2011 Updated Facility Design Ambient Air Quality Impact Assessment Supplement for Prevention of Significant Deterioration Air Quality Construction Permit Application Source ID No. 1890231

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Prepared For

Abengoa Bioenergy Biomass of Kansas, LLC
Hugoton, Kansas

WLA Project No. 165-009

August 2011

Revision No. 0

WLA
Consulting, Inc.
Engineers & Scientists
WaterLandAir

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Abengoa Bioenergy Biomass of Kansas, LLC
16150 Main Circle Drive, Suite 300
Chesterfield, MO 63017

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Prepared by:

Stephanie E. Salter, P.E.

WLA
Consulting, Inc.
Engineers & Scientists
1640 "L" Street, Suite D
Lincoln, Nebraska 68508
402.475.8588
402.477.1956 (fax)

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Section 1.0
Introduction and Purpose

1.1 Current Proposed Project

Abengoa Bioenergy Biomass of Kansas, LLC (ABBK) intends to build and operate a biomass-to-ethanol and biomass-to-energy production facility. The proposed facility will employ two different biomass processes to produce fuel ethanol, lignin-rich stillage and stillage syrup, soil amendment ash, and power. These two processes include the following:

- Biomass-to-Ethanol: Enzymatic Hydrolysis Ethanol Production Process (EH Plant), 30 Million Gallon Per Year Anhydrous Ethanol Capacity; and
- Biomass-to-Power: Cogeneration Process (CoGen Plant), 22 Megawatt Capacity.

1.2 Purpose of AQIA Supplement

An Air Quality Impact Assessment (AQIA) Supplement for the proposed facility was performed to support the approval of the Prevention of Significant Deterioration, Air Quality Construction Permit Application for the 2011 Updated Facility Design, in accordance with K.A.R. 28-19-350. The purpose of the AQIA Supplement is to address concerns regarding the modeling completed to demonstrate that the proposed facility will not cause or contribute to ambient air concentrations in excess of the applicable 1-hour NO_2 NAAQS.

1.3 AQIA and PSD Additional Impacts Analyses Procedure and Results

This report relies on the technical procedures discussed in the June 2011 AQIA and PSD additional impacts analyses report and the July 31, 2011 Ambient Air Dispersion Modeling Protocol Memorandum submitted to the Kansas Department of Health and Environment (KDHE) including KDHE's comments. This report presents the results of the 1-hour NO_2 NAAQS analysis and is intended to be a supplement to the PSD air quality construction application.

Section 2.0
Modeling Parameters and Procedures Clarification

2.1 Boiler Emissions and Stack Parameters

The biomass-fired boiler's NOx emissions will be controlled by a Selective Catalytic Reduction (SCR). The SCR will be guaranteed by the vendor to achieve a0.30 lb/MMBtu NOx emission rate. The revised boiler's potential to emit calculations are presented in Appendix A along with the revised controlled facility-wide PTE summary.

Other pollutant emissions have not changed with the addition of the SCR. The stack parameters (height, diameter, exit velocity and temperature) also have not changed.

2.2 Source Groupings

As indicated by EPA in a July 29, 2011 email, AERMOD cannot correctly calculate impacts using the PVMRM or OLM options when a single source is included in a model run multiple times. The previous 1-hour NO_2 NAAQS analysis submitted in June 2011 had included all boiler loads in a single model run. Per EPA, each boiler load must be run in a separate model run. Therefore, for this 1-hour NO_2 NAAQS analysis, each boiler load has been modeled separately. The boiler loads modeled are as follows:

- Normal operations were assumed to include the boiler operating at 353 MMBtu/hr to the maximum 500 MMBtu/hr heat input rating. There were three scenarios evaluated for the normal operations:
  - 353 MMBtu/hr (or 75% load);
  - 471 MMBtu/hr (or 100% load); and
  - 500 MMBtu/hr (or 120% load).
- Start-up and shutdown operations were assumed to include the boiler operating below 353 MMBtu/hr. There were two scenarios evaluated for the start-up and shutdown operations:
  - 141 MMBtu/hr (or 30% load); and
  - 236 MMBtu/hr (or 50%load).

2.3 Facility Center

The facility's approximate center UTM coordinates used in the June 2011 AQIA and PSD additional impacts analyses report was as follows: Easting: 2883551, Northing: 4117494.

