	Permit Limit	37.655	8.27	36.22
NO _x ^c	104.67	AP-42	37.655	7.04	30.83
CO ^d	46.12	AP-42	37.655	3.10	13.58
VOC ^a	3.02	AP-42	37.655	0.20	0.89
TRS	0.00	^d	37.655	0.00	0.00
Largest Single HAP ^a (hexane)	0.99	AP-42	37.655	0.066	0.29
Total HAPs ^a	1.04	AP-42	37.655	0.070	0.31

^a AP-42 emission factors taken from Tables 1.4-1 & 1.4-2 (7/98) converted to biogas with heating value of 560 Bu/scf.

^b SO₂ factor is based on existing limit of TRS to the flare in 7/2/03 construction permit and biogas flow rate of 74,225 scf/hr (4.85 lb/hr) x (64/34) / (74225 scf/hr) = 123.00 lb/MMscf

^c NO_x factor is based on biogas heating value of 560 Btu/scf, NH₃ content of 712 ppmv, and thermal NO_x factor from vendor for natural gas of 35 lb/MMscf:

$$[35*(560/1000)] + [(712 \text{ ppm}) * (\text{lbmole}/385 \text{ scf}) * (46 \text{ lb}/\text{lbmole})] = 104.67 \text{ lb}/\text{MMscf}$$

^d Conversion of TRS to SO₂ in boiler is expected to be practically 100%

Table A4: Emissions from Boiler #5 with Biogas Combustion and High Sulfur Content Limit for Fuel Oil

Emission Factors *

	Biogas		No. 2 Fuel Oil		Propane	
	(lb/10 ³ scf)	(lb/scf)	(lb/10 ³ gal)	(lb/gal)	(lb/10 ³ gal)	(lb/gal)
PM	4.17	4.17E-06	3.3	3.30E-03	1.106	1.11E-03
PM10	4.17	4.17E-06	2.3	2.30E-03	1.106	1.11E-03
SOx **	123.00	1.23E-04	72	7.20E-02	1.5	1.50E-03
NOx ***	104.67	1.05E-04	20	2.00E-02	4.94	4.94E-03
VOC	3.02	3.02E-06	0.2	2.00E-04	0.3	3.00E-04
CO****	46.12	4.61E-05	7.76	7.76E-03	3.2	3.20E-03
Largest HAP	0.99	9.88E-07	0.061	6.10E-05	1.65E-04	1.65E-07
Total HAPs	1.04	1.04E-06	0.078	7.80E-05	1.73E-04	1.73E-07

* Except where noted, emission factors are from AP-42: natural gas - Section 1.4 (7/98); #2 fuel oil - Section 1.3 (9/98); propane - Section 1.5 (10/96) except emission factor for PM/PM10 condensable is from FIRE 6.24 (3/04). Largest HAP for natural gas and fuel oil are hexane and formaldehyde, respectively.

There are no HAP emission factors for propane; assume the same HAP emission factors (in lb/MMBtu) as for natural gas.

** The SOx emission factor for No. 2 fuel oil was calculated using the maximum sulfur content of 0.5%.

The SOx emission factor for propane was calculated using a maximum sulfur content of 15 gr/100 ft³.

*** Emission factor for natural gas and propane provided by the manufacturer of the low NOx burners.

**** The CO emission factor for fuel oil is based emission testing performed on March 23-25, 1999 since it is higher than AP-42 factor.

Emissions from Biogas Gas Combustion*

	Fuel Consumption				Emission Factor (lb/scf)	Emissions			
	(scf/year)**	(scf/year)**	(scf/year)****	(scf/year)****		(ton/year)**	(ton/year)***	(ton/year)****	(ton/year)****
PM	5.89E+08	4.09E+08	3.22E+08	1.43E+08	4.17E-06	1.23	0.85	0.67	0.30
PM10	5.89E+08	4.09E+08	3.22E+08	1.43E+08	4.17E-06	1.23	0.85	0.67	0.30
SOx	5.89E+08	4.09E+08	3.22E+08	1.43E+08	1.23E-04	36.22	25.16	19.83	8.77
NOx	5.89E+08	4.09E+08	3.22E+08	1.43E+08	1.05E-04	30.83	21.41	16.87	7.46
VOC	5.89E+08	4.09E+08	3.22E+08	1.43E+08	3.02E-06	0.89	0.62	0.49	0.22
CO	5.89E+08	4.09E+08	3.22E+08	1.43E+08	4.61E-05	13.58	9.43	7.43	3.29
Largest HAP	5.89E+08	4.09E+08	3.22E+08	1.43E+08	9.88E-07	0.29	0.20	0.16	0.07
Total HAPs	5.89E+08	4.09E+08	3.22E+08	1.43E+08	1.04E-06	0.31	0.21	0.17	0.07

* Emissions from biogas combustion are equal to or greater than those from natural gas combustion; therefore, biogas combustion represents worst-case.

