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Abengoa Bioenergy Biomass of Kansas, LLC

Prevention of Significant Deterioration Air Quality Construction Permit Modification Application Source ID No. 1890231

C - 10550

Prepared for:
KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT
Topeka, Kansas

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SECTION 1
GENERAL MODELING DISCUSSION

1.1 Current Approved Project

Abengoa Bioenergy Biomass of Kansas, LLC (ABBK) applied for and received an Air Emission Source Construction Permit for a biomass-to-ethanol and biomass-to-energy production facility dated September 16, 2011. A subsequent letter dated March 15, 2012 and associated modeling files were submitted to the Kansas Department of Health and Environment to address changes in certain source locations. After reviewing the information submitted, KDHE concurred with the conclusion presented in the March 15, 2012 letter that the changes outlined therein would not significantly impact the previously modeled results relied upon for the September 16, 2011 Air Emission Source Construction Permit.

1.2 Proposed Project Changes

Abengoa presented the best design information available at the time in the Air Emission Source Construction application and Ambient Air Quality Impact Assessment (AQIA), and this information was relied upon for the September 16, 2011 Air Emission Source Construction Permit. Continued engineering of the project and finalization of certain process areas has resulted in changes to the boiler start-up design and procedures presented in the Air Emission Source Construction application and AQIA.

The boiler will continue to utilize the natural gas-fired start-up/auxiliary burner for start-up and periodically during partial fuel source interruptions. However, the final engineering design includes the addition of four natural gas (NG)-fired generator sets (EP-20010 through EP-20040) that will be used for power production to support the boiler/steam turbine generator (STG) system (and auxiliary utility support systems, such as cooling water, instrument air, raw water treatment, biomass fuel handling, etc.) during start-up, shutdown, and malfunction (SSM) events.

Only three NG generator sets (EP-20010 through EP-20030) will be used in conjunction with boiler/STG system SSM events, in which the enzymatic hydrolysis (EH) production process is idle. As the boiler heats up and begins to produce on-spec steam for the STG, the STG will be started to produce power, and the NG generator power will be reduced gradually until the boiler/STG system is operating solely on the permitted biomass blend at the reduced 30% nominal load.

The fourth NG generator set (EP-20040) will also be used to support in conjunction with boiler/STG system SSM events when the EH production process is not idle (i.e. when production tanks are full).

1.3 Proposed Equipment Operations

After initial start-up, the ABBK facility plans to have one short planned startup/shutdown event per year for scheduled maintenance, and the maximum number of boiler/STG system short unplanned start-up/shutdown events is expected not to exceed four per year. Additionally,

ABBK plans to schedule a long boiler/STG system planned maintenance event once every two years, which coincides with EH production process planned maintenance outage. In some instances, a portion of EH production process must continue to operate (not idle) during a boiler/STG system outage, in order to avoid hydrolysate spoilage, loss of live organisms and yield loss.

During a start-up of the boiler/STG system after a short planned maintenance event or a short unplanned outage, the fourth NG generator set (EP-20040) is expected to be needed if the EH production process is not idle. However, after a long boiler/STG system planned maintenance, the fourth NG generator set (EP-20040) is not required to restart the boiler/STG system because the EH production process is expected to be idle.

During a short planned maintenance or unplanned boiler/STG system event, the three NG generator sets (EP-20010 through EP-20030) could operate up to 168 hours each to continue the EH production process until the restart of the boiler/STG system. The fourth NG generator (EP-20040) would then operate up to 12 hours to support the restart of the boiler/STG system.

During a long planned maintenance boiler/STG system event, the EH production process is idle. The three NG generator sets (EP-20010 through EP-20030) could operate up to 24 hours each to restart the boiler/STG system. The EH production process would be restarted after the boiler/STG system was supplying power and the three NG generator sets were shut down.

Natural gas will be used for boiler start-up and for operating the generator sets. The selective catalytic reduction (SCR) reheat loop will be started in the boiler prior to introducing any fuels other than natural gas. The SCR reheat loop includes a duct burner, which will be used to reach SCR reaction temperature prior to the introduction of biomass-related fuels.

The hourly emissions during boiler start-up by the four NG generator sets are less than the maximum worst-case hourly emissions presented for the boiler when operating at 500 million British thermal units per hour (MMBtu/hr). For the purpose of estimating worst-case hourly emissions, it is assumed that the four NG generator sets will operate at 100% of their rating load up to the boiler's 30% nominal load, although actual emissions will be significantly less, as it is expected that the boiler will be operating solely on the permitted biomass blend at the reduced 30% nominal load. The maximum worst-case annual potential emissions relied upon in the Air Emission Source Construction Permit will not change as the four NG generator sets will not normally be used when the boiler is operating at the reduced 30% nominal load and greater.

The four NG generator sets may also be operated for the purpose of maintenance checks and readiness testing. Maintenance checks and readiness testing of these units will be limited to 100 hours each per year during normal facility operations.

The four NG generator sets meet the 40 CFR Part 60, Subpart JJJJ, *Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines (ICE),* definition of "emergency stationary internal combustion engines". This is based on the definition's specific example of the ICE being used to produce power for critical equipment, including power supplied to portions of the facility, when the normal power source (i.e. the biomass-fired boiler) is interrupted. Because ABBK produces its own power, it will not be affected by an "emergency" loss of power from the

local utility. Rather, ABBK controls its power through generation of on-site power in the boiler/STG system and through the four NG generator sets which are limited to operating during SSM events. The four NG generator sets will not operate during normal facility operations except for maintenance checks and readiness testing.

1.4 Mechanical Completion and Equipment Operations Testing Schedule

Mechanical completion of the boiler/STG system is scheduled for August 2013. Soon after this milestone the boiler will be lit and hot checkout procedures initiated. After initial checkout has been completed, the boiler will be started and used to run the STG up to approximately 30% boiler load. The amount of boiler load is restricted by not having a place to send the steam and electricity, and the overall condensing capability of the facility without the EH production process and auxiliary utility support systems complete. Testing of the boiler/STG system is expected to occur prior to December 31, 2013. After testing is completed the boiler/STG system will be shut down and not relit until needed for testing of the EH production process and auxiliary utility support systems, such as cooling water, instrument air, raw water treatment, biomass fuel handling, etc.

Mechanical completion of the EH production process and auxiliary utility support systems is scheduled for December 2013. Checkout of the EH production process will then begin with the need for steam from the boiler/STG system. The boiler will be relit and checkout of the EH production process with steam will begin around March 2014. Again, the boiler/STG system will be limited to approximately 30% boiler load due to the limited ability of the facility to condense steam.

This startup effort is expected to go into third quarter 2014, with higher levels of boiler operation beginning in 4th quarter 2014.

Operational run time of the four NG generator sets will be minimal in 2013, and approximately 6 to 7 boiler starts (24 hours each) are anticipated in 2014. Normal operation of the facility is expected by March 2015.

1.5 Report Organization

This report has been organized such that each required PSD construction permit application modification component is provided in either a section of this report or attached as an appendix. A summary of the contents of each section and appendix of this report are provided herein. Also, additional deliverables to be provided to KDHE subsequent to this report in support of the permit application modification have also described in this section.

1.5.1 Sections

<u>Section 1.0: Facility Operations / Proposed Project Changes Description</u>

A detailed description of the proposed project changes has been prepared and is included in Section 1.0.

Section 2.0: Regulatory Applicability Analysis

Section 2.0 includes a discussion for some of the applicable and non-applicable State and Federal regulations. There are numerous administrative regulations (e.g., permit posting, fees, etc.) or other statewide regulations (e.g. open burning, odor) that apply to the proposed facility, but these are not summarized in this report.

Section 3.0: Best Available Control Technology Analysis

A detailed BACT analysis for the proposed project changes has been prepared and is included in Section 3.0.

Section 4.0: Proposed Limitations and Regulatory Interpretations

Proposed limitations and regulatory interpretations for the proposed project changes have been prepared and are included in Section 4.0.

1.5.2 Appendices

Appendix A: KDHE Air Quality Spark Ignition Emergency Generator Forms

The KDHE Air Quality Spark Ignition Emergency Generator forms have been included in Appendix A.

Appendix B: Vendor Specification Sheet

The Cummins Power Generation specification sheet dated April 2009 has been included in Appendix B.

Appendix C: Potential to Emit Calculations

Potential to emit (PTE) calculations for criteria pollutants: nitrogen oxides (NOx), sulfur oxides (SOx), carbon monoxide (CO), particulate matter ($PM/PM_{10}PM_{2.5}$), volatile organic compounds (VOCs, also called non-methane hydrocarbons, NMHC); hazardous air pollutants (HAPs); and greenhouse gases (GHGs) were estimated using a combination of vendor specification sheet, emission factors from U.S. Environmental Protection Agency's (EPA) Compilation of Air Pollutant Emission Factors, 5th Edition, Volume 1 (AP-42), EPA emissions databases, EPA protocol and guidance documents, and the California Climate Action Registry's (CCAR) General Reporting Protocol. Detailed emission calculations are presented in Appendix C. Potential emission calculations include both uncontrolled and controlled scenarios.

Appendix D: Best Available Control Technology Analysis Calculations

The BACT analysis calculations for the proposed project changes are presented in Appendix D.

1.5.3 Additional Deliverables

Air Quality Impact Assessment Supplement

An AQIA supplement will be provided as detailed in the modeling protocol submitted concurrent with this permit application modification.

SECTION 2
REGULATORY APPLICABILITY

2.1 Current Kansas Air Quality Regulations

The Kansas Air Quality Regulations (K.A.R.) that were reviewed for the purpose of this permit modification application are discussed below and summarized in Table 2-1.

Table 2-1
Receptor Spacing for Significant Impact Modeling

K.A.R.	Title	Applicability Determination
K.A.R. 28-19-300	Construction Permits and Approvals; Applicability	Applicable
K.A.R. 28-19-302	Construction Permits and Approvals; Additional Provisions; Construction Permits	Not Applicable
K.A.R. 28-19-304	Construction Permits and Approvals; Fees	Applicable
K.A.R. 28-19-350	Prevention of Significant Deterioration of Air Quality	Applicable
K.A.R. 28-19-500	Operating Permits; Applicability	Applicable
K.A.R. 28-19-650	Emissions Opacity Limits	Applicable
K.A.R. 28-19-720	New Source Performance Standards	Applicable
K.A.R. 28-19-735	National Emission Standards for Hazardous Air Pollutants	Not Applicable
K.A.R. 28-19-750	Maximum Achievable Control Technology Regulations	Not Applicable

2.1.1 5K.A.R. 28-19-300 – Construction Permits and Approvals; Applicability

A construction permit is required for this facility because the PTE of the proposed project has an uncontrolled net increase in emissions equal to or greater than the thresholds listed in K.A.R. 28-19-300(a)(1)(A) through (F) for $PM/PM_{10}/PM_{2.5}$, NOx, SOx, CO, and VOC; and because the facility is an affected source as defined in K.A.R. 28 19 200(dd)(20). The emission thresholds are summarized in Table 2-2.

Table 2-2
Construction Permit Emissions Threshold

Pollutant	Threshold
PM	25 tpy
PM_{10}	15 tpy
NOx	40 tpy
SOx	40 tpy
CO	100 tpy
VOC	40 tpy

Because the facility previously exceeded at least one of the above construction permit thresholds, the facility obtained an Air Emission Source Construction Permit dated September 16, 2011. In order to ensure there was no circumvention of the regulations, this permit modification application is being submitted for the proposed project changes.

2.1.2 K.A.R. 28-19-302 – Construction Permits and Approvals; Additional Provisions; Construction Permits

This standard allows for facilities that would otherwise be required to submit an application for the construction of a new source to request a federally enforceable operational restriction be included in the construction permit which reduces the PTE of the facility, thereby reducing the requirements the facility must meet.

The facility previously requested to limit its individual HAP emissions to not more than 9.9 tons per year and total HAP emissions to not more than 24.9 tons per year based on a 12-month rolling average. This HAP limit established the facility as a synthetic minor for the purposes of 40 CFR Part 63. The facility continues to request this limit as the proposed project changes will not increase worst-case annual HAP emissions.

2.1.3 K.A.R. 28-19-304 – Construction Permits and Approvals; Fees

The facility requests a fee determination from KDHE regarding this permit modification application that is being submitted for the proposed project changes.

2.1.4 K.A.R. 28-19-350 – Prevention of Significant Deterioration of Air Quality

The requirements of this regulation were previously determined to apply to the facility, as it met the definition in 40 CFR Part 52, Prevention of Significant Deterioration of Air Quality (40 CFR §52.21) for a major stationary source and is located in an area of the state designated as attainment or unclassified area. As discussed in Section 2.1.1, in order to ensure there was no circumvention of the regulations, this permit modification application is being submitted for the proposed project changes.

2.1.5 K.A.R. 28-19-500 – Operating Permits; Applicability

The facility is required to obtain a Class I Operating Permit for the criteria pollutants, PM/PM_{10}, NOx, SOx, and CO. The proposed project changes in this permit modification application will be incorporated into the facility's Class I Operating Permit application.

2.1.6 K.A.R. 28-19-650 – Emissions Opacity Limits

This standard limits opacity from new equipment to 20% unless the equipment is subject to other K.A.R. regulations or that are subject to more stringent New Source Performance Standards (NSPS) regulations. The four NG generator sets will be limited to 20% opacity.

2.1.7 K.A.R. 28-19-720 – New Source Performance Standards

NSPS are Federal standards (40 CRF Part 60) that Kansas has adopted by reference, with the exception of 40 CFR §§60.4, 60.9, 60.10, 60.16 and Subpart HHHH. There is one NSPS that applies to the proposed project changes. This standard is discussed in detail in Section 2.2.

2.1.8 K.A.R. 28-19-735 – National Emission Standards for Hazardous Air Pollutants

National Emission Standards for Hazardous Air Pollutants (NESHAP) regulations are Federal standards (40 CFR Part 61) that Kansas has adopted by reference, with the exception of 40 CFR §§61.04, 61.16, 61.17, and Subparts H, I and K. There are no NESHAPs in 40 CFR Part 61 that apply to the proposed project changes.

2.1.9 K.A.R. 28-19-750 – Maximum Achievable Control Technology Regulations

Maximum Achievable Control Technology (MACT) regulations are Federal NESHAP standards for Source Categories (40 CFR Part 63) that Kansas has adopted by reference, with the exception of 40 CFR §§63.12, 63.13, 63.13, 63.40 through 63.44 and subpart E.

As discussed previously, the facility is requesting to limit its individual HAP emissions to not more than 9.9 tons per year and total HAP emissions to not more than 24.9 tons per year based on a 12-month rolling average. These limits make the facility a synthetic minor source of HAPs so it will not be subject to MACT rules that apply to major sources of HAPs. There is one area source MACT that applies to the proposed project changes. This standard is discussed in detail in Section 2.2.

2.2 Federal Regulations

The four NG generator sets at the facility will be subject to 40 CFR Part 63, Subpart ZZZZ, *National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE).* ABBK is an area source of HAP emissions that is constructing 4 new RICE constructed after June 12, 2006, as defined in this subpart. For new RICE located at an area source, spark ignition engines are required to meet 40 CFR Part 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition (SI) Internal Combustion Engines (ICE). There are no further applicable requirements apply for the proposed generator sets under 40 CFR Part 63, Subpart ZZZZ.

40 CFR Part 60, Subpart JJJJ applies to owners and operators of SI ICE constructed after June 12, 2006. The definition of an "emergency stationary internal combustion engine" in § 60.4248 are as follows:

> *Emergency stationary internal combustion engine means any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (**or the normal power source, if the facility runs on its own power production**) is interrupted, or stationary ICE used to pump water in the*

case of fire or flood, etc. Stationary SI ICE used for peak shaving is not considered emergency stationary ICE. Stationary ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are not considered to be emergency engines.

Based on this definition, ABBK is proposing that the four NG generator sets be considered "emergency stationary internal combustion engines". This is based on the definition's specific example of the ICE being used to produce power for critical equipment, including power supplied to portions of the facility, when the normal power source (i.e. the biomass-fired boiler) is interrupted. Because ABBK produces its own power, it is never affected by an "emergency" from loss of power from the local utility. Rather, ABBK controls its power through generation of on-site power in the biomass-fired boiler and through the four NG generator sets which are limited to operating during SSM periods. The four NG generator sets will not operate during normal facility operations except for maintenance checks and readiness testing. The standards in 40 CFR Part 60, Subpart JJJJ are listed in Table 1 of the subpart and are based on engine size. For stationary emergency engines greater than or equal to 130 HP, the standards in grams per HP-hr are as follows:

- NOx = 2.0 g/BHP-hr
- CO = 4.0 g/BHP-hr
- VOC = 1.0 g/BHP-hr

Based on the vendor specifications for the engines to be installed, the engines' emissions are less than the standard's limits for the above pollutants.

SECTION 3
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

As described in Section 2.1.4, the proposed project changes are subject to PSD review. In no event can the application of BACT result in the emission of any pollutant that would exceed the emissions allowed by the applicable NSPS. The September 16, 2011 Air Emission Source Construction Permit BACT relied on the "top-down" process to determine BACT for the permitted sources. The same BACT procedure is presented herein.

3.1 Source Description

NG-fired SI ICEs will emit a variety of air pollutants. These pollutants are primarily NOx, SOx, CO, particulate matter ($PM/PM_{10}PM_{2.5}$), VOCs (also called NMHC), HAPs and GHGs. The proposed NG generator sets are 4-Stroke Lean Burn Engines (SCC 2-02-002-54) with a rating of 1,750 kilowatts (kW) continuous power, 1,837 kW maximum power.

3.2 Identify Available Control Options

Over recent years, and expected into the future, manufacturers of SI ICE and their suppliers have been working diligently to reduce criteria pollutant emissions by a combination of engine design and add-on controls. At this time, there are only a few commercially-available criteria pollutant reduction technologies available for NG-fired SI ICEs. There are no effective combustion controls to reduce the GHG emissions from NG-fired SI ICEs, and there are currently no available post-combustion controls. The following sections discuss the control options that have been identified and considered in determining BACT.

3.2.1 Engine and Engine-Control Design

Standard lean-burn engine design is capable of reducing NOx to less than 2.5 g/BHP-hr. Low-emission designs can reduce NOx emissions to below 1.0 g/BHP-hr. The vendor specifications for the engines to be installed indicate that the NOx emissions will be 0.84 g/BHP-hr ± 5%. Low-emission designed engines require advanced control systems to maintain combustion stability. Reductions in CO are marginal for low emission design. Reductions in VOC of about 35% are likely due to cooler engine operation. For GHGs, because the amount of GHG emissions produced depends on the amount of fuel burned, and improving engine efficiency will reduce GHG emissions.

3.2.2 Three-Way Catalyst

A Three-Way Catalyst (TWC) is the basic automotive catalytic converter that reduces NOx, CO, and VOCs. TWC is also called "non-selective catalytic reduction."

3.2.3 Selective Catalytic Reduction

SCR passes the exhaust through a catalyst bed along with an ammonia source (either ammonia or urea) to reduce the NOx to nitrogen. Some excess ammonia is necessarily emitted. SCR has

only been required under permitting when the gas-powered engine is to be located in an area suffering non-attainment with the NAAQS for ozone, and not for engines intended for emergency service.

3.2.4 Catalytic Oxidation

Catalytic Oxidation uses a noble metal catalyst to reduce both CO and VOCs by as much as 98% to 99%. As with SCR, catalytic oxidation has only been required under permitting when the gas-powered engine is to be located in an area suffering non-attainment with the NAAQS, in this case, for CO. According to U.S. EPA publication 2060-AG63, *Regulatory Impact Analysis for the Stationary Internal Combustion Engine (RICE) NESHAP – Regulatory Impact Analysis,* February, 2004, fewer than 15% of 2-stroke lean-burn engines and 3% of 4-stroke lean-burn engines have been equipped with catalytic oxidation systems.

3.2.5 Fuel Restriction

SO_2 and PM_{10} emissions are almost negligible for lean-burn gas-powered engines. There were no permit imposed SO_2 or PM_{10} reduction technologies identified to reduce emissions of these pollutants from gas-powered engines except fuel restriction to natural gas or propane. Further, for GHGs, natural gas has the lowest GHG emission rate of all fuels except biogas. Because the biogas produced at the facility is the by-product of the production process, biogas cannot be used in place of the natural gas as a fuel for the NG generator sets.