2.4 1-Hour NO_2 Receptor Grids

An initial fenceline along the facility boundary was established with 50 meter spacing. The additional SIL receptors used for the 1-hour NO_2 SIL analysis included a multi-tiered grid as shown in Table 3-2.

Table 2–1
Receptor Spacing for Significant Impact Modeling

Receptor Grid Type	Distance from Facility Boundary	Receptor Spacing
Extra Fine	Fenceline to 1,000+ m	50 m
Fine	1,000 m to 2,000 m	100 m
Medium	2,000m to 5,000 m	250 m
Coarse	5,000 m to 10,000 m	500 m
Extra Coarse	10,000 m to 50,000 m	1,000 m

Because AERMOD is intended for estimating impacts from short-range transport (distances less than 50 km from the source), the receptor grid did not extend beyond 50 km.

As previously approved by KDHE and EPA, the receptors in the 1-hour NO_2 NAAQS cumulative impact analysis was limited to only those receptors that had significant impacts based on the SIL analysis.

2.5 Significant Impact Analysis for 1-Hour NO_2 NAAQS

The significance level for the 1-hour NO_2 averaging period is based on the EPA memorandum, *General Guidelines for Implementing the 1-Hour NO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-Hour NO_2 Significant Impact Level*, published June 28, 2010. This EPA memo established the significance level for the 1-hour NO_2 averaging period at 0.004 ppm (7.53 $\mu g/m^3$), to be compared to the highest of the 5 year averages of the maximum modeled concentrations predicted each year at each receptor.

2.6 Cumulative Impact Analysis for 1-Hour NO_2 NAAQS Compliance

The cumulative impact analysis included the facility impacts plus nearby NAAQS sources in the vicinity of the proposed facility. Background ambient concentrations were added to the model-predicted concentrations from the proposed facility for comparison to the NAAQS.

2.7 Conversion of Concentration

The conversion of the significance level concentration in parts per million by volume (ppmv) to micrograms per cubic meter ($\mu g/m^3$) for NO_2, for comparison to the NAAQS will be performed using the following equation:

$$C_{\mu g/m^3} = C_{ppm} / 0.02445 \times MW$$

where:

C = Concentration of the contaminant, in ppm or $\mu g/m^3$

MW = Molecular weight of NO_2 = 46.01 grams/mole (g/mol)

0.02445 = Constant representing the volume, in liters, of one mole of a gas at standard temperature (25°C) and pressure (1 atmosphere).

2.8 Nearby Source Information

As directed by KDHE, the nearby source inventory data was revised to include only those sources within 20 km of the proposed facility. The nearby source inventory used for this 1-hour NO_2 NAAQS analysis is included in Appendix B. From the original KDHE nearby source inventory, the distance from the proposed facility to the following sources: WTG Hugoton, LP (Facility IDs. 0550009 and 0550024) and Tyson Fresh Meats, Inc. (Facility ID. 0550043), was corrected. In the original KDHE nearby source inventory, the facility center coordinate was as follows: Easting: 326390, Northing: 4200234. With the corrected facility center coordinate, these three sources were calculated to be greater than 20 km from the facility.

Section 3.0
Preliminary Modeling Analysis

3.1 Preliminary Modeling Analysis (aka Significant Impact Analysis) Results

Table 3–1
Predicted Facility Impacts Compared to Significance Levels and Pre-application Monitoring Thresholds

Pollutant	Avg. Period	Maximum Predicted Facility Impacts (μg/m³)	SIL (μg/m³)	Exceeds SIL (Yes/No)	Pre-application Monitoring Threshold Concentration (μg/m³)	Exceeds Monitoring Threshold (Yes/No)
NO_2	1-Hour	20.49	7.53 Note 1	**Yes**	N/A	N/A

Note 1: Recommended SILs per EPA memoranda.

Figures 3-1 through 3-5 depict the isopleths where the respective 1-hour NO_2 SIL is exceeded for each pollutant and averaging period evaluated in the refined modeling analysis.