** Based on 8760 hours/year, 37.655 MMBtu/hr, and a heating value of 560 Btu/ft³.

*** Based on 6085 hours/year (8760 hours - 2675 hours of propane combustion), 37.655 MMBtu/hr, and a heating value of 560 Btu/ft³.

**** Based on 4795 hours/year (8760 hours - 3965 hours of no. 2 fuel oil combustion), 37.655 MMBtu/hr, and a heating value of 560 Btu/ft³.

***** Based on 2120 hours/year (8760 hours - 2675 hours of propane combustion - 3965 hours of no. 2 fuel oil combustion), 37.655 MMBtu/hr, and a heating value of 560 Btu/ft³.

Emissions from Combustion of Propane

	Fuel Consumption (gal/year) *	Emission Factor (lb/gal)	Emissions (ton/year)
PM	1,100,000	1.11E-03	0.61
PM10	1,100,000	1.11E-03	0.61
SOx	1,100,000	1.50E-03	0.83
NOx	1,100,000	4.94E-03	2.72
VOC	1,100,000	3.00E-04	0.17
CO	1,100,000	3.20E-03	1.76
Largest HAP	1,100,000	1.65E-07	0.00
Total HAPs	1,100,000	1.73E-07	0.00

* The fuel usage limit equates to 2675 hours/year assuming 37.655 MMBtu/hr and a heating value of 91,500 Btu/gal.

Emissions from Combustion of No. 2 Fuel Oil

	Fuel Consumption (gal/year) *	Emission Factor (lb/gal)	Emissions (ton/year)
PM	1,075,000	3.30E-03	1.77
PM10	1,075,000	2.30E-03	1.24
SOx	1,075,000	7.20E-02	38.70
NOx	1,075,000	2.00E-02	10.75
VOC	1,075,000	2.00E-04	0.11
CO	1,075,000	7.76E-03	4.17
Largest HAP	1,075,000	6.10E-05	0.03
Total HAPs	1,075,000	7.80E-05	0.04

* The fuel usage limit equates to 3965 hours/year assuming 37.94 MMBtu/hr and a heating value of 140,000 Btu/gal.

Potential Emissions with Permit Limits

	biogas (ton/year) *	biogas and propane (ton/year) **	biogas and no. 2 fuel oil (ton/year) ***	biogas, propane, and no. 2 fuel oil (ton/year) ****	potential emissions [highest value] (ton/year)
PM	1.23	1.46	2.45	2.68	2.68
PM10	1.23	1.46	1.91	2.14	2.14
SOx	36.22	25.99	58.53	48.29	58.53
NOx	30.83	24.13	27.62	20.93	30.83
VOC	0.89	0.78	0.59	0.49	0.89
CO	13.58	11.19	11.61	9.22	13.58
Largest HAP	0.29	0.20	0.16	0.07	0.29
Total HAPs	0.31	0.21	0.21	0.12	0.31

* Biogas combustion for 8760 hrs/yr.

** Biogas combustion for 6085 hr/yr and propane combustion for 2675 hrs/yr.

*** Biogas combustion for 4795 hr/yr and no. 2 fuel oil combustion for 3965 hrs/yr.

**** Biogas combustion for 2120 hrs/yr, propane combustion for 2675 hrs/yr, and no. 2 fuel oil combustion for 3965 hrs/yr.

Table A5: Emissions from Boiler #5 with Biogas Combustion and Low Sulfur Content Limit for Fuel Oil

Emission Factors *

	Biogas		No. 2 Fuel Oil		Propane	
	(lb/10 ³ scf)	(lb/scf)	(lb/10 ³ gal)	(lb/gal)	(lb/10 ³ gal)	(lb/gal)
PM	4.17	4.17E-06	3.3	3.30E-03	1.106	1.11E-03
PM10	4.17	4.17E-06	2.3	2.30E-03	1.106	1.11E-03
SOx **	123.00	1.23E-04	36	3.60E-02	1.5	1.50E-03
NOx ***	104.67	1.05E-04	20	2.00E-02	4.94	4.94E-03
VOC	3.02	3.02E-06	0.2	2.00E-04	0.3	3.00E-04
CO****	46.12	4.61E-05	7.76	7.76E-03	3.2	3.20E-03
Largest HAP	0.99	9.88E-07	0.061	6.10E-05	1.65E-04	1.65E-07
Total HAPs	1.04	1.04E-06	0.078	7.80E-05	1.73E-04	1.73E-07

* Except where noted, emission factors are from AP-42: natural gas - Section 1.4 (7/98); #2 fuel oil - Section 1.3 (9/98); propane - Section 1.5 (10/96) except emission factor for PM/PM10 condensable is from FIRE 6.24 (3/04). Largest HAP for natural gas and fuel oil are hexane and formaldehyde, respectively.

There are no HAP emission factors for propane; assume the same HAP emission factors (in lb/MMBtu) as for natural gas.

** The SOx emission factor for No. 2 fuel oil was calculated using the maximum sulfur content of 0.25%.

The SOx emission factor for propane was calculated using a maximum sulfur content of 15 gr/100 ft³.