3.3 Eliminate Technically Infeasible Control Options

<u>Engine and Engine-Control Design for NOx, CO and VOC Reductions – Technically Feasible</u>

The NG generator sets that will be utilized will meet specific design emission standards that are mandated by the NSPS Subpart JJJJ regulations. The NSPS Subpart JJJJ standard is a mandatory function that ensures certain engine standards are met. It is this NSPS standard that serves as the basis for this BACT determination.

For the NG generator sets, it is technically feasible to purchase NSPS-compliant engines.

<u>TWC System for NOx, CO and VOC Reductions – Technically Infeasible</u>

TWC cannot be used on the oxygen-rich exhaust expected from a lean-burn engine. Consequently, TWC is not feasible for use on lean-burn engines.

<u>SCR for NOx Reduction – Technically Feasible</u>

SCR is technically feasible; however, research in the technology has indicated that it is relatively expensive and not required under permitting for engines intended for emergency service.

<u>Catalytic Oxidation for CO Reduction – Technically Feasible</u>

SCR is technically feasible; however, research in the technology has indicated that it is relatively expensive and not required under permitting for engines intended for emergency service.

Fuel Restriction – Technically Feasible

The inherent generator design is based on the use of natural gas. The use of natural gas results in reduced emissions for all criteria pollutants and HAPs from ICEs.

3.4 Rank Technically Feasible Control Options

Based on the above discussion and the inherent generator design, the generators' baseline emissions incorporate lean-burn engine and engine-control design for NOx, CO, VOC and GHG reductions, and fuel restriction to natural gas for reductions in all emissions over other readily-available fuels. The only technically feasible post-combustion controls are SCR for NOx reduction and catalytic oxidation for CO reduction.

3.5 Evaluate Technically Feasible Control Options

The economic feasibility for the technically feasible post-combustion controls identified was calculated using potential emissions. BACT costs were evaluated using standard engineering estimating practices presented in Section 2, *Generic Equipment and Devices,* of the EPA Air Pollution Control Cost Manual, Sixth Edition, EPA-425/B-02-001.

The steps performed for the BACT economic analysis are delineated below:

1. The total capital investment (TCI) for each technically feasible control option are estimated based on the following values provided by ABBK:

Control Technology	Estimated Control Equipment Capital Cost
SCR	$410,800 Per Unit
Catalytic Oxidation	$363,200 Per Unit

2. Annualized costs are calculated using standard engineering estimating practices presented in Section 2, *Generic Equipment and Devices,* of the EPA Air Pollution Control Cost Manual, Sixth Edition, EPA-425/B-02-001. The calculations are rounded to the nearest $100. The following calculations and assumptions are used in this section to evaluate the economic feasibility of both SCR and catalytic oxidation:

    a. Total annual costs are the sum of the annual direct and indirect costs. The total annual cost (TAC) equation used for this BACT analysis is as follows:

    TAC = Direct Costs + Indirect Costs + CRF

    Where:

    Direct costs were assumed zero for a worst-case estimate of cost. These direct costs include annual operating and overhead costs.

    Indirect costs were assumed zero for a worst-case estimate of cost. These indirect costs include administrative changes, property taxes and insurance.

    CRF = capital recovery cost factor.

b. Annual operating costs are assumed minimal and consist of minor expenses such as painting and architectural repairs, etc. These direct costs are conservatively not included in the cost analysis.

c. Overhead is not considered because it is based on the sum of operating, supervisory, and maintenance labor and material costs, which are assumed to be zero and conservatively not included in the BACT analysis.

d. Annual indirect costs are assumed to be zero and conservatively not included in the BACT analysis.

e. The capital recovery cost factor (CRF) is a function of the equipment life and the opportunity cost of the capital (i.e., interest rate). For this analysis, a 10-year equipment life and a 7% interest rate is assumed. The capital recovery factor is calculated using the following equation:

$$CRF = [\, i\,(1 + i)^n \,] / [(1 + i)^n - 1]$$

Where:

CRF = capital recovery factor

i = annual interest rate (fraction)

n = number of payment years

CRF = 0.1424

3. The annualized cost is divided by the amount of emissions controlled by each technically feasible control option to calculate the dollars per ton of pollutant removed. The calculations are rounded up to the nearest $100.

Based on the calculations presented in Appendix D using the calculation methodology detailed above, it is not economic feasibility to install either SCR or catalytic oxidization on the NG generator sets. Based on the cost evaluation, ABBK concludes that the reduction of NOx emissions that could be attained with the additional add-on SCR is not justified by the cost of the technology. Further, ABBK concludes that the reduction of CO emissions that could be attained with the additional add-on catalytic oxidizer is not justified by the cost of the technology.

3.6 Establish BACT

The proposed BACT for the four NG generator sets are low-emission engine design for lean-burn engines and fuel restriction to natural gas.

3.7 BACT Compliance

The ABBK facility will demonstrate compliance with BACT for the four NG generator sets by recording fuel usage and using the emissions factors presented in the application to determine resulting emissions. Because fuel usage can be accurately measured, and the amount of emissions can be calculated precisely based on well-established emissions factors, no other direct monitoring of emissions is proposed. The emission factors presented in the application will be relied upon to demonstrate compliance with the proposed BACT.

SECTION 4
PROPOSED LIMITATIONS AND REGULATORY INTERPRETATIONS

ABBK proposes the following limitations and regulatory interpretations:

- The four NG generator sets are emergency generators that will not operate during normal facility operations except for maintenance checks and readiness testing;
- Maintenance checks and readiness testing of these units will be limited to 100 hours each per year during normal facility operations;
- No annual hours of operation limits are proposed for the four NG generator sets, except for maintenance checks and readiness testing, based on the following:
  - The maximum worst-case hourly emissions presented in the attached potential to emit calculations demonstrate that when all four NG generator sets are operated at 100% of load in conjunction with the biomass-fired boiler operating at the reduced 30% of nominal load, the hourly emissions are less than the worst-case hourly emissions in the September 16, 2011 Air Emission Source Construction Permit.
  - The facility produces power using the boiler/STG system. If the boiler/STG system is not operational, the facility cannot operate, thus, extended periods of generator operation are not feasible as the generator sets cannot be relied upon to power the facility for any other purpose other than SSM/emergency situations.
  - There are no hour limits for similar units during emergency use.
- The four NG generator sets will be equipped with non-resettable hour-meters. Records will be maintained that specify the purpose of generators' use when operated.
- The four NG generator sets will comply with the requirements of 40 CFR Part 60, Subpart JJJJ and 40 CFR Part 63, Subpart ZZZZ, as outlined in the application forms contained in Appendix A.

APPENDIX A
KDHE AIR QUALITY SPARK IGNITION EMERGENCY GENERATOR FORMS

Kansas Department of Health and Environment – Bureau of Air
1000 SW Jackson, Suite 310, Topeka, KS 66612
Phone: (785) 296-1570 Fax: (785) 291-3953

Application for Approval

Spark Ignition Emergency Generators

This approval is suitable for spark ignition emergency generators used only for back-up power when the primary electric power is interrupted during emergency situations or for short periods to perform maintenance and operational readiness testing. The KDHE believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions.

For diesel emergency generators, use the Compression Ignition Emergency Generator Application.

Engine Data

Date of construction:	
Has the engine been modified or reconstructed? ☐ Yes, reconstructed/modified (*circle one*) If yes, date: ☒ No	
Fuel(s) burned in the engine (check all that apply): ☐ Gasoline ☒ Natural Gas ☐ LPG ☐ Other (please specify):	Engine Manufacturer: Cummins Power Generations Horsepower: 2,463 bhp Date of Manufacture: TBD
Will the engine be used for peak shaving or supply power to the electrical grid? ☐ Yes ☒ No	
Has the engine been certified to meet the applicable emission standards of 40 CFR Part 60, Subpart JJJJ? ☒ Yes ☐ No	
Will the engine be located at a facility that is a major source of HAPs? ☐ Yes ☒ No	
Will the engine be located at a residential, commercial, or institutional facility? ☐ Yes ☒ No	
Owner/Operator's identification number/name for the engine: EP-20010, Generator Set #1	

Facility Information

Company Name: Abengoa Bioenergy Biomass of Kansas, LLC	Source ID number: 1890231
Source Location	
Facility name: Abengoa Bioenergy Biomass of Kansas, LLC	
Street Address: TBD	County: Stevens County
City, State, Zip: Hugoton, KS 67951	Section, Township, Range: T33S, R37W, Sec 18
Mailing Address (if different)	
Street Address: 16150 Main Circle Drive, Suite 200	
City, State, Zip: Chesterfield, MO 63017	
Contact Information	
Name: Robert Wildgen	Telephone Number: (636) 728-4515
Email: Robert.Wildgen@bioenergy.abengoa.com	Fax Number: (636) 536-6175

I certify that the above information is true, accurate, and complete.

Signature: _____ Date: 10/15/12

Please complete the above form for each engine and fax to (785) 291-3953, or mail to the above address.

Kansas Department of Health and Environment – Bureau of Air
1000 SW Jackson, Suite 310, Topeka, KS 66612
Phone: (785) 296-1570 Fax: (785) 291-3953

Application for Approval

Spark Ignition Emergency Generators

This approval is suitable for spark ignition emergency generators used only for back-up power when the primary electric power is interrupted during emergency situations or for short periods to perform maintenance and operational readiness testing. The KDHE believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions.

For diesel emergency generators, use the Compression Ignition Emergency Generator Application.

Engine Data

Date of construction:	
Has the engine been modified or reconstructed? ☐ Yes, reconstructed/modified (*circle one*) If yes, date: ☒ No	
Fuel(s) burned in the engine (check all that apply): ☐ Gasoline ☒ Natural Gas ☐ LPG ☐ Other (please specify):	Engine Manufacturer: Cummins Power Generations Horsepower: 2,463 bhp Date of Manufacture: TBD
Will the engine be used for peak shaving or supply power to the electrical grid? ☐ Yes ☒ No	
Has the engine been certified to meet the applicable emission standards of 40 CFR Part 60, Subpart JJJJ? ☒ Yes ☐ No	
Will the engine be located at a facility that is a major source of HAPs? ☐ Yes ☒ No	
Will the engine be located at a residential, commercial, or institutional facility? ☐ Yes ☒ No	
Owner/Operator's identification number/name for the engine: EP-20020, Generator Set #2	

Facility Information

Company Name: Abengoa Bioenergy Biomass of Kansas, LLC	Source ID number: 1890231
Source Location	
Facility name: Abengoa Bioenergy Biomass of Kansas, LLC	
Street Address: TBD	County: Stevens County
City, State, Zip: Hugoton, KS 67951	Section, Township, Range: T33S, R37W, Sec 18
Mailing Address (if different)	
Street Address: 16150 Main Circle Drive, Suite 200	
City, State, Zip: Chesterfield, MO 63017	
Contact Information	
Name: Robert Wildgen	Telephone Number: (636) 728-4515
Email: Robert.Wildgen@bioenergy.abengoa.com	Fax Number: (636) 536-6175

I certify that the above information is true, accurate, and complete.

Signature: _____ Date: 10/15/12

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Kansas Department of Health and Environment – Bureau of Air
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Application for Approval

Spark Ignition Emergency Generators

This approval is suitable for spark ignition emergency generators used only for back-up power when the primary electric power is interrupted during emergency situations or for short periods to perform maintenance and operational readiness testing. The KDHE believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions.

For diesel emergency generators, use the Compression Ignition Emergency Generator Application.

Engine Data

Date of construction:	
Has the engine been modified or reconstructed? ☐ Yes, reconstructed/modified (*circle one*) If yes, date: ☒ No	
Fuel(s) burned in the engine (check all that apply): ☐ Gasoline ☒ Natural Gas ☐ LPG ☐ Other (please specify):	Engine Manufacturer: Cummins Power Generations Horsepower: 2,463 bhp Date of Manufacture: TBD
Will the engine be used for peak shaving or supply power to the electrical grid? ☐ Yes ☒ No	
Has the engine been certified to meet the applicable emission standards of 40 CFR Part 60, Subpart JJJJ? ☒ Yes ☐ No	
Will the engine be located at a facility that is a major source of HAPs? ☐ Yes ☒ No	
Will the engine be located at a residential, commercial, or institutional facility? ☐ Yes ☒ No	
Owner/Operator's identification number/name for the engine: EP-20030, Generator Set #3	

Facility Information

Company Name: Abengoa Bioenergy Biomass of Kansas, LLC	Source ID number: 1890231
Source Location	
Facility name: Abengoa Bioenergy Biomass of Kansas, LLC	
Street Address: TBD	County: Stevens County
City, State, Zip: Hugoton, KS 67951	Section, Township, Range: T33S, R37W, Sec 18
Mailing Address (if different)	
Street Address: 16150 Main Circle Drive, Suite 200	
City, State, Zip: Chesterfield, MO 63017	
Contact Information	
Name: Robert Wildgen	Telephone Number: (636) 728-4515
Email: Robert.Wildgen@bioenergy.abengoa.com	Fax Number: (636) 536-6175

I certify that the above information is true, accurate, and complete.

Signature: _____ Date: 10/15/12

Please complete the above form for each engine and fax to (785) 291-3953, or mail to the above address.

Kansas Department of Health and Environment – Bureau of Air
1000 SW Jackson, Suite 310, Topeka, KS 66612
Phone: (785) 296-1570 Fax: (785) 291-3953

Application for Approval

Spark Ignition Emergency Generators

This approval is suitable for spark ignition emergency generators used only for back-up power when the primary electric power is interrupted during emergency situations or for short periods to perform maintenance and operational readiness testing. The KDHE believes that 500 hours is an appropriate default assumption for estimating the number of hours that an emergency generator could be expected to operate under worst-case conditions.

For diesel emergency generators, use the Compression Ignition Emergency Generator Application.

Engine Data

Date of construction:	
Has the engine been modified or reconstructed? ☐ Yes, reconstructed/modified (*circle one*) If yes, date: ☒ No	
Fuel(s) burned in the engine (check all that apply): ☐ Gasoline ☒ Natural Gas ☐ LPG ☐ Other (please specify):	Engine Manufacturer: Cummins Power Generations Horsepower: 2,463 bhp Date of Manufacture: TBD
Will the engine be used for peak shaving or supply power to the electrical grid? ☐ Yes ☒ No	
Has the engine been certified to meet the applicable emission standards of 40 CFR Part 60, Subpart JJJJ? ☒ Yes ☐ No	
Will the engine be located at a facility that is a major source of HAPs? ☐ Yes ☒ No	
Will the engine be located at a residential, commercial, or institutional facility? ☐ Yes ☒ No	
Owner/Operator's identification number/name for the engine: EP-20040, Generator Set #4	

Facility Information

Company Name: Abengoa Bioenergy Biomass of Kansas, LLC	Source ID number: 1890231
Source Location	
Facility name: Abengoa Bioenergy Biomass of Kansas, LLC	
Street Address: TBD	County: Stevens County
City, State, Zip: Hugoton, KS 67951	Section, Township, Range: T33S, R37W, Sec 18
Mailing Address (if different)	
Street Address: 16150 Main Circle Drive, Suite 200	
City, State, Zip: Chesterfield, MO 63017	
Contact Information	
Name: Robert Wildgen	Telephone Number: (636) 728-4515
Email: Robert.Wildgen@bioenergy.abengoa.com	Fax Number: (636) 536-6175

I certify that the above information is true, accurate, and complete.

Signature: Date: 10/15/12

Please complete the above form for each engine and fax to (785) 291-3953, or mail to the above address.

Supplemental Information

Disclaimer:
Summaries and other statements in this application form are intended solely as guidance, cannot be used to bind the agency, and are not a substitute for reading applicable statutes, rules, and regulations (including, but not limited to, 40 CFR Part 60, Subpart JJJJ, and 40 CFR Part 63, Subpart ZZZZ.) The federal regulations referenced in this form are available online at http://ecfr/gpoaccess.gov.

Definitions

Commercial facility – establishments such as office buildings, hotels, stores, telecommunications facilities, restaurants, financial institutions such as banks, doctor's offices, and sports and performing arts facilities.

Date of Construction – the date the engine is ordered by the owner or operator.

Date of Manufacture – The date on which the engine was originally built by the manufacturer.

Emergency Stationary Internal Combustion Engine – any stationary internal combustion engine whose operation is limited to emergency situations and required testing and maintenance. Examples include stationary ICE used to produce power for critical networks or equipment (including power supplied to portions of a facility) when electric power from the local utility (or the normal power source, if the facility runs on its own power production) is interrupted, or stationary ICE used to pump water in the case of fire or flood, etc. Stationary SI ICE used for peak shaving are **not** considered emergency stationary ICE. Stationary ICE used to supply power to an electric grid or that supply power as part of a financial arrangement with another entity are **not** considered to be emergency engines.

Hazardous Air Pollutant (HAP) – any air pollutant listed in or pursuant to section 112(b) of the Clean Air Act.

Institutional facility – establishments such as medical centers, nursing homes, research centers, institutions of higher education, correctional facilities, elementary and secondary schools, libraries, religious establishments, police stations, and fire stations.

Liquefied Petroleum Gas (LPG) – any liquefied hydrocarbon gas obtained as a by-product in petroleum refining or natural gas production.

Major source – means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any HAP or 25 tons per year or more of any combination of HAPs.

Modification – any physical change in, or change in the method of operation of, an existing engine that increases the amount of any air pollutant emitted into the atmosphere by that facility or which results in the emission of any air pollutant into the atmosphere not previously emitted.

Peak Shaving – the process of using local electricity generation for the express purpose of "shaving off" a facility's peak power demand to lower the source's overall electrical costs.

Reconstruct – to replace or refurbish components of an existing engine to such an extent that the fixed capital cost of the new and refurbished components exceeds 50 percent of the fixed capital cost of a new engine.

Spark Ignition Internal Combustion Engine – 1) a gasoline-fueled engine, or 2) any other type of engine with a spark plug (or other sparking device) and with operating characteristics significantly similar to the theoretical Otto combustion cycle.

Residential Facility – establishments such as homes or apartment buildings.

Regulatory Summary

40 CFR Part 60, Subpart JJJJ (NSPS JJJJ) Requirements

Applicability – 40 CFR 60.

An emergency SI ICE with a brake horsepower greater than 25 HP is subject to NSPS JJJJ if:

- Construction commenced after June 12, 2006 AND the engine was manufactured after January 1, 2009, OR
- The engine was modified or reconstructed after June 12, 2006

Emission Standards – 40 CFR 60.4233

- Owners and operators of stationary SI ICE shall comply with the emission standards of §60.4233 based on engine power, fuels used, and date of manufacture.

Fuel Requirements – 40 CFR 60.4235

- Owners and operators of stationary SI ICE that burn gasoline shall use gasoline that meets the per gallon sulfur limit in 40 CFR 80.195.

Importing and Installing Requirements – 40 CFR 60.4236

- After January 1, 2011, owners and operators may not install engines that do not meet the applicable emission standards in 40 CFR 60.2333.

Monitoring Requirements – 40 CFR 60.4237

- Owners of operators of the following SI emergency engines that do **not** meet the standards applicable to non-emergency engines shall install a non-resettable hour meter:
  - Engines ≥ 500 HP that were built on or after July 1, 2010
  - Engines between 130 HP and 500 HP that were built on or after January 1, 2011
  - Engines < 130 HP built on or after July 1, 2008

Compliance Requirements – 40 CFR 60.4243

- Maintenance checks and readiness testing of emergency stationary SI ICE is limited to 100 hours per year. There is no time limit on the use of such units in emergency situations.
  - If Federal, State, or local standards require more than 100 hours of maintenance and testing, the owner or operator shall maintain records of these requirements.
  - Emergency SI ICE may operate up to 50 hours per year in non-emergency situations. This operating time cannot be used for peak shaving or to generate income for the facility (e.g. supplying power to the grid) and shall be counted towards the 100 hour limit.
- Owners or operators of natural gas SI engines may use propane as an alternative fuel for up to 100 hours per year during emergency operations.