Figure 3–1
NO_2 PVMRM 1-Hour SIL Isopleth (EPA Interim SIL = 7.53 μg/m³; Source: AB500)

Plot Based on 100th Percentile (1st High 20.13 μg/m³)

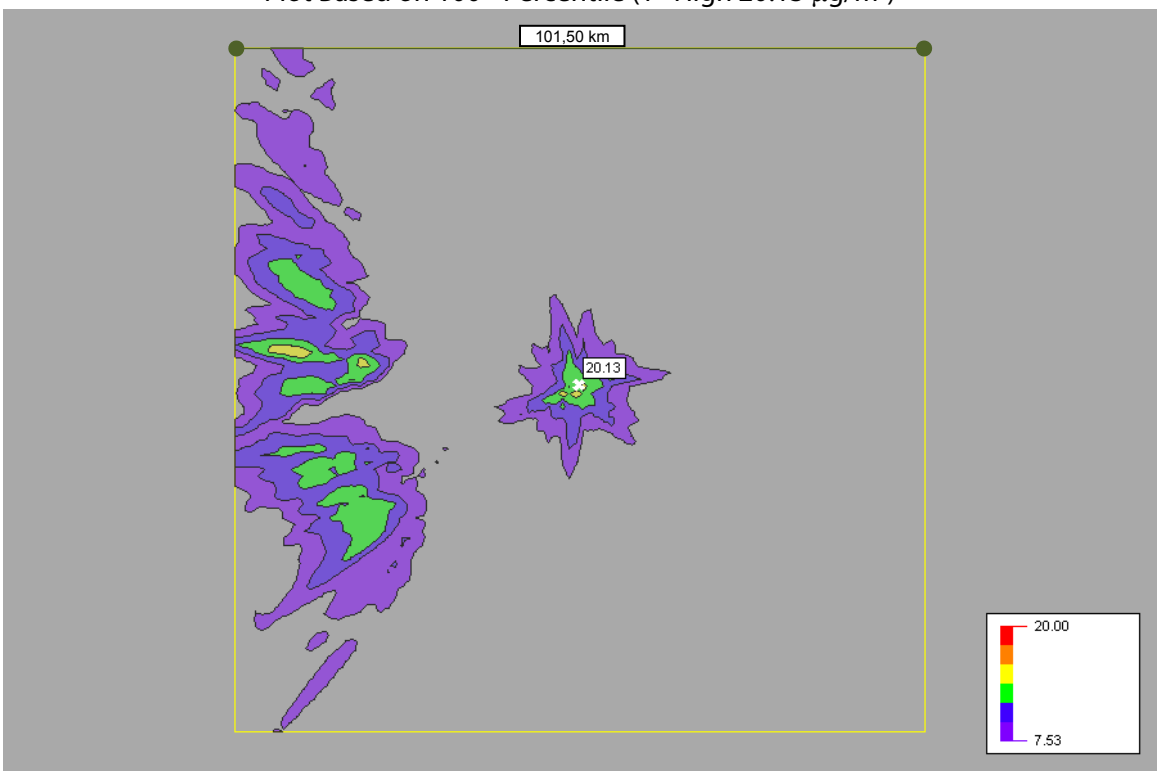


Figure 3–2
NO_2 PVMRM 1-Hour SIL Isopleth (EPA Interim SIL = 7.53 μg/m³; Source: AB471)

Plot Based on 100th Percentile (1st High 20.49 μg/m³)