*** Emission factor for natural gas and propane provided by the manufacturer of the low NOx burners.

**** The CO emission factor for fuel oil is based emission testing performed on March 23-25, 1999 since it is higher than AP-42 factor.

Emissions from Biogas Gas Combustion*

	Fuel Consumption				Emission Factor (lb/scf)	Emissions			
	(scf/year)**	(scf/year)**	(scf/year)****	(scf/year)****		(ton/year)**	(ton/year)***	(ton/year)****	(ton/year)****
PM	5.89E+08	4.09E+08	3.22E+08	1.43E+08	4.17E-06	1.23	0.85	0.67	0.30
PM10	5.89E+08	4.09E+08	3.22E+08	1.43E+08	4.17E-06	1.23	0.85	0.67	0.30
SOx	5.89E+08	4.09E+08	3.22E+08	1.43E+08	1.23E-04	36.22	25.16	19.83	8.77
NOx	5.89E+08	4.09E+08	3.22E+08	1.43E+08	1.05E-04	30.83	21.41	16.87	7.46
VOC	5.89E+08	4.09E+08	3.22E+08	1.43E+08	3.02E-06	0.89	0.62	0.49	0.22
CO	5.89E+08	4.09E+08	3.22E+08	1.43E+08	4.61E-05	13.58	9.43	7.43	3.29
Largest HAP	5.89E+08	4.09E+08	3.22E+08	1.43E+08	9.88E-07	0.29	0.20	0.16	0.07
Total HAPs	5.89E+08	4.09E+08	3.22E+08	1.43E+08	1.04E-06	0.31	0.21	0.17	0.07

* Emissions from biogas combustion are equal to or greater than those from natural gas combustion; therefore, biogas combustion represents worst-case.

** Based on 8760 hours/year, 37.655 MMBtu/hr, and a heating value of 560 Btu/ft³.

*** Based on 6085 hours/year (8760 hours - 2675 hours of propane combustion), 37.655 MMBtu/hr, and a heating value of 560 Btu/ft³.

**** Based on 4795 hours/year (8760 hours - 3965 hours of no. 2 fuel oil combustion), 37.655 MMBtu/hr, and a heating value of 560 Btu/ft³.

***** Based on 2120 hours/year (8760 hours - 2675 hours of propane combustion - 3965 hours of no. 2 fuel oil combustion), 37.655 MMBtu/hr, and a heating value of 560 Btu/ft³.

Emissions from Combustion of Propane

	Fuel Consumption (gal/year) *	Emission Factor (lb/gal)	Emissions (ton/year)
PM	1,100,000	1.11E-03	0.61
PM10	1,100,000	1.11E-03	0.61
SOx	1,100,000	1.50E-03	0.83
NOx	1,100,000	4.94E-03	2.72
VOC	1,100,000	3.00E-04	0.17
CO	1,100,000	3.20E-03	1.76
Largest HAP	1,100,000	1.65E-07	0.00
Total HAPs	1,100,000	1.73E-07	0.00

* The fuel usage limit equates to 2675 hours/year assuming 37.655 MMBtu/hr and a heating value of 91,500 Btu/gal.

Emissions from Combustion of No. 2 Fuel Oil

	Fuel Consumption (gal/year) *	Emission Factor (lb/gal)	Emissions (ton/year)
PM	1,075,000	3.30E-03	1.77
PM10	1,075,000	2.30E-03	1.24
SOx	1,075,000	3.60E-02	19.35
NOx	1,075,000	2.00E-02	10.75
VOC	1,075,000	2.00E-04	0.11
CO	1,075,000	7.76E-03	4.17
Largest HAP	1,075,000	6.10E-05	0.03
Total HAPs	1,075,000	7.80E-05	0.04

* The fuel usage limit equates to 3965 hours/year assuming 37.94 MMBtu/hr and a heating value of 140,000 Btu/gal.

Potential Emissions with Permit Limits

	biogas (ton/year) *	biogas and propane (ton/year) **	biogas and no. 2 fuel oil (ton/year) ***	biogas, propane, and no. 2 fuel oil (ton/year) ****	potential emissions [highest value] (ton/year)
PM	1.23	1.46	2.45	2.68	2.68
PM10	1.23	1.46	1.91	2.14	2.14
SOx	36.22	25.99	39.18	28.94	39.18
NOx	30.83	24.13	27.62	20.93	30.83
VOC	0.89	0.78	0.59	0.49	0.89
CO	13.58	11.19	11.61	9.22	13.58
Largest HAP	0.29	0.20	0.16	0.07	0.29
Total HAPs	0.31	0.21	0.21	0.12	0.31

* Biogas combustion for 8760 hrs/yr.

** Biogas combustion for 6085 hr/yr and propane combustion for 2675 hrs/yr.

*** Biogas combustion for 4795 hr/yr and no. 2 fuel oil combustion for 3965 hrs/yr.

**** Biogas combustion for 2120 hrs/yr, propane combustion for 2675 hrs/yr, and no. 2 fuel oil combustion for 3965 hrs/yr.