Reporting and Recordkeeping Requirements – 40 CFR 60.4245

- Owners and operators of all SI ICE shall maintain the following records:
  - All notifications submitted to comply with NSPS JJJJ
  - Maintenance conducted on the engine
  - Documentation from the manufacturer of certification to applicable emission standards
- The owner or operator shall keep records of all operation of the engine. The owner shall record the date and time of operation of the engine and the reason the engine was in operation.
- The owner or operator of an SI ICE ≥ 500 HP that is not certified to meet the emission standards of §60.4231 shall submit an initial notification as specified in §60.4245(c).

40 CFR Part 63, Subpart ZZZZ (MACT ZZZZ) Requirements

Applicability – 40 CFR 63.6590
Use the table below to determine whether the engine is new or existing.
Engines are considered new for MACT ZZZZ if they commence construction or reconstruction after the applicable date, summarized below. Engines constructed before that date are considered existing.

Source Type	Engine Size	Construction/Reconstruction Commences after…
Major	> 500 HP	12/19/02
Major	≤ 500 HP	6/12/06
Area	Any	6/12/06

- The following engines are **not** required to meet the requirements of MACT ZZZZ :
  - Existing emergency ICE >500 HP at major sources.
  - New emergency ICE >500 HP at major sources.
    - Submit an initial notification as specified in 40 CFR 63.6645(f).
  - Existing emergency ICE at residential, commercial, or institutional facilities.
- The following SI ICE shall comply with MACT ZZZZ by complying with NSPS JJJJ, as applicable:
  - New emergency ICE at area sources.
  - New emergency ICE ≤ 500 HP at major sources

Existing emergency ICE of any size at area sources and existing emergency ICE ≤ 500 HP at major sources shall comply with the following requirements, as applicable.

Compliance Date – 40 CFR 63.6595
- The owner or operator shall comply with the requirements of MACT ZZZZ by October 19, 2013.

Operation and Maintenance Requirements – 40 CFR 63.6602, 63.6603, & 63.6625
- Existing emergency ICE shall be equipped with a non-resettable hour meter. [§63.6625(f)]
- The owner or operator shall comply with the work practice requirements in Table 2c and 2d, as applicable (summarized below). [§63.6602 & §63.6603]
  - The owner or operator may petition the Administrator for alternative work practices.

Engine	Meet the following, except during startup	During periods of startup:
Existing Emergency SI ICE ≤ 500 HP at Major Sources of HAP, and Existing Emergency SI ICE at Area Sources of HAP	a. Change oil and filter every 500 hours of operation or annually* b. Inspect spark plugs every 1,000 hours of operation or annually* c. Inspect all hoses and belts every 500 hours of operation or annually*, and replace as necessary.	Minimize the engine's time spent at idle and minimize the engine's startup time at startup to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the non-startup emission limitations apply.

* Whichever comes first.

- The owner or operator may utilize an oil analysis program as described in 40 CFR 63.6625(j) in order to extend the specified oil change requirement.
- Existing emergency ICE shall be operated and maintained according to the manufacturer's emission-related written instructions or an alternative maintenance plan that minimizes emissions. [§ 63.6625(e)]

Recordkeeping Requirements – 40 CFR 63.6655
- The owner or operator shall keep records of maintenance conducted on the engine.
- Existing emergency ICE that do not meet the standards applicable to non-emergency engines shall keep records of engine operation as specified at §63.6655(f).

APPENDIX B
VENDOR SPECIFICATION SHEET

Model: C1750 N6C
Frequency: 60 Hz
Fuel Type: Natural Gas MI 76 +
Emissions Performance NOx: 350 mg/Nm^3 (0.9 g/hp-h)
LT Water Inlet Temperature: 50°C (122°F)
HT Water Outlet Temp: 110°C (230°F)

Generator set data sheet
1750 kW continuous

Our energy working for you.™

Power Generation

Measured Sound Performance Data Sheet:	MSP-1062
Prototype Test Summary Data:	PTS-283
Remote Radiator Cooling Outline:	0500-5092

Fuel Consumption (ISO3046/1)	See Note	100% of Rated Load	90% of Rated Load	75% of Rated Load	50% of Rated Load
Fuel Consumption (LHV) ISO3046/1, kW (MMBTU/hr)	2,4,6,7	4648 (15.87)	4184 (14.29)	3556 (12.14)	2546 (8.7)
Mechanical Efficiency ISO3046/1, percent	2,4,7	39.5%	39.6%	38.9%	36.5%
Electrical Efficiency ISO3046/1, percent	2,4,6,7	37.7%	37.6%	36.9%	34.4%

Engine	
Engine Manufacturer	Cummins
Engine Model	QSV91G
Configuration	V18
Displacement, L (cu.in)	91.6 (5591)
Aspiration	Turbocharged (4)
Gross Engine Power Output, kWm (hp)	1837 (2463)
BMEP, bar (psi)	16 (232)
Bore, mm (in)	180 (7.09)
Stroke, mm (in)	200 (7.87)
Rated Speed, rpm	1500
Piston Speed, m/s (ft/min)	10 (1968)
Compression Ratio	12:1
Lube Oil Capacity, L (qt)	560 (592)
Overspeed Limit, rpm	1800
Regenerative Power, kW	N/A
Full Load Lubricating oil consumption, g/kWe-hr (g/hp-hr)	0.5 (0.37)
Fuel	
Gas supply pressure to engine inlet, bar (psi)	0.2 (3.0)
Minimum Methane Index	76
Starting System(s)	
Electric starter voltage, volts	24
Minimum battery capacity @ 40 deg.C (104 deg.F), AH	720
Air Starter Pressure, barg (psig)	10.3 (150)
Air Starter Flow Nm^3/s (scfm)	0.37 (780)
Genset Dimensions (see note 1)	
Genset Length, m (ft)	7.36 (24.15)
Genset Width, m (ft)	2.11 (6.91)
Genset Height, m (ft)	2.97 (9.75)
Genset Weight (wet), kg (lbs)	21089 (46,493)

	See Notes	100% of Rated Load	90% of Rated Load	75% of Rated Load	50% of Rated Load
Energy Data					
Continuous Shaft Power, kWm (bhp)	2,10	1837 (2463)	1655 (2219)	1382 (1853)	930 (1247)
Continuous Generator Electrical Output kWe @ 1.0 pf	6,10	1750	1575	1312.5	875
Heat Dissipated in Lube Oil Cooler, kW (MMBTU/h)	5	264 (0.90)	248 (0.85)	228 (0.78)	194 (0.66)
Heat Dissipated in Block, kW (MMBTU/h)	5	474 (1.62)	442 (1.51)	414 (1.41)	347 (1.18)
Total Heat Rejected in LT Circuit, kW (MMBTU/h)	5	530 (1.81)	488 (1.66)	434 (1.48)	349 (1.19)
Total Heat Rejected in HT Circuit, kW (MMBTU/h)	5	564 (1.93)	489 (1.67)	406 (1.38)	281 (0.96)
Unburnt, kW (MMBTU/h)	13	124 (0.42)	119 (0.41)	106 (0.36)	86 (0.29)
Heat Radiated to Ambient, kW (MMBTU/h)	13	325 (1.11)	294 (1.00)	252 (0.86)	185 (0.63)
Available Exhaust heat to 105C, kW (MMBTU/h)	5	1203 (4.10)	1087 (3.71)	952 (3.25)	692 (2.36)
Intake Air Flow					
Intake Air Flow Mass, kg/s (lb/hr)	4	N/A	N/A	N/A	N/A
Intake Air Flow Volume, m3/s @ 0°C (scfm)	4	N/A	N/A	N/A	N/A
Maximum Air Cleaner Restriction, mmHG (in H_2O)		36.70 (19.7)	33.03 (17.7)	27.53 (14.8)	18
Exhaust Air Flow					
Exhaust Gas Flow Mass, kg/s (lb/hr)	4	2.89 (22889)	2.56 (20275)	2.16 (17107)	1.50 (11880)
Exhaust Gas Flow Volume, m3/s (cfm)	4	6.28 (13292)	5.62 (11897)	4.83 (10232)	3.44 (7277)
Exhaust Temperature After Turbine, °C (°F)	2,6	494 (921)	502 (936)	517 (963)	536 (997)
Max Exhaust System Back Pressure, mmHG (in H_2O)	6,14	37.3 (20.0)	37.3 (20.0)	37.3 (20.0)	37.3 (20.0)
Min Exhaust System Back Pressure, mmHG (in H_2O)	6,14	18.7 (10.0)			
HT Cooling Circuit					
HT Circuit Engine Coolant Volume, l (gal)		424 (112)	424 (112)	424 (112)	424 (112)
HT Coolant Flow @ Max Ext Restriction, m^3/h (gal/min)		60 (264)	60 (264)	60 (264)	60 (264)
Maximum HT Engine Coolant Inlet Temp, °C (°F)	8	97 (207)	97 (207)	97 (207)	97 (207)
HT Coolant Outlet Temp, °C (°F)	8	110 (230)	110 (230)	110 (230)	110 (230)
Max Pressure Drop in External HT Circuit, bar (psig)		1.0 (15)	1.0 (15)	1.0 (15)	1.0 (15)
HT Circuit Maximum Pressure, bar (psig)		4.5 (65)	4.5 (65)	4.5 (65)	4.5 (65)
Minimum Static Head, bar (psig)		1.5 (22)	1.5 (22)	1.5 (22)	1.5 (22)
LT Cooling Circuit					
LT Circuit Engine Coolant Volume, l (gal)		295 (78)	295 (78)	295 (78)	295 (78)
LT Coolant Flow @ Max Ext Restriction, m^3/h (gal/min)		38.00 (167)	38.00 (167)	38.00 (167)	38.00 (167)
Maximum LT Engine Coolant Inlet Temp, °C (°F)	9	50 (122)	50 (122)	50 (122)	50 (122)
LT Coolant Outlet Temp, eC (°F) Reference Only	9	60.0 (140)	60.0 (140)	60.0 (140)	60.0 (140)
Max Pressure Drop in External LT Circuit, bar (psig)		1.0 (15)	1.0 (15)	1.0 (15)	1.0 (15)
LT Circuit Maximum Pressure, bar (psig)		4.5 (65)	4.5 (65)	4.5 (65)	4.5 (65)
Minimum Static Head, bar (psig)		1.5 (22)	1.5 (22)	1.5 (22)	1.5 (22)
Emissions					
NO_x Emissions wet, ppm	4	104	104	104	106
NO_x Emissions, mg/Nm^3 @5% O_2 (g/hp-h)	4	350 (0.84)	350 (0.84)	350 (0.85)	350 (0.90)
THC Emissions wet, ppm	13	N/A	N/A	N/A	N/A
THC Emissions, mg/Nm^3 @5% O_2 (g/hp-h)	13	N/A	N/A	N/A	N/A
CH_4 Emissions wet, ppm	13	1575	1600	1710	2025
CH_4 Emissions, mg/Nm^3 @5% O_2 (g/hp-h)	13	1840 (4.42)	1870 (4.48)	1990 (4.83)	2320 (5.96)
NMHC Emissions wet, ppm	13	N/A	N/A	N/A	N/A
NMHC Emissions, mg/Nm^3 @5% O_2 (g/hp-h)	13	N/A	N/A	N/A	N/A
CO Emissions (dry), ppm	13	590	590	588	582
CO Emissions, mg/Nm^3 @5% O_2 (g/hp-h)	13	1050 (2.50)	1050 (2.50)	1040 (2.50)	1020 (2.60)
O2 Emissions (dry), percent	13	9.6	9.6	9.6	9.4
Particulates PM10, g/hp-h	13	N/A	N/A	N/A	N/A

Genset De-rating

Altitude and Temperature Derate Multiplication Factor

Barometer		Altitude		Table A *								
In Hg	mbar	Feet	Meters	Derate Multiplier with Grid Parallel Operation								
20.7	701	9843	3000	0.75	0.70	0.70	N/A	N/A	N/A	N/A	N/A	N/A
21.4	723	9022	2750	0.80	0.75	0.75	0.70	N/A	N/A	N/A	N/A	N/A
22.1	747	8202	2500	0.85	0.85	0.80	0.75	0.70	N/A	N/A	N/A	N/A
22.8	771	7382	2250	0.90	0.85	0.85	0.80	0.75	0.70	N/A	N/A	N/A
23.5	795	6562	2000	0.95	0.90	0.85	0.85	0.80	0.75	N/A	N/A	N/A
24.3	820	5741	1750	1.00	1.00	0.90	0.90	0.85	0.80	0.75	N/A	N/A
25.0	846	4921	1500	1.00	1.00	0.95	0.95	0.90	0.85	0.80	0.70	N/A
25.8	872	4101	1250	1.00	1.00	1.00	1.00	0.95	0.90	0.85	0.75	0.70
26.6	899	3281	1000	1.00	1.00	1.00	1.00	1.00	0.95	0.90	0.85	0.75
27.4	926	2461	750	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.90	0.85
28.3	954	1640	500	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	0.90
29.1	983	820	250	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
29.5	995	492	150	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
30.0	1012	0	0	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
			°C	20	25	30	35	40	45	50	55	60
			°F	68	77	86	95	104	113	122	131	140
			Air Filter Inlet Temperature									

* Based on SAE standard ambient pressure vs. altitude. Assumes LT return temperature is 10C above air filter inlet.

Temperature & Altitude Derate

1. Determine derate multiplier vs. temperature and altitude in Table A or B depending upon your operating condition.
2. Assumes the LT return temperature is 10 deg C above the air filter inlet with a maximum LT temperature of 50 deg C.
3. If the LT temperature exceeds 50 deg C, consult factory for recommendations.
4. Altitude is based upon SAE standard ambient pressure vs. altitude. For low barometric conditions add 150m (500 ft) to site altitude.

Barometer		Altitude		Table B *								
In Hg	mbar	Feet	Meters	Derate Multiplier Off Grid (Island or Load Share)								
20.7	701	9843	3000	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21.4	723	9022	2750	0.71	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22.1	747	8202	2500	0.76	0.72	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22.8	771	7382	2250	0.81	0.77	0.72	N/A	N/A	N/A	N/A	N/A	N/A
23.5	795	6562	2000	0.86	0.81	0.77	0.71	N/A	N/A	N/A	N/A	N/A
24.3	820	5741	1750	0.91	0.86	0.82	0.76	0.70	N/A	N/A	N/A	N/A
25.0	846	4921	1500	0.96	0.92	0.97	0.82	0.77	N/A	N/A	N/A	N/A
25.8	872	4101	1250	1.00	0.98	0.87	0.87	0.82	0.73	N/A	N/A	N/A
26.6	899	3281	1000	1.00	1.00	0.94	0.94	0.87	0.79	N/A	N/A	N/A
27.4	926	2461	750	1.00	1.00	0.98	0.98	0.95	0.85	N/A	N/A	N/A
28.3	954	1640	500	1.00	1.00	1.00	1.00	1.00	0.92	0.75	N/A	N/A
29.1	983	820	250	1.00	1.00	1.00	1.00	1.00	0.98	0.83	0.70	N/A
29.5	995	492	150	1.00	1.00	1.00	1.00	1.00	1.00	0.90	0.82	N/A
30.0	1012	0	0	1.00	1.00	1.00	1.00	1.00	1.00	0.92	0.87	0.72
			°C	20	25	30	35	40	45	50	55	60
			°F	68	77	86	95	104	113	122	131	140
			Air Filter Inlet Temperature									

* Based on SAE standard ambient pressure vs. altitude. Assumes LT return temperature is 10C above air filter inlet.

Methane Number Capability

Load (Percent of Rated)			
100%	90%	75%	50%
76	70	62	52

Heat Rejection Factor (altitude and ambient) for HT and LT Circuits

Barometer		Altitude		Table C								
In Hg	mbar	Feet	Meters	Multiplier for HT & LT Heat Rejection vs Alt & Temp.								
20.7	701	9843	3000	1.11	1.13	1.14	1.15	1.17	1.18	1.19	1.20	1.22
21.4	723	9022	2750	1.10	1.12	1.13	1.14	1.15	1.17	1.18	1.19	1.21
22.1	747	8202	2500	1.09	1.10	1.12	1.13	1.14	1.16	1.17	1.18	1.20
22.8	771	7382	2250	1.08	1.09	1.11	1.12	1.13	1.14	1.16	1.17	1.18
23.5	795	6562	2000	1.07	1.08	1.09	1.11	1.12	1.13	1.15	1.16	1.17
24.3	820	5741	1750	1.06	1.07	1.08	1.10	1.11	1.12	1.14	1.15	1.16
25.0	846	4921	1500	1.05	1.06	1.07	1.09	1.10	1.11	1.12	1.14	1.15
25.8	872	4101	1250	1.04	1.05	1.06	1.07	1.09	1.10	1.11	1.13	1.14
26.6	899	3281	1000	1.02	1.04	1.05	1.06	1.08	1.09	1.10	1.12	1.13
27.4	926	2461	750	1.01	1.03	1.04	1.05	1.07	1.08	1.09	1.10	1.12
28.3	954	1640	500	1.00	1.02	1.03	1.04	1.05	1.07	1.08	1.09	1.11
29.1	983	820	250	0.99	1.00	1.02	1.03	1.04	1.06	1.07	1.08	1.10
29.5	995	492	150	0.99	1.00	1.01	1.03	1.04	1.05	1.06	1.08	1.09
30.0	1012	0	0	0.98	0.99	1.01	1.02	1.03	1.05	1.06	1.07	1.08
			°C	20	25	30	35	40	45	50	55	60
			°F	68	77	86	95	104	113	122	131	140
			Air Filter Inlet Temperature									

LT & HT Circuit Heat Rejection Calculation

1. Determine derate multiplier vs. temperature derate per above.
2. Using the multiplier from #1 above as the percent load factor determine the Heat rejection from the previous page.
3. From Table C find the HT and LT circuit multiplier.
4. Multiply the result of step 2 by the result of step 3 to obtain the heat rejection at your altitude and temperature.

Alternator Data

Voltage Range	Connection Configuration	Temp Rise Degrees C	Duty[11] Cycle	Single Phase Factor	Maximum Surge kVA[12]	Alternator Data Sheet	Feature Code
380-416	Wye, 3 Phase	80	C	N/A	7267	515	B829-2
480	Wye, 3 Phase	80	C	N/A	7361	334	B653-2
440-480	Wye, 3 Phase	80	C	N/A	7695	335	B588-2
416-480	Wye, 3 Phase	105	C	N/A	7695	335	B627-2
600	Wye, 3 Phase	80	C	N/A	7361	334	B589-2
380-416	Wye, 3 Phase	105	C	N/A	7361	334	B831-2
440-480	Wye, 3 Phase	105	C	N/A	7361	334	B832-2
416-480	Wye, 3 Phase	125	C	N/A	7361	334	B654-2
440-480	Wye, 3 Phase	125	C	N/A	6716	333	B650-2
600	Wye, 3 Phase	125	C	N/A	6716	333	B651-2
4160	Wye, 3 Phase	80	C	N/A	6335	518	B590-2
4160	Wye, 3 Phase	105	C	N/A	7926	324	B834-2
12470-13800	Wye, 3 Phase	80	C	N/A	6800	522	B591-2
12470-13800	Wye, 3 Phase	105	C	N/A	5948	521	B484-2
13200-13800	Wye, 3 Phase	80	C	N/A	5948	521	B656-2

Continuous Rating Definition

Applicable for supplying power continuously to a constant load up to the full output rating for unlimited hours. No sustained overload capability is available for this rating. Consult authorized distributor for rating. (Equivalent to Continuous Power in accordance with ISO8528, ISO3046, AS2789, DIN6271, and BS5514). This rating is not applicable to all generator set models.