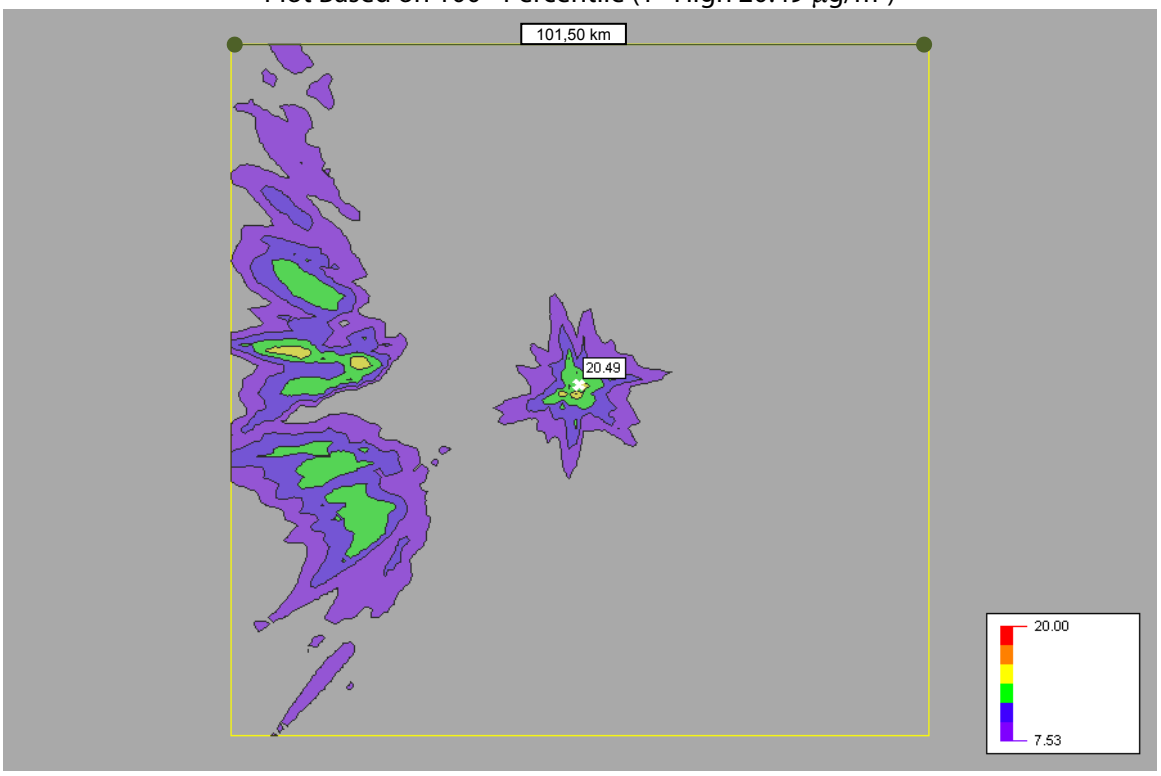


Figure 3–3
NO_2 PVMRM 1-Hour SIL Isopleth (EPA Interim SIL = 7.53 μg/m³; Source: AB353)

Plot Based on 100th Percentile (1st High 18.86 μg/m³)

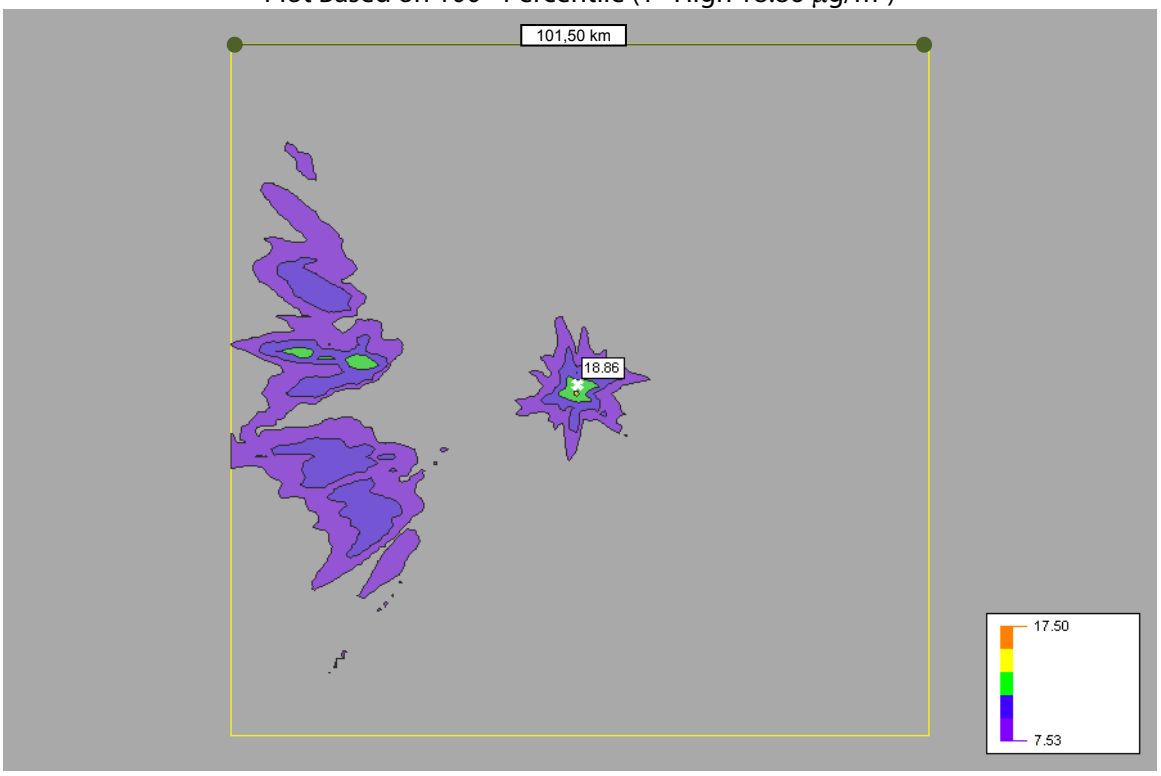


Figure 3–4
NO_2 PVMRM 1-Hour SIL Isopleth (EPA Interim SIL = 7.53 μg/m³; Source: AB236)

Plot Based on 100th Percentile (1st High 17.40 μg/m³)

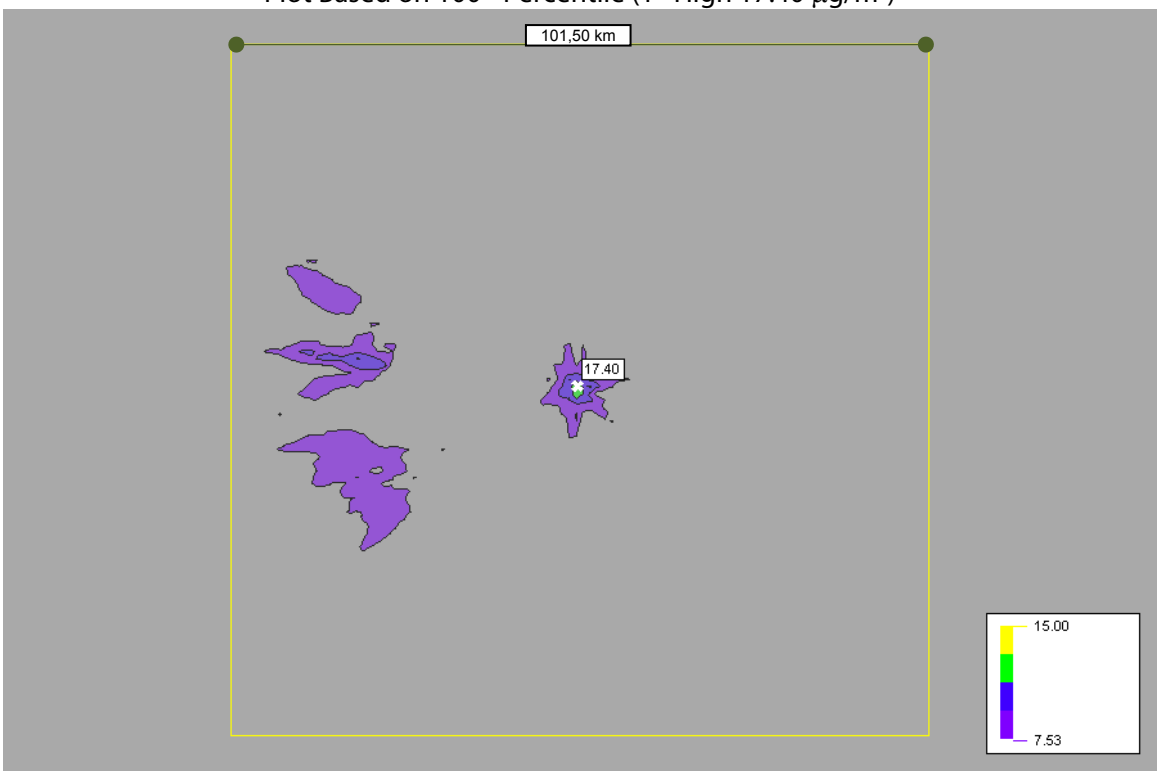
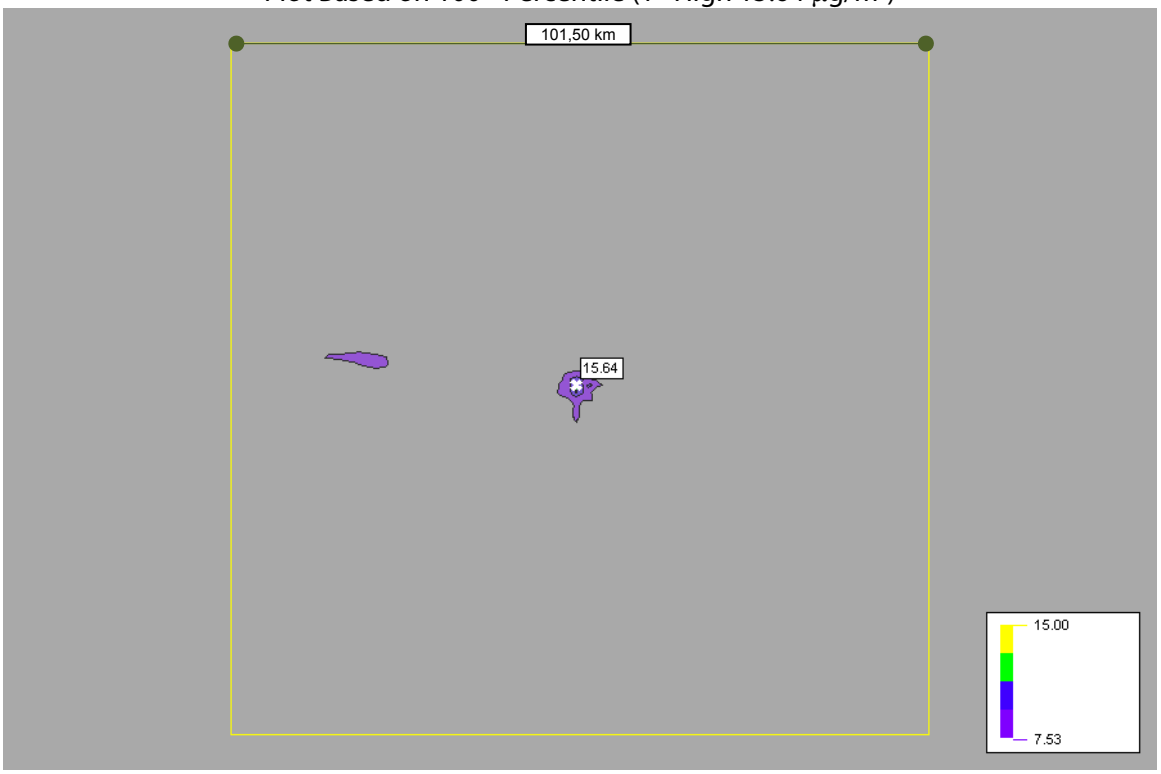