Notes

1) Weights and set dimesions represent a generator set with its standard features only. See outline drawing for other configurations.
2) At ISO3046 reference conditions, altitude 1013 mbar (30in Hg), air inlet temperature 25°C (77°F)
3) Nominal performance +/- 2 ½%.
4) According to ISO 3046/I with a tolerance of +5%/- 0%
5) Production variation/tolerance ±5%
6) At electrical output of 1.0 Power Factor
7) Tested using pipeline natural gas with LHV of 33.44mJ/Nm^3 (905 BTU/ft^3)
8) Outlet temperature controlled by thermostat. Inlet temperature for reference only.
9) Inlet temperature controlled by thermostat. Outlet temperature for reference only.
10) With engine driven coolant pump
11) Standby (S), Prime (P), Continuous (C) ratings.
12) Maximum rated starting kVA that results in minimum of 90% of rated sustained voltage during starting.
13) Tolerance +/- 15%.
14) Exhaust system back pressure is a rated load and will decrease at lower loads.

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Power Generation

APPENDIX C
POTENTIAL TO EMIT CALCULATIONS

Abengoa Bioenergy Biomass of Kansas, LLC
Biorefinery Facility
Hugoton, Kansas

Rev. 0

UNCONTROLLED Potential to Emit Summary (LB/HR)

Emission Point No.	Emission Unit(s)	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	CO	VOC	Single HAP - HCl	Total HAPs	Direct CO_2 + CO_2e
EP-20001	**Biomass-Fired Stoker Boiler #1 120% of Nominal Design Load**	**3,643.56**	**3,254.09**	**2,799.70**	**377.38**	**1,326.94**	**110.04**	**8.50**	**130.02**	**138.80**	**109,966**
EP-20001	Biomass-Fired Stoker Boiler #1 30% Reduced Load	1,029.48	919.44	791.05	107.39	374.93	31.09	0.72	36.74	39.17	16,548
EP-20010	Generator Set #1	0.063	0.063	0.063	4.79	0.0037	15.61	0.74	--	0.45	734
EP-20020	Generator Set #2	0.063	0.063	0.063	4.79	0.0037	15.61	0.74	--	0.45	734
EP-20030	Generator Set #3	0.063	0.063	0.063	4.79	0.0037	15.61	0.74	--	0.45	734
EP-20040	Generator Set #4	0.063	0.063	0.063	4.79	0.0037	15.61	0.74	--	0.45	734
Total During Boiler Start-Up With All 4 Generators		**1,029.73**	**919.69**	**791.30**	**126.54**	**374.94**	**93.53**	**3.68**	**36.74**	**41.0**	**19,483**

Abengoa Bioenergy Biomass of Kansas, LLC
Biorefinery Facility
Hugoton, Kansas

Rev. 0

CONTROLLED Potential to Emit Summary (LB/HR)

Emission Point No.	Emission Unit(s)	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	CO	VOC	Single HAP - HCl	Total HAPs	Direct CO_2 + CO_2e
EP-20001	**Biomass-Fired Stoker Boiler #1 120% of Nominal Design Load**	**15.77**	**14.99**	**14.08**	**207.56**	**106.16**	**110.04**	**2.55**	**1.30**	**4.20**	**109,966**
EP-20001	Biomass-Fired Stoker Boiler #1 30% Reduced Load	4.46	4.24	3.98	107.39	29.99	31.09	0.72	0.37	1.19	16,548
EP-20010	Generator Set #1	0.063	0.063	0.063	4.79	0.0037	15.61	0.74	--	0.45	734
EP-20020	Generator Set #2	0.063	0.063	0.063	4.79	0.0037	15.61	0.74	--	0.45	734
EP-20030	Generator Set #3	0.063	0.063	0.063	4.79	0.0037	15.61	0.74	--	0.45	734
EP-20040	Generator Set #4	0.063	0.063	0.063	4.79	0.0037	15.61	0.74	--	0.45	734
Total During Boiler Start-Up With All 4 Generators		**4.71**	**4.49**	**4.23**	**126.54**	**30.01**	**93.53**	**3.68**	**0.37**	**2.99**	**19,483**

Abengoa Bioenergy Biomass of Kansas, LLC Biorefinery Facility Hugoton, Kansas	Rev. 0

Direct GHG Summary (LB/HR)

Pollutants	EP-20001 Biomass-Fired Stoker Boiler #1 120% of Nominal Design Load	EP-20001 Biomass-Fired Stoker Boiler #1 30% Reduced Load	EP-20010 Generator Set #1	EP-20020 Generator Set #2	EP-20030 Generator Set #3	EP-20040 Generator Set #4
CO_2	107,789	16,532	733	733	733.1	733
CH_4	35	0.31	0	0.014	0.014	0
CH_4 => CO_2 Equivalent (1)	741	7	0	0.29	0.29	0
N_2O	5	0.03	0	0.0014	0.0014	0
N_2O => CO_2 Equivalent (1)	1,436	10	0	0.43	0.43	0
SF_6	0	0	0	0	0	0
SF_6 => CO_2 Equivalent (1)	0	0	0	0	0	0
Total CO_2 + CO_2e	**109,966**	**16,548**	**734**	**734**	**734**	**734**

(1) To incorporate and evaluate non-CO_2 gases, the mass estimates of these gases were converted to their CO_2 equivalent (CO_2e). To calculate the CO_2 equivalent, the mass of the non-CO_2 gas is multiplied by the non-CO_2 gas's Global Warming Potential (GWP), see note 2 below. The GWPs for CH_4, N_2O and SF_6 are 21, 310 and 23,900, respectively, as obtained from 40 CFR Part 98 Table A-1 of the Greenhouse Gas Reporting Program (GHGRP).

(2) Global Warming Potentials (GWPs) were developed by the Intergovernmental Panel on Climate Change (IPCC) to quantify the globally averaged relative radiative forcing effects of a given GHG, using CO_2 as the reference gas. In 1996, the IPCC published a set of GWPs for the most commonly measured greenhouse gases in its Second Assessment Report (SAR). In 2001, the IPCC published its Third Assessment Report (TAR), which adjusted the GWPs to reflect new information on atmospheric lifetimes and an improved calculation of the radiative forcing of CO_2. However, SAR GWPs are still used by international convention and the U.S. to maintain the value of the CO_2 "currency". To maintain consistency with international practice, the California Climate Action Registry requires participants to use GWPs from the SAR when determining de minimis emissions, establishing baselines, and making baseline adjustments.

EP-20001
Biomass-Fired Stoker Boiler

Fuel Configuration

Basis:

AP-42 Section 1.6 Wood Residue Combustion in Boilers, Final Section, September 2003.
The biomass-fired boiler system consists of one (1) water-cooled vibrating grate (stoker) boiler.
Gaseous fuel will be supplied to the biomass-fired stoker boiler system from the wastewater treatment system to optimize the energy available from the biogas.
ABNT Cogeneration Model used to determine blended fuel rate, composition and HHV. Final engineering of the biomass-fired stoker boiler system has not been completed.
California Climate Action Registry (CCAR) General Reporting Protocol, Version 3.1, January 2009.
The fuel moisture contents can vary from 5 to 75 wt% depending of residue type and storage operations.

The typical feed rate volumes differ from the nominal WORST CASE to the nominal TYPICAL scenario due to the actual boiler design basis constant being based on the plant's steam demand requirements. For the fuel balance, a constant amount of steam is generated, which requires a constant energy demand. The energy demand is supplied by the fuel lower heating value after the fuel moisture has been evaporated. The higher heating value energy input does not remain constant because the different fuel scenarios create different blended fuel compositions.

In addition to firing biomass and biogas, the biomass-fired stoker boiler will be capable of firing on natural gas during normal operations as needed, as well as firing on a combination of natural gas, liquid fuel (i.e. EH stillage syrup) and biogas in the event of a solid fuel failure. "Start-up" emissions are based on the combustion of natural gas only, without any add-on control devices. All other firing scenarios will only be possible when the add-on control devices are operational.
Boiler limited to less than 10% natural gas annual capacity.

Criteria:

Number of Solids-Fired Boilers	1	
Total Area 20000 Heat Input - Permit	500 MMBtu/hr	Based on Maximum WORST CASE fuel blend. Includes 20% factor of safety applied to NOMINAL EH Residuals.
Annual Operations	8,760 hr/yr	

Source Details:

		Rate	Stack Diameter	Release Height	Stack Area	Gas Velocity		Gas Exit Temperature	
ID	Emission Source	(cfm)	(in)	(ft)	(ft^2)	(ft/s)	(m/s)	(deg F)	(deg K)
EP-20001	Biomass-Fired Stoker Boiler #1	264,000	120	160	78.54	56.02	17.07	300	422

EP-20001
Biomass-Fired Stoker Boiler

Combined Fuels Specifications:	Nominal TYPICAL Fuel Blend					
Fuel Component (Dry Basis)	EH Lignin-Rich Stillage (wt%)	EH Thin Stillage Syrup (wt%)	Corn Stover (wt%)	Biogas (wt%)	WWTP Sludge (wt%)	Blended Biomass (wt%)
Carbon	48.16	34.98	40.74	46.46	48.05	42.68
Hydrogen	6.28	6.12	5.48	9.97	6.88	6.30
Oxygen	25.04	47.39	35.34	43.49	35.31	34.89
Nitrogen	1.77	1.98	0.40	0.00	7.43	1.40
Sulfur	0.33	2.62	0.04	0.08	0.02	0.86
Ash	18.07	6.39	17.79	0.00	2.30	13.53
Chlorine	0.35	0.52	0.21	0.00	0.01	0.34
Total wt%	100.0	100.0	100.0	100.0	100.0	100.0
Moisture	54.4%	50.0%	15.0%	4.1%	80.0%	45.3%
Feed Rate (dry ton/day)	320.6	209.5	185.3	52.7	3.0	771.10
Feed Rate (wet lb/hr)	58,579	34,917	18,167	4,579	1,250	117,492

Combined Fuels Energy:	Nominal TYPICAL Fuel Blend					
HHV (Btu/dry lb)	7,880	6,250	6,920	9,631	9,225	7,331.35
HHV (MMBtu/dry ton)	15.76	12.50	13.84	19.26	18.45	14.66
Energy (MMBtu/hr)	210.53	109.11	106.86	42.30	2.31	471.10

Combined Fuels Specifications:	Maximum WORST CASE Fuel Blend					
Fuel Component (Dry Basis)	EH Lignin-Rich Stillage (wt%)	EH Thin Stillage Syrup (wt%)	Corn Stover (wt%)	Biogas (wt%)	WWTP Sludge (wt%)	Blended Biomass (wt%)
Carbon	48.16	34.98	40.74	46.46	48.05	42.95
Hydrogen	6.28	6.12	5.48	9.97	6.88	6.41
Oxygen	25.04	47.39	35.34	43.49	35.31	34.83
Nitrogen	1.77	1.98	0.40	0.00	7.43	1.54
Sulfur	0.33	2.62	0.04	0.08	0.02	0.98
Ash	18.12	6.46	17.76	0.00	2.30	12.98
Chlorine	0.30	0.45	0.24	0.00	0.01	0.31
Total wt%	100.0	100.0	100.0	100.0	100.0	100.0
Moisture	54.4%	50.0%	15.0%	4.1%	80.0%	47.8%
Feed Rate (dry ton/day)	384.7	251.4	109.3	63.2	3.6	812.23
Feed Rate (wet lb/hr)	70,291	41,900	10,718	5,495	1,250	129,655

Combined Fuels Energy:	Maximum WORST CASE Fuel Blend					
HHV (Btu/dry lb)	7,880	6,250	6,920	9,631	9,225	7,388.47
HHV (MMBtu/dry ton)	15.76	12.50	13.84	19.26	18.45	14.78
Energy (MMBtu/hr)	252.62	130.94	63.05	50.72	2.77	500.09

EP-20001
Biomass-Fired Stoker Boiler

Combined Fuels Specifications:	Solid Fuel Failure Fuel Blend [Liquid (i.e. EH Stillage Syrup) and Gaseous Fuels Only]						
Fuel Component (Dry Basis)	EH Lignin-Rich Stillage (wt%)	EH Thin Stillage Syrup (wt%)	Corn Stover (wt%)	Natural Gas (wt%)	Biogas (wt%)	WWTP Sludge (wt%)	Blended Biomass (wt%)
Carbon	48.16	34.98	40.74	64.84	46.46	48.05	45.90
Hydrogen	6.28	6.12	5.48	20.85	9.97	6.88	11.25
Oxygen	25.04	47.39	35.34	1.41	43.49	35.31	32.49
Nitrogen	1.77	1.98	0.40	12.90	0.00	7.43	5.12
Sulfur	0.33	2.62	0.04	0.00	0.08	0.02	1.45
Ash	18.07	6.39	17.79	0.00	0.00	2.30	3.51
Chlorine	0.35	0.52	0.21	0.00	0.00	0.01	0.29
Total wt%	100.0	100.0	100.0	100.0	100.0	100.0	100.00
Moisture	54.4%	50.0%	15.0%	0.001%	4.1%	80.0%	36.8%
Fee Rate (dry ton/day)	0.0	209.5	0.0	119.1	52.7	0.0	381
Feed Rate (wet lb/hr)	0	34,917	0	9,925	4,579	1,250	50,671

Combined Fuels Energy:	Solid Fuel Failure Fuel Blend [Liquid (i.e. EH Stillage Syrup) and Gaseous Fuels Only]						
HHV (Btu/dry lb)	5,550	6,250	6,920	20,160	9,631	9,225	11,062.12
HHV (MMBtu/dry ton)	11.10	12.50	13.84	40.32	19.26	18.45	22.12
Energy (MMBtu/hr)	0.00	109.11	0.00	200.09	42.30	0.00	351.50

EP-20001
Biomass-Fired Stoker Boiler

Process Vents Flow:

Fuel Components		12024 Digester Vent Gas (lb/hr)	16023 Propagator Vent (lb/hr)	16012 Saccharification Vent (lb/hr)	19026 Stillage Handling Vent (lb/hr)	2133 Ethanol Loadout Vent (lb/hr)	1916 + 1919 Ammonia Tank Vent (lb/hr)	Combined Process Vents (lb/hr)	Component HHV (Btu/lb)	Carbon (lb-mol/hr)
Oxygen	O_2	407	7,171	17	69	2	0.10	7,666.10	--	--
Nitrogen	N_2	1,341	26,119	61	231	12	0.30	27,764.30	--	--
Hydrogen Sulfide	H_2S	0.07	0.04	0.03	0.008	0.002	4.30E-04	0.15	7,100	--
Nitrogen Dioxide	NO_2	0.40	0.10	0.10	0.04	1.50E-04	4.60E-04	0.64		
Ammonia	NH_3	0	0	0	0	0	0.03	0.03	9,668	--
Methane	CH_4	0.003	0	0.01	0	0	1.20E-04	0.01	23,879	0.00
Ethane	C_2H_6	0	0	0	0	0	0	0.00	22,320	--
Ethanol	C_2H_5OH	0.04	0	0	0.001	3	0	3.04	13,161	1.30E-01
Acetic Acid	$C_2H_4O_2$	13	1	0.02	0	0	0	14.02	6,558	4.67E-01
Furfural	$C_5H_4O_2$	8	0.1	0.005	0.02	8.10E-04	0	8.13	--	4.23E-01
Tars / Fusel Oils	$C_{10}H_8$	0	0	0	0	0.60	0	0.63	--	--
Carbon Dioxide	CO_2	1	1,139	10	0.7	7.50E-05	0.3	1,151.00	--	26.15
Water/Inerts	H_2O/Inerts	1,101	1,272	6	121	0.03	0.02	2,500.05	--	--
	Total (lb-mol/hr)	2,872	35,702	94	422	18	1	39,108.10	--	27.17

Process Vents Energy:	12024 Digester Vent Gas	16023 Propagator Vent	16012 Saccharification Vent	19026 Stillage Handling Vent	2133 Ethanol Loadout Vent	1916 + 1919 Ammonia Tank Vent	Combined Process Vents
HHV (Btu/lb)	30.07	0.19	6.19	0.17	2,239.80	394.08	3.42
Volumetric Flow (lb-mol/hr)	2,871.51	35,702.24	94.17	421.79	17.63	0.75	39,108.10
Energy (MMBtu/hr)	0.09	0.01	0.00	0.00	0.04	0.00	0.13

EP-20001
Biomass-Fired Stoker Boiler

Biomass-Fired Stoker Boiler Emissions (Nominal TYPICAL Fuel Blend)

Emission Factors:		Combined Fuels	Process Vents	Total		
Criteria Pollutants		(lb/dry ton)	(lb/hr)	(lb/hr)	(lb/MMBtu)	Notes:
NOx		10.12	0.64	325.79	0.70	Predicted NOx for similar fuel combustion for stoker from vendor proposal (approximately 11% fuel N conversion to NOx). Staged combustion to minimize thermal NOx.
SO_2		34.40	0.301	1,105.54	2.35	Predicted SOx for similar fuel combustion for stoker from vendor testing (100% fuel S conversion to SOx).
H_2SO_4 (SAM)		--		67.68	0.14	Based on 4% SO_2 conversion to SO_3 and 100% conversion SO_3 to H_2SO_4.
CO		3.23	Negligible	103.62	0.22	Note 1. Predicted CO for similar fuel combustion for stoker from vendor proposal. Modern combustion practices, staged combustion, fuel/air mixing, large firebox/residence time.
VOC		0.25	Negligible	8.01	0.017	Table 1.6-3, 70% control efficiency for use of modern stoker boiler based on performance test data from similar fuel combustion for stoker.
PM	Filterable	--		3,569.43	7.58	Table 1.6-1 Filterable PM from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
PM_{10}	Filterable	--		3,186.99	6.77	Table 1.6-1 Filterable PM_{10} from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
$PM_{2.5}$	Filterable	--		2,740.81	5.82	Table 1.6-1 Filterable $PM_{2.5}$ from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
PM	Condensible	--		8.01	0.017	Table 1.6-1 Condensible PM from wood residue combustion, bark and wet wood.
PM_{10}	Condensible	--		8.01	0.017	Table 1.6-1 Condensible PM from wood residue combustion, bark and wet wood.
$PM_{2.5}$	Condensible	--		8.01	0.017	Table 1.6-1 Condensible PM from wood residue combustion, bark and wet wood.
Lead		0.0007	Negligible	0.02	4.80E-05	Table 1.6-4
NH_3		--		6.03	0.0128	Note 2 - Predicted 25 ppmv NH_3 slip. Includes NH_3 from gaseous fuel source.
GHG Pollutants						
Natural Gas CO_2		3,130	1,195.93	101,755.94	216.00	Boiler fuel criteria engineering calculations - 100% conversion fuel carbon to CO_2.
CH_4		--		33.24	0.071	CCAR Table C.8 (0.032 kg CH_4/MMBtu). Methane is a combustible boiler fuel.
N_2O		--		4.36	0.009	CCAR Table C.8 (0.0042 kg N_2O/MMBtu).

(1) Emission factors for CO in parts per million (ppm) converted to lb/MMBtu as follows:

EF (lb/MMBtu) = (ppm) x (k) x (F) x (20.9/(20.9-%O_2))

where:

CO =	260 ppm	Vendor Proposal
%O_2 =	3 %	
k = unit conversion, (2.59E-09 x Molecular Weight (M)) lb/dscf = 1 ppm		
k (for CO) =	7.25E-08 (lb/scf)/ppm	
F =	9939.40 dscf/MMBtu	Based on stoichiometric flow
Molecular weight of CO =	28.01	

(2) Emission factors for NH_3 in parts per million (ppm) converted to lb/MMBtu as follows:

EF (lb/MMBtu) = (ppm) x (k) x (F) x (20.9/(20.9-%O_2))

where:

NH_3 =	25 ppm	Vendor Proposal
%O_2 =	3 %	
k = unit conversion, (2.59E-09 x Molecular Weight (M)) lb/dscf = 1 ppm		
k (for NH_3) =	4.41077E-08 (lb/scf)/ppm	
F =	9939.40 dscf/MMBtu	Based on stoichiometric flow
Molecular weight of NH_3 =	17.03	

EP-20001
Biomass-Fired Stoker Boiler

Emissions: Nominal TYPICAL Fuel Blend		Control Efficiency	EP-20001 Biomass-Fired Stoker Boiler Uncontrolled		EP-20001 Biomass-Fired Stoker Boiler Controlled		BACT
Criteria Pollutants		(%)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/MMBtu)
NOx		45%	325.79	1,426.95	179.18	784.82	0.380
SO_2		92%	1,105.54	4,842.28	88.44	387.38	0.188
H_2SO_4 (SAM)		99%	67.68	296.43	0.68	2.96	0.001
CO		0%	103.62	453.87	103.62	453.87	0.220
VOC		70%	8.01	35.07	2.40	10.52	0.005
PM	Filterable	99.8%	3,569.43	15,634.11	7.14	31.27	0.015
PM_{10}	Filterable	99.8%	3,186.99	13,959.02	6.37	27.92	0.014
$PM_{2.5}$	Filterable	99.8%	2,740.81	12,004.76	5.48	24.01	0.012
PM	Condensible	0%	8.01	35.08	8.01	35.08	0.017
PM_{10}	Condensible	0%	8.01	35.08	8.01	35.08	0.017
$PM_{2.5}$	Condensible	0%	8.01	35.08	8.01	35.08	0.017
Lead		0%	0.02	0.10	0.02	0.10	--
NH_3		0%	--	--	6.40	28.04	--
GHG Pollutants							
CO_2		0%	101,756	445,691	101,756	445,691	--
CH_4		0%	33.24	145.59	33.24	145.59	--
N_2O		0%	4.36	19.11	4.36	19.11	--

EP-20001
Biomass-Fired Stoker Boiler

Biomass-Fired Stoker Boiler Emissions (Maximum WORST CASE Fuel Blend)

Emission Factors:		Combined Fuels	Process Vents	Total		Notes:	
Criteria Pollutants		(lb/dry ton)	(lb/hr)	(lb/hr)	(lb/MMBtu)		
NOx		11.13	0.64	377.38	0.76	Predicted NOx for similar fuel combustion for stoker from vendor proposal (approximately 11% fuel N conversion to NOx). Staged combustion to minimize thermal NOx.	
SO_2		39.20	0.301	1326.94	2.65	Predicted SOx for similar fuel combustion for stoker from vendor testing (100% fuel S conversion to SOx).	
H_2SO_4 (SAM)		--		81.23	0.16	Based on 4% SO_2 conversion to SO_3 and 100% conversion SO_3 to H_2SO_4.	
CO		3.25	Negligible	110.04	0.22	Note 1. Predicted CO for similar fuel combustion for stoker from vendor proposal. Modern combustion practices, staged combustion, fuel/air mixing, large firebox/residence time.	
VOC		0.25	Negligible	8.50	0.017	Table 1.6-3, 70% control efficiency for use of modern stoker boiler based on performance test data from similar fuel combustion for stoker.	
PM	Filterable	--		3,635.05	7.27	Table 1.6-1	Filterable PM from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
PM_{10}	Filterable	--		3,245.58	6.49	Table 1.6-1	Filterable PM_{10} from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
$PM_{2.5}$	Filterable	--		2,791.20	5.58	Table 1.6-1	Filterable $PM_{2.5}$ from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
PM	Condensible	--		8.50	0.017	Table 1.6-1	Condensible PM from wood residue combustion, bark and wet wood.
PM_{10}	Condensible	--		8.50	0.017	Table 1.6-1	Condensible PM from wood residue combustion, bark and wet wood.
$PM_{2.5}$	Condensible	--		8.50	0.017	Table 1.6-1	Condensible PM from wood residue combustion, bark and wet wood.
Lead		0.0007	Negligible	0.02	4.80E-05	Table 1.6-4	
NH_3		--		6.43	0.0129	Note 2 - Predicted 25 ppmv NH_3 slip. Includes NH_3 from gaseous fuel source.	
GHG Pollutants							
CO_2		3,150	1,195.93	107,789.44	215.54	Boiler fuel criteria engineering calculations - 100% conversion fuel carbon to CO_2.	
CH_4		--		35.29	0.071	CCAR Table C.8 (0.032 kg CH_4/MMBtu). Methane is a combustible boiler fuel.	
N_2O		--		4.63	0.009	CCAR Table C.8 (0.0042 kg N_2O/MMBtu).	

(1) Emission factors for CO in parts per million (ppm) converted to lb/MMBtu as follows:

EF (lb/MMBtu) = (ppm) x (k) x (F) x (20.9/(20.9-%O_2))

where:

CO =	260 ppm	Vendor Proposal
%O_2 =	3 %	
k =	unit conversion, (2.59E-09 x Molecular Weight (M)) lb/dscf = 1 ppm	
k (for CO) =	7.25E-08 (lb/scf)/ppm	
F =	9988.31 dscf/MMBtu	Based on stoichiometric flow
Molecular weight of CO =	28.01	

(2) Emission factors for NH_3 in parts per million (ppm) converted to lb/MMBtu as follows:

EF (lb/MMBtu) = (ppm) x (k) x (F) x (20.9/(20.9-%O_2))

where:

NH_3 =	25 ppm	Vendor Proposal
%O_2 =	3 %	
k =	unit conversion, (2.59E-09 x Molecular Weight (M)) lb/dscf = 1 ppm	
k (for NH_3) =	4.41077E-08 (lb/scf)/ppm	
F =	9988.31 dscf/MMBtu	Based on stoichiometric flow
Molecular weight of NH_3 =	17.03	

EP-20001
Biomass-Fired Stoker Boiler

Emissions: Maximum WORST CASE Fuel Blend		Control Efficiency	EP-20001 Biomass-Fired Stoker Boiler Uncontrolled		EP-20001 Biomass-Fired Stoker Boiler Controlled		BACT
Criteria Pollutants		(%)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/MMBtu)
NOx		45%	377.38	1,652.92	207.56	909.10	0.415
SO_2		92%	1,326.94	5,811.99	106.16	464.96	0.212
H_2SO_4 (SAM)		99%	81.23	355.79	0.81	3.56	0.002
CO		0%	110.04	481.99	110.04	481.99	0.220
VOC		70%	8.50	37.24	2.55	11.17	0.005
PM	Filterable	99.8%	3,635.05	15,921.54	7.27	31.84	0.015
PM_{10}	Filterable	99.8%	3,245.58	14,215.66	6.49	28.43	0.013
$PM_{2.5}$	Filterable	99.8%	2,791.20	12,225.47	5.58	24.45	0.011
PM	Condensible	0%	8.50	37.24	8.50	37.24	0.017
PM_{10}	Condensible	0%	8.50	37.24	8.50	37.24	0.017
$PM_{2.5}$	Condensible	0%	8.50	37.24	8.50	37.24	0.017
Lead		0%	0.02	0.11	0.02	0.11	--
NH_3		0%	--	--	0.00	0.00	--
GHG Pollutants							
CO_2		0%	107,789	472,118	107,789	472,118	--
CH_4		0%	35.29	154.55	35.29	154.55	--
N_2O		0%	4.63	20.29	4.63	20.29	--

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Biomass-Fired Stoker Boiler

Biomass-Fired Stoker Boiler Emissions (Solid Fuel Failure Fuel Blend)

Emission Factors: Solid Fuel Failure Fuel Blend [Liquid (i.e. EH Stillage Syrup) and Gaseous Fuels Only]		Combined Fuels (Excluding Natural Gas)	Process Vents	Total		
Criteria Pollutants		(lb/dry ton)	(lb/hr)	(lb/hr)	(lb/MMBtu)	Notes:
NOx		11.42	0.64	190.10	0.55	Predicted NOx for similar fuel combustion for stoker from vendor proposal (approximately 11% fuel N conversion to NOx) with use of low NOx technology. Staged combustion to minimize thermal NOx. Natural gas added into emission factor based on LNB emission rate.
SO_2		58.00	0.301	921.78	2.62	Predicted SOx for similar fuel combustion for stoker from vendor testing (100% fuel S conversion to SOx).
H_2SO_4 (SAM)		--		56.43	0.16	Based on 4% SO_2 conversion to SO_3 and 100% conversion SO_3 to H_2SO_4.
CO		4.20	Negligible	66.78	0.190	Note 1. Predicted CO for similar fuel combustion for stoker from vendor proposal. Modern combustion practices, staged combustion, fuel/air mixing, large firebox/residence time.
VOC		0.38	Negligible	5.98	0.017	Table 1.6-3, 70% control efficiency for use of modern stoker boiler based on performance test data from similar fuel combustion for stoker.
PM	Filterable	--		690.91	1.97	Table 1.6-1 Filterable PM from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
PM_{10}	Filterable	--		616.88	1.76	Table 1.6-1 Filterable PM_{10} from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
$PM_{2.5}$	Filterable	--		530.52	1.51	Table 1.6-1 Filterable $PM_{2.5}$ from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
PM	Condensible	--		5.98	0.017	Table 1.6-1 Condensible PM from wood residue combustion, bark and wet wood.
PM_{10}	Condensible	--		5.98	0.017	Table 1.6-1 Condensible PM from wood residue combustion, bark and wet wood.
$PM_{2.5}$	Condensible	--		5.98	0.017	Table 1.6-1 Condensible PM from wood residue combustion, bark and wet wood.
Lead		0.0011	Negligible	0.02	4.80E-05	Table 1.6-4
NH_3		--		4.00	0.0114	Note 2 - Predicted 25 ppmv NH_3 slip. Includes NH_3 from gaseous fuel source.
GHG Pollutants						
CO_2		3,366	1,195.93	54,673.26	155.54	Boiler fuel criteria engineering calculations - 100% conversion fuel carbon to CO_2.
CH_4		--		24.80	0.071	CCAR Table C.8 (0.032 kg CH_4/MMBtu). Methane is a combustible boiler fuel.
N_2O		--		3.26	0.009	CCAR Table C.8 (0.0042 kg N_2O/MMBtu).

(1) Emission factors for CO in parts per million (ppm) converted to lb/MMBtu as follows:

EF (lb/MMBtu) = (ppm) x (k) x (F) x (20.9/(20.9-%O_2))

where:

CO =	260 ppm	Vendor Proposal
%O_2 =	3 %	
k =	unit conversion, (2.59E-09 x Molecular Weight (M)) lb/dscf = 1 ppm	
k (for CO) =	7.25E-08 (lb/scf)/ppm	
F =	8838.72 dscf/MMBtu	Based on stoichiometric flow
Molecular weight of CO =	28	

(2) Emission factors for NH_3 in parts per million (ppm) converted to lb/MMBtu as follows:

EF (lb/MMBtu) = (ppm) x (k) x (F) x (20.9/(20.9-%O_2))

where:

NH_3 =	25 ppm	Vendor Proposal
%O_2 =	3 %	
k =	unit conversion, (2.59E-09 x Molecular Weight (M)) lb/dscf = 1 ppm	
k (for NH_3) =	4.41077E-08 (lb/scf)/ppm	
F =	8838.72 dscf/MMBtu	Based on stoichiometric flow
Molecular weight of NH_3 =	17.03	

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Biomass-Fired Stoker Boiler

Emissions: Solid Fuel Failure Fuel Blend [Liquid (i.e. EH Stillage Syrup) and Gaseous Fuels Only]		Control Efficiency	EP-20001 Biomass-Fired Stoker Boiler Uncontrolled		EP-20001 Biomass-Fired Stoker Boiler Controlled		BACT
Criteria Pollutants		(%)	(lb/hr)	(ton/yr)	(lb/hr)	(ton/yr)	(lb/MMBtu)
NOx		45%	190.10	832.63	104.55	457.94	0.297
SO_2		92%	921.78	4,037.38	73.74	322.99	0.210
H_2SO_4 (SAM)		99%	56.43	247.16	0.56	2.47	0.002
CO		0%	66.78	292.52	66.78	292.52	0.190
VOC		70%	5.98	26.17	1.79	7.85	0.005
PM	Filterable	99.3%	690.91	3,026.17	4.84	21.18	0.014
PM_{10}	Filterable	99.3%	616.88	2,701.94	4.32	18.91	0.012
$PM_{2.5}$	Filterable	99.3%	530.52	2,323.66	3.71	16.27	0.011
PM	Condensible	0%	5.98	26.17	5.98	26.17	0.017
PM_{10}	Condensible	0%	5.98	26.17	5.98	26.17	0.017
$PM_{2.5}$	Condensible	0%	5.98	26.17	5.98	26.17	0.017
Lead		0%	0.02	0.07	0.02	0.07	--
NH_3		0%	--	--	5.69	24.93	--
GHG Pollutants							
CO_2		0%	54,673	239,469	54,673	239,469	--
CH_4		0%	24.80	108.63	24.80	108.63	--
N_2O		0%	3.26	14.26	3.26	14.26	--

EP-20001
Biomass-Fired Stoker Boiler

HAPs Emissions from Combustion in Area 20000 (Maximum WORST CASE Fuel Blend)

Basis: AP-42 Section 1.6 Wood Residue Combustion in Boilers, Final Section, September 2003.

Speciated HAP emission factors typically based on the "Average Emission Factor" for dutch oven, stoker and fluidized bed combustion boilers as provided in AP-42 unless otherwise noted.

Control of acetaldehyde, acrolein, benzene, formaldehyde, naphthalene, styrene and toluene assumed 70% reduction for modern staged combustion stoker and good combustion practices (based on performance test data from similar fuel combustion for stoker). Particulate HAPs (metals) AP-42 emission factors are for boilers with no controls or with particulate matter controls; therefore, no additional control for the baghouse was applied.

Hydrogen chloride emission factor based on the worst case assumptions that 100% of fuel chlorine becomes hydrogen chloride and control efficiency obtained from vendor specifications. A factor of safety of 1.5 has been applied to the emission factor to account for variability in the fuel chlorine concentrations.

Hydrogen fluoride emissions based on the data contained in the Speciated metal HAP emission factors obtained from the EPA's Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reported Under ICR No. 2286.01 and ICR No. 2286.03 (Version 6).mdb dated February 2011. Values for biomass stoker or sloped grate boilers assumed similar to the proposed biomass-fired stoker boiler. Value based on the maximum concentration reported when biomass was 90% of the fuel combusted or greater. This value is slightly higher than the overall test average of all HF emissions for biomass stoker or sloped grate boilers reported.

Control options of hydrogen chloride and hydrogen fluoride are essentially the same as for other acid gases and particulate matter emissions. The proposed control for acid gases and particulate matter are BACT, which will provide a consistently achievable 99% control efficiency for hydrogen chloride and hydrogen fluoride emissions.

Total Hexachlorodibenzo-p-dioxins (HxCDDs) emission factor adjusted in accordance with North Carolina Department of Environment and Natural Resources, Division of Air Quality, June 11, 2008 Memorandum: Emission Factors for Wood-Fired Industrial Boilers for 1,2,3,6,7,8-HxCDD.
Only factors for pollutants noted as HAPs as defined by Section 112(b) of the Clean Air Act listed.

Criteria:

Annual Operations	8,760 hr/yr
Boiler Heat Input	500 MMBtu/hr

Pollutant	Emission Factor (lb/MMBtu)	Control Efficiency (%)	EP-20001 Biomass-Fired Stoker Boiler Uncontrolled (lb/hr)	(ton/yr)	EP-20001 Biomass-Fired Stoker Boiler Controlled (lb/hr)	(ton/yr)	Controlled Emission Rate (lb/MMBtu)
Total HAPs	—	—	**138.80**	**607.93**	**4.20**	**18.41**	—
Acetaldehyde	8.30E-04	70%	0.42	1.82	0.12	0.55	2.49E-04
Acrolein	4.00E-03	70%	2.00	8.76	0.60	2.63	1.20E-03
Benzene	4.20E-03	70%	2.10	9.20	0.63	2.76	1.26E-03
Formaldehyde	4.40E-03	70%	2.20	9.64	0.66	2.89	1.32E-03
Naphthalene	9.70E-05	70%	0.05	0.21	0.01	0.06	2.91E-05
Styrene	1.90E-03	70%	0.95	4.16	0.29	1.25	5.70E-04
Toluene	9.20E-04	70%	0.46	2.02	0.14	0.60	2.76E-04
Chlorine	Assumes 100% fuel chlorine becomes hydrogen chloride for worst-case scenario.						
Hydrogen chloride	2.60E-01	99%	130.02	569.50	1.30	5.70	0.003
Hydrogen fluoride	3.00E-04	99%	0.15	0.66	0.00	0.01	3.00E-06

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Biomass-Fired Stoker Boiler

Pollutant	Emission Factor (lb/MMBtu)	Control Efficiency (%)	EP-20001 Biomass-Fired Stoker Boiler Uncontrolled (lb/hr)	EP-20001 Biomass-Fired Stoker Boiler Uncontrolled (ton/yr)	EP-20001 Biomass-Fired Stoker Boiler Controlled (lb/hr)	EP-20001 Biomass-Fired Stoker Boiler Controlled (ton/yr)	Notes
Metals:			0.04	0.19	0.04	0.19	
Antimony	1.58E-06	0%	7.90E-04	3.46E-03	7.90E-04	3.46E-03	Note 1
Arsenic	1.58E-05	0%	7.90E-03	3.46E-02	7.90E-03	3.46E-02	Note 1
Beryllium	1.17E-05	0%	5.85E-03	2.56E-02	5.85E-03	2.56E-02	Note 1
Cadmium	2.62E-08	0%	1.31E-05	5.73E-05	1.31E-05	5.73E-05	Note 2
Chromium, total	2.62E-07	0%	1.31E-04	5.73E-04	1.31E-04	5.73E-04	Note 3
Chromium, hexavalent	5.24E-08	0%	2.62E-05	1.15E-04	2.62E-05	1.15E-04	Note 3
Cobalt	8.07E-08	0%	4.04E-05	1.77E-04	4.04E-05	1.77E-04	Note 4
Lead	4.80E-05	0%	2.40E-02	1.05E-01	2.40E-02	1.05E-01	Table 1.6-4
Manganese	8.94E-06	0%	4.47E-03	1.96E-02	4.47E-03	1.96E-02	Note 5
Mercury	8.73E-09	0%	4.36E-06	1.91E-05	4.36E-06	1.91E-05	Note 6
Nickel	5.24E-07	0%	2.62E-04	1.15E-03	2.62E-04	1.15E-03	Note 7
Selenium	3.27E-08	0%	1.64E-05	7.17E-05	1.64E-05	7.17E-05	Note 8

(1) Speciated metal HAP emission factors obtained from the EPA's Emissions Database for Boilers and Process Heaters Containing Stack Test, CEM, & Fuel Analysis Data Reported Under ICR No. 2286.01 and ICR No. 2286.03 (Version 6).mdb dated February 2011. Values for biomass stoker or sloped grate boilers assumed similar to the proposed biomass-fired stoker boiler. Non detect values included in the average.

(2) Based on trace metal analysis of corn stover = 0.12 mg/L Cd concentrated in cake/syrup + 100% safety margin.

(3) Based on trace metal analysis of corn stover = 1.2 mg/L Cr concentrated in cake/syrup + 100% safety margin. Hexavalent chromium assumed to be approximately 20% of total chromium.

(4) Based on trace metal analysis of corn stover = 0.37mg/L Co concentrated in cake/syrup + 100% safety margin.

(5) Based on trace metal analysis of corn stover = 41 mg/L Mn concentrated in cake/syrup + 100% safety margin.

(6) Based on trace metal analysis of corn stover = 0.04 mg/L Hg concentrated in cake/syrup + 100% safety margin.

(7) Based on trace metal analysis of corn stover = 2.4 mg/L Ni concentrated in cake/syrup + 100% safety margin

(8) Based on trace metal analysis of corn stover = 1.5 mg/L Se concentrated in cake/syrup + 100% safety margin

Pollutant	Emission Factor (lb/MMBtu)	Control Efficiency (%)	EP-20001 Biomass-Fired Stoker Boiler Uncontrolled (lb/hr)	EP-20001 Biomass-Fired Stoker Boiler Uncontrolled (ton/yr)	EP-20001 Biomass-Fired Stoker Boiler Controlled (lb/hr)	EP-20001 Biomass-Fired Stoker Boiler Controlled (ton/yr)
Minor HAPs:			0.39	1.71	0.39	1.71
Acetophenone	3.20E-09	0%	1.60E-06	7.01E-06	1.60E-06	7.01E-06
Benzoic acid (chloramben)	4.70E-08	0%	2.35E-05	1.03E-04	2.35E-05	1.03E-04
bis(2-Ethylhexyl)phthalate (DEHP)	4.70E-08	0%	2.35E-05	1.03E-04	2.35E-05	1.03E-04
Bromomethane (methl bromide)	1.50E-05	0%	7.50E-03	3.29E-02	7.50E-03	3.29E-02
Carbon tetrachloride	4.50E-05	0%	2.25E-02	9.86E-02	2.25E-02	9.86E-02
Chlorobenzene	3.30E-05	0%	1.65E-02	7.23E-02	1.65E-02	7.23E-02
Chloroform	2.80E-05	0%	1.40E-02	6.13E-02	1.40E-02	6.13E-02
Chloromethane (methyl chloride)	2.30E-05	0%	1.15E-02	5.04E-02	1.15E-02	5.04E-02
1,2-Dichloroethane (ethylene dichloride)	2.90E-05	0%	1.45E-02	6.35E-02	1.45E-02	6.35E-02
1,2-Dichloropropane (propylene dichloride)	3.30E-05	0%	1.65E-02	7.23E-02	1.65E-02	7.23E-02
2,4-Dinitrophenol	1.80E-07	0%	9.00E-05	3.94E-04	9.00E-05	3.94E-04
Dichloromethane (methylene chloride)	2.90E-04	0%	1.45E-01	6.35E-01	1.45E-01	6.35E-01
Ethylbenzene	3.10E-05	0%	1.55E-02	6.79E-02	1.55E-02	6.79E-02
Pentachlorophenol	5.10E-08	0%	2.55E-05	1.12E-04	2.55E-05	1.12E-04
4-Nitrophenol	1.10E-07	0%	5.50E-05	2.41E-04	5.50E-05	2.41E-04
Phenol	5.10E-05	0%	2.55E-02	1.12E-01	2.55E-02	1.12E-01
Propionaldehyde	6.10E-05	0%	3.05E-02	1.34E-01	3.05E-02	1.34E-01
Tetrachloroethene	3.80E-05	0%	1.90E-02	8.32E-02	1.90E-02	8.32E-02
1,1,1-Trichloroethane (methyl chloroform)	3.10E-05	0%	1.55E-02	6.79E-02	1.55E-02	6.79E-02
Trichloroethene	3.00E-05	0%	1.50E-02	6.57E-02	1.50E-02	6.57E-02
2,4,6-Trichlorophenol	2.20E-08	0%	1.10E-05	4.82E-05	1.10E-05	4.82E-05
Vinyl chloride	1.80E-05	0%	9.00E-03	3.94E-02	9.00E-03	3.94E-02
o-Xylene	2.50E-05	0%	1.25E-02	5.48E-02	1.25E-02	5.48E-02

EP-20001
Biomass-Fired Stoker Boiler

Pollutant	Emission Factor (lb/MMBtu)	EP-20001 Biomass-Fired Stoker Boiler Uncontrolled (lb/hr)	(ton/yr)	EP-20001 Biomass-Fired Stoker Boiler Controlled (lb/hr)	(ton/yr)
Polychlorinated biphenyls:		3.96E-06	1.74E-05	3.96E-06	1.74E-05
Decachlorobiphenyl	2.70E-10	1.35E-07	5.91E-07	1.35E-07	5.91E-07
Dichlorobiphenyl	7.40E-10	3.70E-07	1.62E-06	3.70E-07	1.62E-06
Heptachlorobiphenyl	6.60E-11	3.30E-08	1.45E-07	3.30E-08	1.45E-07
Hexachlorobiphenyl	5.50E-10	2.75E-07	1.20E-06	2.75E-07	1.20E-06
Pentachlorobiphenyl	1.20E-09	6.00E-07	2.63E-06	6.00E-07	2.63E-06
Trichlorobiphenyl	2.60E-09	1.30E-06	5.70E-06	1.30E-06	5.70E-06
Tetrachlorobiphenyl	2.50E-09	1.25E-06	5.48E-06	1.25E-06	5.48E-06

Pollutant	Emission Factor (lb/MMBtu)	EP-20001 Biomass-Fired Stoker Boiler Uncontrolled (lb/hr)	(ton/yr)	EP-20001 Biomass-Fired Stoker Boiler Controlled (lb/hr)	(ton/yr)
Polycyclic Organic Matter:		1.40E-02	6.13E-02	1.40E-02	6.13E-02
Benzo(a)anthracene	6.50E-08	3.25E-05	1.42E-04	3.25E-05	1.42E-04
Benzo(a)pyrene	2.60E-06	1.30E-03	5.70E-03	1.30E-03	5.70E-03
Benzo(b)fluoranthene	1.00E-07	5.00E-05	2.19E-04	5.00E-05	2.19E-04
Benzo(e)pyrene	2.60E-09	1.30E-06	5.70E-06	1.30E-06	5.70E-06
Benzo(g,h,i)perylene	9.30E-08	4.65E-05	2.04E-04	4.65E-05	2.04E-04
Benzo(j,k)fluoranthene	1.60E-07	8.00E-05	3.50E-04	8.00E-05	3.50E-04
Benzo(k)fluoranthene	3.60E-08	1.80E-05	7.89E-05	1.80E-05	7.89E-05
Chrysene	3.80E-08	1.90E-05	8.32E-05	1.90E-05	8.32E-05
Dibenzo(a,h)anthracene	9.10E-09	4.55E-06	1.99E-05	4.55E-06	1.99E-05
Indeno(1,2,3,c,d)pyrene	8.70E-08	4.35E-05	1.91E-04	4.35E-05	1.91E-04
Acenaphthene	9.10E-07	4.55E-04	1.99E-03	4.55E-04	1.99E-03
Fluorene	3.40E-06	1.70E-03	7.45E-03	1.70E-03	7.45E-03
Anthracene	3.00E-06	1.50E-03	6.57E-03	1.50E-03	6.57E-03
Phenanthrene	7.00E-06	3.50E-03	1.53E-02	3.50E-03	1.53E-02
Fluoranthene	1.60E-06	8.00E-04	3.50E-03	8.00E-04	3.50E-03
Pyrene	3.70E-06	1.85E-03	8.10E-03	1.85E-03	8.10E-03
Perylene	5.20E-10	2.60E-07	1.14E-06	2.60E-07	1.14E-06
Acenaphthylene	5.00E-06	2.50E-03	1.10E-02	2.50E-03	1.10E-02
2-Methylnaphthalene	1.60E-07	8.00E-05	3.50E-04	8.00E-05	3.50E-04
2-Chloronaphthalene	2.40E-09	1.20E-06	5.26E-06	1.20E-06	5.26E-06

Pollutant	Emission Factor (lb/MMBtu)	Toxic Equivalency Factor (TEF)	Toxic Equivalents (TEQ) EP-20001 Biomass-Fired Stoker Boiler Uncontrolled (lb/hr)	(ton/yr)	Toxic Equivalents (TEQ) EP-20001 Biomass-Fired Stoker Boiler Controlled (lb/hr)	(ton/yr)
Dibenzo furans:			4.19E-08	1.83E-07	4.19E-08	1.83E-07
Heptachlorodibenzo-p-furans	2.40E-10	0	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Hexachlorodibenzo-p-furans	2.80E-10	0	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Octachlorodibenzo-p-furans	8.80E-11	0.001	4.40E-11	1.93E-10	4.40E-11	1.93E-10
Pentachlorodibenzo-p-furans	4.20E-10	0	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2,3,7,8-Tetrachlorodibenzo-p-furans	9.00E-11	0.1	4.50E-09	1.97E-08	4.50E-09	1.97E-08
Tetrachlorodibenzo-p-furans	7.50E-10	0	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Dioxins:						
Heptachlorodibenzo-p-dioxins	2.00E-09	0	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Hexachlorodibenzo-p-dioxins	3.19E-11	0	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Octachlorodibenzo-p-dioxins	6.60E-08	0.001	3.30E-08	1.45E-07	3.30E-08	1.45E-07
Pentachlorodibenzo-p-dioxins	1.50E-09	0	0.00E+00	0.00E+00	0.00E+00	0.00E+00
2,3,7,8-Tetrachlorodibenzo-p-dioxins	8.60E-12	1.0	4.30E-09	1.88E-08	4.30E-09	1.88E-08
Tetrachlorodibenzo-p-dioxins	4.70E-10	0	0.00E+00	0.00E+00	0.00E+00	0.00E+00

EP-20001
Biomass-Fired Stoker Boiler During Start-Up and at Reduced Loads

Fuel Configuration

Basis:

Emissions from biomass combustion presented for a stoker boiler during normal operations are still applicable.

In addition to firing biomass and biogas, the biomass-fired stoker boiler will be capable of firing on natural gas during normal operations as needed, as well as firing on a combination of natural gas, liquid fuel (i.e. EH stillage syrup) and biogas in the event of a solid fuel failure. "Start-up" emissions are based on the combustion of natural gas only, without any add-on control devices. All other firing scenarios will only be possible when the add-on control devices are operational.

Biomass-fired stoker boiler start-up based on the use of natural gas to heat the boiler to 400 °C (approximately 4 hours). The spray dry absorber (SDA) scrubber and SNCR are started when the appropriate operating temperature is achieved. No fuels other than natural gas will be combusted until the SDA scrubber is operational. The SNCR will be fully functional at greater than 30% load. The baghouse utilized for PM control will be in service at all times.

Gaseous fuel to be supplied to the biomass-fired stoker boiler from the wastewater treatment system will not be feed to the boiler system during SSM.

AP-42 Section 1.4 Natural Gas Combustion, Final Section, July 1998.

California Climate Action Registry (CCAR) General Reporting Protocol, Version 3.1, January 2009.

Criteria:

Number of Solids-Fired Boilers	1	
Total Area 20000 Heat Input - Permit	500 MMBtu/hr	
Maximum Heat Input Per Boiler When Fully Operational	500 MMBtu/hr	
Heat Input During Initial Start-up	61 MMBtu/hr	Natural gas used for start-up.
30% of Nominal Heat Input When Fully Operational	141 MMBtu/hr	Approximately 30% Load of Nominal Design (Baghouse and SDA Scrubber Operational, no SNCR).
50% of Nominal Heat Input When Fully Operational	236 MMBtu/hr	Approximately 50% Load of Nominal Design (Baghouse and SDA Scrubber Operational, SNCR).
75% of Nominal Heat Input When Fully Operational	353 MMBtu/hr	Approximately 75% Load of Nominal Design (Baghouse, Scrubber and SNCR Operational).
100% of Nominal Heat Input When Fully Operational	471 MMBtu/hr	100% Load of Nominal Design, Approximately 83.5% Load of Boiler Nameplate.
Annual Operations	8,760 hr/yr	

Source Details:

	Stack Flow Rate	Stack Diameter	Release Height	Stack Area	Gas Velocity		Gas Exit Temperature	
Percent Load	(cfm)	(in)	(ft)	(ft^2)	(ft/s)	(m/s)	(deg F)	(deg K)
30% Reduced Load	66,000	120	160	78.54	14.01	4.27	250	394
50% Reduced Load	110,000	120	160	78.54	23.34	7.11	280	411
75% of Nominal Design Load	165,000	120	160	78.54	35.01	10.67	300	422
100% of Nominal Design Load	220,000	120	160	78.54	46.69	14.23	300	422
120% of Nominal Design Load	264,000	120	160	78.54	56.02	17.07	300	422

EP-20001
Biomass-Fired Stoker Boiler During Start-Up and at Reduced Loads

Biomass-Fired Boiler Emissions (Maximum WORST CASE Fuel Blend)

Emission Factors: (Maximum WORST CASE Fuel Blend)		Combined Fuels	Process Vents	Total		Notes:	
Criteria Pollutants		(lb/dry ton)	(lb/hr)	(lb/hr)	(lb/MMBtu)		
NOx		11.13	0.64	377.38	0.76	Predicted NOx for similar fuel combustion for stoker from vendor proposal (approximately 11% fuel N conversion to NOx). Staged combustion to minimize thermal NOx.	
SO_2		39.20	0.301	1326.94	2.65	Predicted SOx for similar fuel combustion for stoker from vendor testing (100% fuel S conversion to SOx).	
CO		3.25	Negligible	110.04	0.22	Note 1. Predicted CO for similar fuel combustion for stoker from vendor proposal. Modern combustion practices, staged combustion, fuel/air mixing, large firebox/residence time.	
VOC		0.25	Negligible	8.50	0.017	fuel combustion for stoker.	
PM	Filterable	--		3,635.05	7.27	Table 1.6-1	Filterable PM from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
PM_{10}	Filterable	--		3,245.58	6.49	Table 1.6-1	Filterable PM_{10} from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
$PM_{2.5}$	Filterable	--		2,791.20	5.58	Table 1.6-1	Filterable $PM_{2.5}$ from wood residue combustion, bark and wet wood. Adjusted to account for increased ash content of fuel blend.
PM	Condensible	--		8.50	0.017	Table 1.6-1	Condensible PM from wood residue combustion, bark and wet wood.
PM_{10}	Condensible	--		8.50	0.017	Table 1.6-1	Condensible PM from wood residue combustion, bark and wet wood.
$PM_{2.5}$	Condensible	--		8.50	0.017	Table 1.6-1	Condensible PM from wood residue combustion, bark and wet wood.
Lead		0.0007	Negligible	0.02	4.80E-05	Table 1.6-4	
NH_3		--		6.43	0.0129	Note 2 - Predicted 25 ppmv NH_3 slip. Includes NH_3 from gaseous fuel source.	
GHG Pollutants							
CO_2		3,150	1,195.93	107,789.44	215.54	Boiler fuel criteria engineering calculations - 100% conversion fuel carbon to CO_2.	
CH_4		--		35.29	0.071	CCAR Table C.8 (0.032 kg CH_4/MMBtu). Methane is a combustible boiler fuel.	
N_2O		--		4.63	0.009	CCAR Table C.8 (0.0042 kg N_2O/MMBtu).	

EP-20001
Biomass-Fired Stoker Boiler During Start-Up and at Reduced Loads

Natural Gas Emission Factors:						
Criteria Pollutants		EF	Unit	EF	Unit	Notes:
NOx		190	lb/MMscf	0.04	lb/MMBtu	Note 1 - Maximum BACT Low-NOx Burner (LNB) = 0.04 MMBtu/hr (or 30 ppm @ 3% Oxygen)
SO_2		0.6	lb/MMscf	5.88E-04	lb/MMBtu	Table 1.4-2
CO		84	lb/MMscf	0.04	lb/MMBtu	Note 1 - Maximum BACT for CO with Good Combustion Practices = 0.04 MMBtu/hr (or 50 ppm @ 3% Oxygen)
VOC		5.5	lb/MMscf	5.39E-03	lb/MMBtu	Table 1.4-2
$PM/PM_{10}/PM_{2.5}$	Filterable	1.9	lb/MMscf	1.86E-03	lb/MMBtu	Table 1.4-2 All PM is assumed to be less than 1.0 micrometer in diameter.
$PM/PM_{10}/PM_{2.5}$	Condensible	5.7	lb/MMscf	5.59E-03	lb/MMBtu	Table 1.4-2 All PM is assumed to be less than 1.0 micrometer in diameter.
Lead		0.0005	lb/MMscf	4.90E-07	lb/MMBtu	Table 1.4-2
GHG Pollutants						
Natural Gas CO_2		119,337.25	lb/MMscf	117.00	lb/MMBtu	CCAR Table C.7 (53.06 kg CO_2/MMBtu, 100% Oxidization)
CH_4		2.2491	lb/MMscf	0.002205	lb/MMBtu	CCAR Table C.8 (0.001 kg CH_4/MMBtu)
N_2O		0.22491	lb/MMscf	0.0002205	lb/MMBtu	CCAR Table C.8 (0.0001 kg N_2O/MMBtu)

(1) Vendor emission factors for natural gas NO_x and CO emissions in parts per million (ppm) converted to lb/MMBtu as follows:

NOx EF (lb/MMBtu) = (ppm) x (k) x (F) x (20.9-(20.9-%O_2))

Where:

NO_x =	30	ppm
CO =	50	ppm
%O_2 =	3	%
k =	unit conversion, (2.59E-09 x M) lb/dscf = 1 ppm	
k (for NO_2) =	1.19E-07	(lb/scf)/ppm
k (for CO) =	7.25E-08	(lb/scf)/ppm
F =	8710	dscf/MMBtu
Molecular weight of NO_x as NO_2 =	46	
Molecular weight of CO =	28	

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Biomass-Fired Stoker Boiler During Start-Up and at Reduced Loads

Emissions: Worst Case Emissions During Start-up and at Reduced Loads		Control Efficiency	Fully Operational Biomass-Fired Stoker Boiler Controlled	**Boiler During Initial Start-up Burning Natural Gas Only**	**Operating at 30% Reduced Nominal Load (Baghouse and Scrubber Operational, no SNCR)**	**Operating at 50% Reduced Nominal Load (Baghouse and Scrubber and SNCR Operational)**	**Operating at 75% Reduced Nominal Load (Baghouse, Scrubber and SNCR Operational)**	**Boiler Operating at 100% Nominal Load (Baghouse, Scrubber and SNCR Operational)**
Criteria Pollutants		(%)	(lb/hr)	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**
NOx		45%	207.56	**2.44**	**107.39**	**98.44**	**147.66**	**196.88**
SO_2		92%	106.16	**0.04**	**29.99**	**49.99**	**74.99**	**99.98**
CO		0%	110.04	**2.44**	**31.09**	**51.81**	**77.72**	**103.62**
VOC		70%	2.55	**0.33**	**0.72**	**1.20**	**1.80**	**2.40**
PM	Filterable	99.8%	7.27	**0.11**	**2.05**	**3.42**	**5.14**	**6.85**
PM_{10}	Filterable	99.8%	6.49	**0.11**	**1.83**	**3.06**	**4.59**	**6.11**
$PM_{2.5}$	Filterable	99.8%	5.58	**0.11**	**1.58**	**2.63**	**3.94**	**5.26**
PM	Condensible	0%	8.50	**0.34**	**2.40**	**4.00**	**6.01**	**8.01**
PM_{10}	Condensible	0%	8.50	**0.34**	**2.40**	**4.00**	**6.01**	**8.01**
$PM_{2.5}$	Condensible	0%	8.50	**0.34**	**2.40**	**4.00**	**6.01**	**8.01**
Lead		0%	0.02	**0.00**	**0.007**	**0.011**	**0.017**	**0.023**
NH_3		0%	--	**--**	**--**	**3.03**	**4.54**	**6.06**
GHG Pollutants								
Natural Gas CO_2		0%	107,789	**0.13**	**16,532**	**50,760**	**76,140**	**101,519**
CH_4		0%	35.29	**0.01**	**0.31**	**16.62**	**24.93**	**33.23**
N_2O		0%	4.63	**0.00**	**0.03**	**2.18**	**3.27**	**4.36**

EP-20001
Biomass-Fired FBC Boiler During Start-Up and at Reduced Loads

HAPs Emissions from Combustion in Area 20000

Basis: Emissions from biomass combustion presented for FBC boilers during normal operations are still applicable.

Biomass-fired stoker boiler start-up based on the use of natural gas to heat the boiler to 400 °C (approximately 4 hours). The spray dry absorber (SDA) scrubber and SNCR are started when the appropriate operating temperature is achieved. No fuels other than natural gas will be combusted until the SDA scrubber is operational. The SNCR will be fully functional at greater than 30% load. The baghouse utilized for PM control will be in service at all times.
Gaseous fuel to be supplied to the biomass-fired stoker boiler from the wastewater treatment system will not be feed to the boiler system during SSM.
AP-42 Section 1.4 Natural Gas Combustion, Final Section, July 1998.

Criteria:

Number of Solids-Fired Boilers	1	
Total Area 20000 Heat Input - Permit	500 MMBtu/hr	
Maximum Heat Input Per Boiler When Fully Operational	500 MMBtu/hr	
Heat Input During Initial Start-up	61 MMBtu/hr	Natural gas used for start-up.
30% of Nominal Heat Input When Fully Operational	141 MMBtu/hr	Approximately 30% Load of Nominal Design (Baghouse and SDA Scrubber Operational, no SNCR).
50% of Nominal Heat Input When Fully Operational	236 MMBtu/hr	Approximately 50% Load of Nominal Design (Baghouse and SDA Scrubber Operational, SNCR).
75% of Nominal Heat Input When Fully Operational	353 MMBtu/hr	Approximately 75% Load of Nominal Design (Baghouse, Scrubber and SNCR Operational).
100% of Nominal Heat Input When Fully Operational	471 MMBtu/hr	100% Load of Nominal Design, Approximately 83.5% Load of Boiler Nameplate.
Annual Operations	8,760 hr/yr	

UNCONTROLLED	Biomass Emission Factor	Natural Gas Emission Factor	Control Efficiency	Fully Operational Biomass-Fired Stoker Boiler Controlled	Boiler During Initial Start-up Burning Natural Gas Only	Boiler Operating at 30% Reduced Nominal Load (Baghouse and Scrubber Operational, no SNCR)	Boiler Operating at 50% Reduced Nominal Load (Baghouse and Scrubber and SNCR Operational)	Boiler Operating at 75% Reduced Nominal Load (Baghouse, Scrubber and SNCR Operational)	Boiler Operating at 100% Nominal Load (Baghouse, Scrubber and SNCR Operational)
Pollutant	(lb/MMBtu)	(lb/MMBtu)	(%)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
Total HAPs	–	–	–	**4.20**	**0.11**	**39.17**	**65.29**	**97.94**	**130.58**
Acetaldehyde	8.30E-04	0	0%	0.12	0	1.17E-01	1.95E-01	0.293	0.391
Acrolein	4.00E-03	0	0%	0.60	0	5.65E-01	9.42E-01	1.413	1.884
Benzene	4.20E-03	2.06E-06	0%	0.63	1.26E-04	5.93E-01	9.89E-01	1.484	1.978
Formaldehyde	4.40E-03	7.35E-05	0%	0.66	4.49E-03	6.22E-01	1.04E+00	1.554	2.072
Hexane	0	1.76E-03	0%	0.01	1.08E-01	0.00E+00	0.00E+00	0.000	0.000
Naphthalene	9.70E-05	5.95E-08	0%	0.29	3.63E-06	1.37E-02	2.28E-02	0.034	0.046
Styrene	1.90E-03	0	0%	0.14	0	2.68E-01	4.47E-01	0.671	0.895
Toluene	9.20E-04	3.33E-06	0%	0.00	2.03E-04	1.30E-01	2.17E-01	0.325	0.433
Chlorine	Assumes 100% fuel chlorine becomes hydrogen chloride for worst-case scenario.								
Hydrogen chloride	2.60E-01	0	0%	1.30	0	3.67E+01	6.12E+01	91.845	122.460
Hydrogen flouride	6.50E-08	0	0%	0.00	0	9.18E-06	1.53E-05	2.30E-05	3.06E-05

EP-20001
Biomass-Fired FBC Boiler During Start-Up and at Reduced Loads

CONTROLLED	Biomass Emission Factor	Natural Gas Emission Factor	Control Efficiency	Fully Operational Biomass-Fired Stoker Boiler Controlled	Boiler During Initial Start-up Burning Natural Gas Only	Boiler Operating at 30% Reduced Nominal Load (Baghouse and Scrubber Operational, no SNCR)	Boiler Operating at 50% Reduced Nominal Load (Baghouse and Scrubber and SNCR Operational)	Boiler Operating at 75% Reduced Nominal Load (Baghouse, Scrubber and SNCR Operational)	Boiler Operating at 100% Nominal Load (Baghouse, Scrubber and SNCR Operational)
Pollutant	(lb/MMBtu)	(lb/MMBtu)	(%)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
Total HAPs	--	--	--	**4.20**	**0.11**	**1.19**	**1.98**	**2.97**	**3.96**
Acetaldehyde	8.30E-04	0	70%	0.12	0	3.52E-02	5.86E-02	0.088	0.117
Acrolein	4.00E-03	0	70%	0.60	0	1.70E-01	2.83E-01	0.424	0.565
Benzene	4.20E-03	2.06E-06	70%	0.63	1.26E-04	1.78E-01	2.97E-01	0.445	0.593
Formaldehyde	4.40E-03	7.35E-05	70%	0.66	4.49E-03	1.87E-01	3.11E-01	0.466	0.622
Hexane	0	1.76E-03	0%	0.01	1.08E-01	0.00E+00	0.00E+00	0.000	0.000
Naphthalene	9.70E-05	5.95E-08	70%	0.29	3.63E-06	4.11E-03	6.85E-03	0.010	0.014
Styrene	1.90E-03	0	70%	0.14	0	8.05E-02	1.34E-01	0.201	0.268
Toluene	9.20E-04	3.33E-06	70%	0.00	2.03E-04	3.90E-02	6.50E-02	0.097	0.130
Chlorine	Assumes 100% fuel chlorine becomes hydrogen chloride for worst-case scenario.								
Hydrogen chloride	2.60E-01	0	99%	1.30	0	3.67E-01	6.12E-01	0.918	1.225
Hydrogen flouride	6.50E-08	0	99%	0.00	0	9.18E-08	1.53E-07	2.30E-07	3.06E-07

	Biomass Emission Factor	Natural Gas Emission Factor	Control Efficiency	Fully Operational Biomass-Fired Stoker Boiler Controlled	Boiler During Initial Start-up Burning Natural Gas Only	Boiler Operating at 30% Reduced Nominal Load (Baghouse and Scrubber Operational, no SNCR)	Boiler Operating at 50% Reduced Nominal Load (Baghouse and Scrubber and SNCR Operational)	Boiler Operating at 75% Reduced Nominal Load (Baghouse, Scrubber and SNCR Operational)	Boiler Operating at 100% Nominal Load (Baghouse, Scrubber and SNCR Operational)
Pollutant	(lb/MMBtu)	(lb/MMBtu)	(%)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
Metals:				0.04	2.47E-04	1.23E-02	2.05E-02	3.07E-02	4.10E-02
Antimony	1.58E-06	0	0%	7.90E-04	0	2.23E-04	3.72E-04	5.58E-04	7.44E-04
Arsenic	1.58E-05	1.96E-07	0%	7.90E-03	1.20E-05	2.23E-03	3.72E-03	5.58E-03	7.44E-03
Beryllium	1.17E-05	0	0%	5.85E-03	0	1.65E-03	2.76E-03	4.13E-03	5.51E-03
Cadmium	2.62E-08	1.08E-06	0%	1.31E-05	6.58E-05	3.70E-06	6.17E-06	9.25E-06	1.23E-05
Chromium, total	2.62E-07	0	0%	1.31E-04	0	3.70E-05	6.17E-05	9.25E-05	1.23E-04
Chromium, hexavalent	5.24E-08	0	0%	2.62E-05	0	7.40E-06	1.23E-05	1.85E-05	2.47E-05
Cobalt	8.07E-08	8.24E-08	0%	4.04E-05	5.02E-06	1.14E-05	1.90E-05	2.85E-05	3.80E-05
Lead	4.80E-05	0.00E+00	0%	2.40E-02	0	6.78E-03	1.13E-02	1.70E-02	2.26E-02
Manganese	8.94E-06	3.73E-07	0%	4.47E-03	2.27E-05	1.26E-03	2.11E-03	3.16E-03	4.21E-03
Mercury	8.73E-09	2.55E-07	0%	4.36E-06	1.55E-05	1.23E-06	2.06E-06	3.08E-06	4.11E-06
Nickel	5.24E-07	2.06E-06	0%	2.62E-04	1.26E-04	7.40E-05	1.23E-04	1.85E-04	2.47E-04
Selenium	3.27E-08	0	0%	1.64E-05	0	4.62E-06	7.71E-06	1.16E-05	1.54E-05

EP-20001
Biomass-Fired FBC Boiler During Start-Up and at Reduced Loads

Pollutant	Biomass Emission Factor (lb/MMBtu)	Natural Gas Emission Factor (lb/MMBtu)	Control Efficiency (%)	Fully Operational Biomass-Fired Stoker Boiler Controlled (lb/hr)	Boiler During Initial Start-up Burning Natural Gas Only (lb/hr)	Boiler Operating at 30% Reduced Nominal Load (Baghouse and Scrubber Operational, no SNCR) (lb/hr)	Boiler Operating at 50% Reduced Nominal Load (Baghouse and Scrubber and SNCR Operational) (lb/hr)	Boiler Operating at 75% Reduced Nominal Load (Baghouse, Scrubber and SNCR Operational) (lb/hr)	Boiler Operating at 100% Nominal Load (Baghouse, Scrubber and SNCR Operational) (lb/hr)
Minor HAPs:				3.91E-01	7.18E-05	1.10E-01	1.84E-01	2.76E-01	3.68E-01
Acetophenone	3.20E-09	0	0%	1.60E-06	0	4.52E-07	7.54E-07	1.13E-06	1.51E-06
Benzoic acid (chloramben)	4.70E-08	0	0%	2.35E-05	0	6.64E-06	1.11E-05	1.66E-05	2.21E-05
bis(2-Ethylhexyl)phthalate (DEHP)	4.70E-08	0	0%	2.35E-05	0	6.64E-06	1.11E-05	1.66E-05	2.21E-05
Bromomethane (methl bromide)	1.50E-05	0	0%	7.50E-03	0	2.12E-03	3.53E-03	5.30E-03	7.07E-03
Carbon tetrachloride	4.50E-05	0	0%	2.25E-02	0	6.36E-03	1.06E-02	1.59E-02	2.12E-02
Chlorobenzene	3.30E-05	0	0%	1.65E-02	0	4.66E-03	7.77E-03	1.17E-02	1.55E-02
Chloroform	2.80E-05	0	0%	1.40E-02	0	3.96E-03	6.59E-03	9.89E-03	1.32E-02
Chloromethane (methyl chloride)	2.30E-05	0	0%	1.15E-02	0	3.25E-03	5.42E-03	8.12E-03	1.08E-02
Dichlorobenzene	0	1.18E-06	0%	0	7.18E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
1,2-Dichloroethane (ethylene dichloride)	2.90E-05	0	0%	1.45E-02	0	4.10E-03	6.83E-03	1.02E-02	1.37E-02
1,2-Dichloropropane (propylene dichloride)	3.30E-05	0	0%	1.65E-02	0	4.66E-03	7.77E-03	1.17E-02	1.55E-02
2,4-Dinitrophenol	1.80E-07	0	0%	9.00E-05	0	2.54E-05	4.24E-05	6.36E-05	8.48E-05
Dichloromethane (methylene chloride)	2.90E-04	0	0%	1.45E-01	0	4.10E-02	6.83E-02	1.02E-01	1.37E-01
Ethylbenzene	3.10E-05	0	0%	1.55E-02	0	4.38E-03	7.30E-03	1.10E-02	1.46E-02
Pentachlorophenol	5.10E-08	0	0%	2.55E-05	0	7.21E-06	1.20E-05	1.80E-05	2.40E-05
4-Nitrophenol	1.10E-07	0	0%	5.50E-05	0	1.55E-05	2.59E-05	3.89E-05	5.18E-05
Phenol	5.10E-05	0	0%	2.55E-02	0	7.21E-03	1.20E-02	1.80E-02	2.40E-02
Propionaldehyde	6.10E-05	0	0%	3.05E-02	0	8.62E-03	1.44E-02	2.15E-02	2.87E-02
Tetrachloroethene	3.80E-05	0	0%	1.90E-02	0	5.37E-03	8.95E-03	1.34E-02	1.79E-02
1,1,1-Trichloroethane (methyl chloroform)	3.10E-05	0	0%	1.55E-02	0	4.38E-03	7.30E-03	1.10E-02	1.46E-02
Trichloroethene	3.00E-05	0	0%	1.50E-02	0	4.24E-03	7.07E-03	1.06E-02	1.41E-02
2,4,6-Trichlorophenol	2.20E-08	0	0%	1.10E-05	0	3.11E-06	5.18E-06	7.77E-06	1.04E-05
Vinyl chloride	1.80E-05	0	0%	9.00E-03	0	2.54E-03	4.24E-03	6.36E-03	8.48E-03
o-Xylene	2.50E-05	0	0%	1.25E-02	0	3.53E-03	5.89E-03	8.83E-03	1.18E-02

EP-20001
Biomass-Fired FBC Boiler During Start-Up and at Reduced Loads

Pollutant	Biomass Emission Factor (lb/MMBtu)	Fully Operational Biomass-Fired Stoker Boiler Controlled (lb/hr)	Boiler During Initial Start-up Burning Natural Gas Only (lb/hr)	Boiler Operating at 30% Reduced Nominal Load (Baghouse and Scrubber Operational, no SNCR) (lb/hr)	Boiler Operating at 50% Reduced Nominal Load (Baghouse and Scrubber and SNCR Operational) (lb/hr)	Boiler Operating at 75% Reduced Nominal Load (Baghouse, Scrubber and SNCR Operational) (lb/hr)	Boiler Operating at 100% Nominal Load (Baghouse, Scrubber and SNCR Operational) (lb/hr)
Polychlorinated biphenyls:		3.96E-06	0	1.12E-06	1.87E-06	2.80E-06	3.73E-06
Decachlorobiphenyl	2.70E-10	1.35E-07	0	3.82E-08	6.36E-08	9.54E-08	1.27E-07
Dichlorobiphenyl	7.40E-10	3.70E-07	0	1.05E-07	1.74E-07	2.61E-07	3.49E-07
Heptachlorobiphenyl	6.60E-11	3.30E-08	0	9.33E-09	1.55E-08	2.33E-08	3.11E-08
Hexachlorobiphenyl	5.50E-10	2.75E-07	0	7.77E-08	1.30E-07	1.94E-07	2.59E-07
Pentachlorobiphenyl	1.20E-09	6.00E-07	0	1.70E-07	2.83E-07	4.24E-07	5.65E-07
Trichlorobiphenyl	2.60E-09	1.30E-06	0	3.67E-07	6.12E-07	9.18E-07	1.22E-06
Tetrachlorobiphenyl	2.50E-09	1.25E-06	0	3.53E-07	5.89E-07	8.83E-07	1.18E-06

Pollutant	Biomass Emission Factor (lb/MMBtu)	Natural Gas Emission Factor (lb/MMBtu)	Fully Operational Biomass-Fired Stoker Boiler Controlled (lb/hr)	Boiler During Initial Start-up Burning Natural Gas Only (lb/hr)	Boiler Operating at 30% Reduced Nominal Load (Baghouse and Scrubber Operational, no SNCR) (lb/hr)	Boiler Operating at 50% Reduced Nominal Load (Baghouse and Scrubber and SNCR Operational) (lb/hr)	Boiler Operating at 75% Reduced Nominal Load (Baghouse, Scrubber and SNCR Operational) (lb/hr)	Boiler Operating at 100% Nominal Load (Baghouse, Scrubber and SNCR Operational) (lb/hr)
Polycyclic Organic Matter:			1.40E-02	3.10E-06	3.95E-03	6.59E-03	9.88E-03	1.32E-02
Benzo(a)anthracene	6.50E-08	0	3.25E-05	0	9.18E-06	1.53E-05	2.30E-05	3.06E-05
Benzo(a)pyrene	2.60E-06	0	1.30E-03	0	3.67E-04	6.12E-04	9.18E-04	1.22E-03
Benzo(b)fluoranthene	1.00E-07	0	5.00E-05	0	1.41E-05	2.36E-05	3.53E-05	4.71E-05
Benzo(e)pyrene	2.60E-09	0	1.30E-06	0	3.67E-07	6.12E-07	9.18E-07	1.22E-06
Benzo(g,h,i)perylene	9.30E-08	0	4.65E-05	0	1.31E-05	2.19E-05	3.29E-05	4.38E-05
Benzo(j,k)fluoranthene	1.60E-07	0	8.00E-05	0	2.26E-05	3.77E-05	5.65E-05	7.54E-05
Benzo(k)fluoranthene	3.60E-08	0	1.80E-05	0	5.09E-06	8.48E-06	1.27E-05	1.70E-05
Chrysene	3.80E-08	0	1.90E-05	0	5.37E-06	8.95E-06	1.34E-05	1.79E-05
Dibenzo(a,h)anthracene	9.10E-09	0	4.55E-06	0	1.29E-06	2.14E-06	3.21E-06	4.29E-06
Indeno(1,2,3,c,d)pyrene	8.70E-08	0	4.35E-05	0	1.23E-05	2.05E-05	3.07E-05	4.10E-05
Acenaphthene	9.10E-07	0	4.55E-04	0	1.29E-04	2.14E-04	3.21E-04	4.29E-04
Fluorene	3.40E-06	2.75E-09	1.70E-03	1.67E-07	4.80E-04	8.01E-04	1.20E-03	1.60E-03
Anthracene	3.00E-06	0	1.50E-03	0	4.24E-04	7.07E-04	1.06E-03	1.41E-03
Phenanthrene	7.00E-06	1.67E-08	3.50E-03	1.02E-06	9.89E-04	1.65E-03	2.47E-03	3.30E-03
Fluoranthene	1.60E-06	2.94E-09	8.00E-04	1.79E-07	2.26E-04	3.77E-04	5.65E-04	7.54E-04
Pyrene	3.70E-06	4.90E-09	1.85E-03	2.99E-07	5.23E-04	8.71E-04	1.31E-03	1.74E-03
Perylene	5.20E-10	0	2.60E-07	0	7.35E-08	1.22E-07	1.84E-07	2.45E-07
Acenaphthylene	5.00E-06	0	2.50E-03	0	7.07E-04	1.18E-03	1.77E-03	2.36E-03
2-Methylnaphthalene	1.60E-07	2.35E-08	8.00E-05	1.44E-06	2.26E-05	3.77E-05	5.65E-05	7.54E-05
2-Chloronaphthalene	2.40E-09	0	1.20E-06	0	3.39E-07	5.65E-07	8.48E-07	1.13E-06

EP-20001
Biomass-Fired FBC Boiler During Start-Up and at Reduced Loads

Pollutant	Biomass Emission Factor (lb/MMBtu)	Toxic Equivalency Factor (TEF)	Fully Operational Biomass-Fired Stoker Boiler Controlled (lb/hr)	Boiler During Initial Start-up Burning Natural Gas Only (lb/hr)	Boiler Operating at 30% Reduced Nominal Load (Baghouse and Scrubber Operational, no SNCR) (lb/hr)	Boiler Operating at 50% Reduced Nominal Load (Baghouse and Scrubber and SNCR Operational) (lb/hr)	Boiler Operating at 75% Reduced Nominal Load (Baghouse, Scrubber and SNCR Operational) (lb/hr)	Boiler Operating at 100% Nominal Load (Baghouse, Scrubber and SNCR Operational) (lb/hr)
Dibenzo furans:			4.19E-08	0	1.18E-08	1.97E-08	2.96E-08	3.94E-08
Heptachlorodibenzo-p-furans	2.40E-10	0	0.00E+00	0	0	0	0	0
Hexachlorodibenzo-p-furans	2.80E-10	0	0.00E+00	0	0	0	0	0
Octachlorodibenzo-p-furans	8.80E-11	0.001	4.40E-11	0	1.24E-11	2.07E-11	3.11E-11	4.14E-11
Pentachlorodibenzo-p-furans	4.20E-10	0	0.00E+00	0	0	0	0	0
2,3,7,8-Tetrachlorodibenzo-p-furans	9.00E-11	0.1	4.50E-09	0	1.27E-09	2.12E-09	3.18E-09	4.24E-09
Tetrachlorodibenzo-p-furans	7.50E-10	0	0.00E+00	0	0	0	0	0
Dioxins:								
Heptachlorodibenzo-p-dioxins	2.00E-09	0	0.00E+00	0	0	0	0	0
Hexachlorodibenzo-p-dioxins	3.19E-11	0	0.00E+00	0	0	0	0	0
Octachlorodibenzo-p-dioxins	6.60E-08	0.001	3.30E-08	0	9.33E-09	1.55E-08	2.33E-08	3.11E-08
Pentachlorodibenzo-p-dioxins	1.50E-09	0	0.00E+00	0	0	0	0	0
2,3,7,8-Tetrachlorodibenzo-p-dioxins	8.60E-12	1.0	4.30E-09	0	1.22E-09	2.03E-09	3.04E-09	4.05E-09
Tetrachlorodibenzo-p-dioxins	4.70E-10	0	0.00E+00	0	0	0	0	0

EP-20010 through EP-20040
Generators

Basis: Cummins Power Generation generator sets with a rating of 1,750 kilowatts (kW) continuous power, 1,837 kW maximum power, Model C1750 N6C specification sheet dated April 2009.

AP-42 Section 3.2, Natural Gas-fired Reciprocating Engines, Final Section, August 2000. Table 3.2-2. Uncontrolled Emission Factors for 4-Stroke Lean Burn Engines (SCC 2-02-002-54).

New Source Performance Standard (NSPS) 40 CFR Part 60, Subpart JJJJ § 60.4230(a)(4)(i) is applicable to ABBK as the proposed generator engines are stationary spark ignition (SI) internal combustion engines (ICE) that have commenced construction after June 12, 2006.

California Climate Action Registry (CCAR) General Reporting Protocol, Version 3.1, January 2009.

Criteria:

Unit Size Rating (100% of Rated Load)	1,750 kWe	
	2,463 Hp-hr	
	6.27 MMBtu	Based on 1 Hp-hr = 2,544.43 Btu
Maintenance Checks and Readiness Testing	100 hr/yr	

Source Details:

ID	Emission Source	Stack Flow Rate (cfm)	Stack Diameter (in)	Release Height (ft)	Stack Area (ft^2)	Gas Velocity (ft/sec)	Gas Velocity (m/s)	Gas Exit Temperature (deg F)	Gas Exit Temperature (deg K)
EP-20010	Generator Set #1	13,292	12	60	0.79	282.07	85.97	921	767
EP-20020	Generator Set #2	13,292	12	60	0.79	282.07	85.97	921	767
EP-20030	Generator Set #3	13,292	12	60	0.79	282.07	85.97	921	767
EP-20040	Generator Set #4	13,292	12	60	0.79	282.07	85.97	921	767

Emission Factors:

Criteria Pollutants	EF	Unit	Notes
NO_x Uncontrolled	0.882	g/Hp-hr	Reported Cummins Power Generation Emission Rate, July 24, 2012; includes 5% tolerance for data.
SO_2	0.00068	g/Hp-hr	AP-42 Section 3.2, Table 3.2-2, converted to g/Hp-hr. Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content in natural gas of 2,000 gr/10^6 scf.
CO	2.88	g/Hp-hr	Reported Cummins Power Generation Emission Rate, July 24, 2012; includes 15% tolerance for data
VOC	0.14	g/Hp-hr	AP-42 Section 3.2, Table 3.2-2, converted to g/Hp-hr.
$PM/PM_{10}/PM_{2.5}$	0.012	g/Hp-hr	AP-42 Section 3.2, Table 3.2-2, converted to g/Hp-hr. Includes both filterable and condensable fractions.
GHG Pollutants			
CO_2	135.01	lb/MMscf	CCAR Table C.7 (53.06 kg CO_2/MMBtu, 100% Oxidization), converted to g/Hp-hr.
CH_4	0.0025	lb/MMscf	CCAR Table C.8 (0.001 kg CH_4/MMBtu), converted to g/Hp-hr.
N_2O	0.00025	lb/MMscf	CCAR Table C.8 (0.0001 kg N_2O/MMBtu), converted to g/Hp-hr.

Emissions:	EP-20010	EP-20020	EP-20030	EP-20040	**TOTAL**	
Criteria Pollutants	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	**(lb/hr)**	**(ton/yr)**
NO_x	4.79	4.79	4.79	4.79	**19.16**	**0.96**
SO_2	0.0037	0.0037	0.0037	0.0037	**0.015**	**0.0007**
CO	15.61	15.61	15.61	15.61	**62.44**	**3.12**
VOC	0.74	0.74	0.74	0.74	**2.96**	**0.15**
$PM/PM_{10}/PM_{2.5}$	0.063	0.063	0.063	0.063	**0.25**	**0.013**
GHG Pollutants						
CO_2	733.08	733.08	733.08	733.08	**2,932.30**	**146.62**
CH_4	0.014	0.014	0.014	0.014	**0.055**	**0.0028**
N_2O	0.0014	0.0014	0.0014	0.0014	**0.0055**	**0.00028**

EP-20010 through EP-20040
Generators

HAPs from Natural Gas Combustion

Basis: AP-42 Section 3.2, Natural Gas-fired Reciprocating Engines, Final Section, August 2000. Table 3.2-2. Uncontrolled Emission Factors for 4-Stroke Lean Burn Engines (SCC 2-02-002-54).

Only factors for pollutants noted as HAPs as defined by Section 112(b) of the Clean Air Act listed.
AP-42 factors marked as "less than" are omitted as emissions from such pollutants are negligible.

Emission Factors:

HAPs	(lb/MMBtu)	(g/Hp-hr)
1,3-Butadiene	2.67E-04	3.08E-04
2-Methylnaphthalene	3.32E-05	3.83E-05
2,2,4-Trimethylpentane	2.50E-04	2.89E-04
Acenaphthene	1.25E-06	1.44E-06
Acenaphthylene	5.53E-06	6.38E-06
Acetaldehyde	8.36E-03	9.65E-03
Acrolein	5.14E-03	5.93E-03
Benzene	4.40E-04	5.08E-04
Benzo(b)fluoranthene	1.66E-07	1.92E-07
Benzo(e)pyrene	4.15E-07	4.79E-07
Benzo(g,h,i)perylene	4.14E-07	4.78E-07
Biphenyl	2.12E-04	2.45E-04
Chrysene	6.93E-07	8.00E-07
Ethylbenzene	3.97E-05	4.58E-05
Fluoranthene	1.11E-06	1.28E-06
Fluorene	5.67E-06	6.54E-06
Formaldehyde	5.28E-02	6.09E-02
Methanol	2.50E-03	2.89E-03
Methylene Chloride	2.00E-05	2.31E-05
n-Hexane	1.11E-03	1.28E-03
Naphthalene	7.44E-05	8.59E-05
PAH	2.69E-05	3.10E-05
Phenanthrene	1.04E-05	1.20E-05
Phenol	2.40E-05	2.77E-05
Pyrene	1.36E-06	1.57E-06
Tetrachloroethane	2.48E-06	2.86E-06
Toluene	4.08E-04	4.71E-04
Vinyl Chloride	1.49E-05	1.72E-05
Xylene	1.84E-04	2.12E-04
TOTAL	**7.19E-02**	**8.30E-02**

EP-20010 through EP-20040 Generators						
Emissions:	EP-20010	EP-20020	EP-20030	EP-20040	**TOTAL**	
HAPs	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	**(lb/hr)**	**(ton/yr)**
1,3-Butadiene	1.67E-03	1.67E-03	1.67E-03	1.67E-03	**6.69E-03**	**3.35E-04**
2-Methylnaphthalene	2.08E-04	2.08E-04	2.08E-04	2.08E-04	**8.32E-04**	**4.16E-05**
2,2,4-Trimethylpentane	1.57E-03	1.57E-03	1.57E-03	1.57E-03	**6.27E-03**	**3.13E-04**
Acenaphthene	7.83E-06	7.83E-06	7.83E-06	7.83E-06	**3.13E-05**	**1.57E-06**
Acenaphthylene	3.47E-05	3.47E-05	3.47E-05	3.47E-05	**1.39E-04**	**6.93E-06**
Acetaldehyde	5.24E-02	5.24E-02	5.24E-02	5.24E-02	**2.10E-01**	**1.05E-02**
Acrolein	3.22E-02	3.22E-02	3.22E-02	3.22E-02	**1.29E-01**	**6.44E-03**
Benzene	2.76E-03	2.76E-03	2.76E-03	2.76E-03	**1.10E-02**	**5.51E-04**
Benzo(b)fluoranthene	1.04E-06	1.04E-06	1.04E-06	1.04E-06	**4.16E-06**	**2.08E-07**
Benzo(e)pyrene	2.60E-06	2.60E-06	2.60E-06	2.60E-06	**1.04E-05**	**5.20E-07**
Benzo(g,h,i)perylene	2.59E-06	2.59E-06	2.59E-06	2.59E-06	**1.04E-05**	**5.19E-07**
Biphenyl	1.33E-03	1.33E-03	1.33E-03	1.33E-03	**5.31E-03**	**2.66E-04**
Chrysene	4.34E-06	4.34E-06	4.34E-06	4.34E-06	**1.74E-05**	**8.69E-07**
Ethylbenzene	2.49E-04	2.49E-04	2.49E-04	2.49E-04	**9.95E-04**	**4.98E-05**
Fluoranthene	6.96E-06	6.96E-06	6.96E-06	6.96E-06	**2.78E-05**	**1.39E-06**
Fluorene	3.55E-05	3.55E-05	3.55E-05	3.55E-05	**1.42E-04**	**7.11E-06**
Formaldehyde	3.31E-01	3.31E-01	3.31E-01	3.31E-01	**1.32E+00**	**6.62E-02**
Methanol	1.57E-02	1.57E-02	1.57E-02	1.57E-02	**6.27E-02**	**3.13E-03**
Methylene Chloride	1.25E-04	1.25E-04	1.25E-04	1.25E-04	**5.01E-04**	**2.51E-05**
n-Hexane	6.96E-03	6.96E-03	6.96E-03	6.96E-03	**2.78E-02**	**1.39E-03**
Naphthalene	4.66E-04	4.66E-04	4.66E-04	4.66E-04	**1.87E-03**	**9.33E-05**
PAH	1.69E-04	1.69E-04	1.69E-04	1.69E-04	**6.74E-04**	**3.37E-05**
Phenanthrene	6.52E-05	6.52E-05	6.52E-05	6.52E-05	**2.61E-04**	**1.30E-05**
Phenol	1.50E-04	1.50E-04	1.50E-04	1.50E-04	**6.02E-04**	**3.01E-05**
Pyrene	8.52E-06	8.52E-06	8.52E-06	8.52E-06	**3.41E-05**	**1.70E-06**
Tetrachloroethane	1.55E-05	1.55E-05	1.55E-05	1.55E-05	**6.22E-05**	**3.11E-06**
Toluene	2.56E-03	2.56E-03	2.56E-03	2.56E-03	**1.02E-02**	**5.11E-04**
Vinyl Chloride	9.34E-05	9.34E-05	9.34E-05	9.34E-05	**3.74E-04**	**1.87E-05**
Xylene	1.15E-03	1.15E-03	1.15E-03	1.15E-03	**4.61E-03**	**2.31E-04**
TOTAL	**0.45**	**0.45**	**0.45**	**0.45**	**1.80**	**0.090**

APPENDIX D
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS CALCULATIONS

Abengoa Bioenergy Biomass of Kansas, LLC Biorefinery Facility Hugoton, Kansas	Rev. 0

BACT Analysis Support

SCR and Catalytic Oxidation for NG Generators (EP-20010 through EP-20040)

Basis: Cummins Power Generation generator sets with a rating of 1,750 kilowatts (kW) continuous power, 1,837 kW maximum power, Model C1750 N6C specification sheet dated April 2009.

Criteria:

NG Generator 100% Rated Shaft Power	2,463 BHP-hr	[1] Gross Engine Power Output
Emergency Operating Time	500 hr/yr	

NG Generator 100% rated NOx emission rate	0.88 g/BHP-hr	[1] NOx Emissions + 5%
NG Generator 100% rated NOx emissions	2,172.37 g/hr	Calc
	4.79 lb/hr NOX	Calc
	1.20 ton/yr NOx	Calc
NG Generator 100% rated NOx emission w/ SCR @ 95% C	0.04 g/BHP-hr	95% Capture Efficiency
Amount of NOx reduced by using SCR	2,063.75 g/hr	Calc
	4.55 lb/hr NOX	Calc
	1.14 ton/yr NOx	Calc

NG Generator 100% rated CO emission rate	2.88 g/BHP-hr	[1] CO Emissions + 15%
NG Generator 100% rated CO emissions	7,081.13 g/hr	Calc
	15.61 lb/hr CO	Calc
	3.90 ton/yr CO	Calc
NG Generator 100% rated CO emission w/ Catalytic Oxidati	2.00 g/BHP-hr	40 CFR Part 60, Subpart JJJJ - Non-Emergency Engine Limit
Amount of CO reduced by using Catalytic Oxidation	2,155.13 g/hr	Calc
Amount of CO reduced by using Catalytic Oxidation	4.75 lb/hr CO	Calc
	1.19 ton/yr CO	Calc

SCR Cost Per Unit	$410,770	AEPC Change order
Catalytic Oxidation Cost Per Unit	$363,220	AEPC Change order

BACT Options	Total Capital Cost	Life Expectancy
SCR	$ 410,770 /per unit	10 years
Catalytic Oxidation	$ 363,220 /per unit	10 years

Annual Operating Costs	Assumed Zero for Worst-Case Estimate	$ -
Overhead Costs	Assumed Zero for Worst-Case Estimate	$ -
Annual Indirect Costs	Assumed Zero for Worst-Case Estimate	$ -
Interest	EPA's ACA software	7%
Capital Recovery Factor (CRF)	Based on 10 Years	0.1424

	SCR for NOx Reduction			
	Potential Emissions	Emissions Reduction	Equipment Capital Cost	Cost Per Ton of Pollutant Removed
	NOx	NOx		$/Ton for NOx
Uncontrolled (Baseline)	1.20	–	--	--
SCR	0.06	(1.14)	$ 410,770	$ 51,500

	Catalytic Oxidation for CO Reduction			
	Potential Emissions	Emissions Reduction	Equipment Capital Cost	Cost Per Ton of Pollutant Removed
	CO	CO		$/Ton for CO Only
Uncontrolled (Baseline)	3.90	--	--	--
Catalytic Oxidation	2.71	(1.19)	$ 363,220	$ 43,600

Kansas Department of Health and Environment
Bureau of Air and Radiation
Phone (785) 296-1570 Fax (785) 291-3953

Notification of Construction or Modification

(K.A.R. 28-19-300 Construction permits and approvals; applicability)

Check one: ☐Applying for a Permit under K.A.R. 28-19-300(a) ☐Applying for an Approval under K.A.R. 28-19-300(b)*

1) Source ID Number: ~~189031~~ 0231 C-10550

COPY

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2) Mailing Information:
   Company Name: Abengoa Bioenergy Biomass of Kansas
   Address: 16150 Main Circle Drive, Suite 300
   City, State, Zip: Chesterfield, Missouri, 63017

3) Source Location:
   Street Address: 1043 Road P
   City, County, State, Zip: Higoton, KS 67951
   Section, Township, Range: T33S, R37W, Sec 18
   Latitude & Longitude Coordinates:

4) NAICSC/SIC Code (Primary): 325193 for EH 221117 for Cogen

5) Primary Product Produced at the Source: Ethanol

6) Would this modification require a change in the current operating permit for your facility? • Yes • No

   If no, please explain:

7) Is a permit fee being submitted? • Yes • No

   If yes, please include the facility's federal employee identification number (FEIN #) 20-5181119

8) Person to Contact at the Site: Roger Hoffman Phone: (636)-346-6810
   Title: project Engineer

9) Person to Contact Concerning Permit: Bob Wildgen Phone: (636)-368-1670
   Title: Business Development Manager
   Email: robert.wildgen@bioenergy.abengoa.com Fax: (636)-536-6175

Please read before signing:

Reporting forms provided may not adequately describe some processes. Modify the forms if necessary. Include a written description of the activity being proposed, a description of where the air emissions are generated and exhausted and how they are controlled. A simple diagram showing the proposed activity addressed in this notification which produces air pollutants at the facility (process flow diagrams, plot plan, etc.) with emission points labeled must be submitted with reporting forms. Information that, if made public, would divulge methods or processes entitled to protection as trade secrets may be held confidential. See the reverse side of this page for the procedure to request information be held confidential. A copy of the Kansas Air Quality Statutes and Regulations will be provided upon request.

Name and Title: Gerson Santos-Leon / Executive Vice President
Address:
Signature: _____ Date: 12/12/12 Phone: (636) 579-0205

* If you do not know whether to apply for a permit or an approval, follow approval application procedures.

Procedures For Requesting Information To Be Held Confidential

March 15, 2006
Revision 6

An applicant may request that information submitted to the Department, other than emission data or information in any air quality permit or approval, be treated as confidential if the information would divulge methods or processes entitled to protection as trade secrets.

A request to designate information within the Department's air quality files as confidential must include:

(1) An uncensored copy of the document clearly marked as confidential;

(2) A copy of the document, or copies if more than one is required to be filed with the Department, with the confidential information masked;

(3) Specification of the type of information to be held as confidential (i.e., product formulations, process rates);

(4) Specification and justification of the reason the information is qualified by statute to be treated as confidential (competitive advantage, company developed secret formulation, trade secret); and

(5) A reference at each place in the document or documents where information is masked referring to the specification of the type of information masked and the specification and justification the information is qualified by statute to be treated as confidential.

ONLY THE CONFIDENTIAL INFORMATION ON ANY DOCUMENT MAY BE MASKED. ALL INFORMATION ON ANY DOCUMENT WHICH IS NOT CONFIDENTIAL MUST REMAIN LEGIBLE.

The information will be treated as confidential until the secretary has acted upon the request and the owner or operator has had the opportunity to exhaust any available remedies if the secretary determines the information is not confidential.

Complete this and all reporting forms and submit to:

Kansas Department of Health and Environment
Bureau of Air and Radiation
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366
(785) 296-1570

Sources located in Wyandotte County should obtain forms from, and submit forms to:

Unified Government of Wyandotte County
Department of Air Quality
619 Ann Avenue
Kansas City, KS 66101
(913) 573-6700

CALCULATING THE CONSTRUCTION PERMIT APPLICATION FEE

[These requirements are found at K.A.R. 28-19-304(b).]

Calculate the construction permit application fee as follows:

Estimated capital cost of the proposed activity for which the application is made, including the total cost of equipment and services to be capitalized.	**Line 1** $ 4,000,000	
Multiply by .05% (.0005)	x .0005	
Total	**Line 2** $ 2,000	
If Line 2 is less than $100, enter $100 on Line 3. If Line 2 is greater than $4,000, enter $4,000 on Line 3.		
Otherwise, copy Line 2 to Line 3.		
Construction permit application fee.	**Line 3** $ 2,000	Minimum fee is $100

Certifier of Capital Cost

Robert Wildgen
(Print)

(Signature)

12/12/12
Date

K.A.R. 28-19-350 is a complex regulation pertaining to prevention of significant deterioration (PSD). An additional fee of $1,500 will be required if a PSD review is necessary. If you believe the proposed activity in this Notification of Construction or Modification will be subject to the requirements of K.A.R. 28-19-350, contact the Department for further evaluation.

For purposes of construction permit or approval applications, the following are not considered modifications:

1. Routine maintenance or parts replacement.
2. An increase or decrease in operating hours or production rates if:
   a. production rate increases do not exceed the originally approved design capacity of the stationary source or emissions unit; and
   b. the increased potential-to-emit resulting from the change in operating hours or production rates do not exceed any emission or operating limitations imposed as a permit condition.

ABENGOA BIOENERGY BIOMASS OF KANSAS, LLC

100630

COPY

Date	Invoice No	Comment	Amount	Net Amount
12/12/2012	KDHE CONST PERMI	KDHE - Modified Construction P	5,500.00 USD	5,500.00 USD

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Check: 100630 12/13/2012 Kansas Dept of Health & Environ., CheckTotal: *********5,500.00* USD

THIS DOCUMENT HAS A COLORED SECURITY BACKGROUND. DO NOT CASH IF THE WORD "VOID" IS VISIBLE. THIS PAPER HAS AN ARTIFICIAL WATERMARK ON REVERSE SIDE AND IS ALTERATION PROTECTED.

ABENGOA BIOENERGY BIOMASS OF KANSAS, LLC
(636) 728-0508
16150 MAIN CIRCLE DRIVE, SUITE 200
CHESTERFIELD, MO 63017

DEUTSCHE BANK TRUST COMPANY AMERICAS
1-103/210

100630

FIVE THOUSAND FIVE HUNDRED AND ZERO CENTS

DATE	AMOUNT
12/13/2012	*********5,500.00*

VOID IF NOT CASHED IN 90 DAYS

PAY TO THE ORDER OF:

Kansas Dept of Health & Environ.,
1000 SW Jackson Street, Suite 310
Topeka, KS 66612-1366