Figure 3–5
NO_2 PVMRM 1-Hour SIL Isopleth (EPA Interim SIL = 7.53 μg/m³; Source: AB141)

Plot Based on 100th Percentile (1st High 15.64 μg/m³)



3.2 Refined Modeling Analysis for NAAQS and PSD Increment Compliance

The second component of the AQIA consisted of a refined modeling analysis to demonstrate that the proposed facility will not cause or contribute to any violations of the 1-hour NO_2 NAAQS. The refined modeling analysis, including all appropriate regional emission sources (other nearby facilities) out to 20 kilometers per recommendations made by KDHE.

The refined modeling analysis takes into account the combined impacts of emissions from the proposed facility, contributions from nearby major and minor sources and background concentrations due to distant major and minor sources and natural sources.

The modeling results for the NO_2 NAAQS analysis indicate that the maximum predicted NO_2 concentrations for the 1-hour period will not exceed the NAAQS when the emission rates associated with the implementation of an SCR for control of NOx from the biomass-fired boiler (BL-20001), and the model parameters and modeling methodology presented in the June 2011 AQIA and PSD additional impacts analyses report are used.

The predicted cumulative 1-hour NO_2 impacts are based on the 5-year average of the 98th percentile of 1-hour average concentrations at each receptor for comparison to the NAAQS, in accordance with the EPA memo, *General Guidelines for Implementing the 1-Hour NO_2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, Including an Interim 1-Hour NO_2 Significant Impact Level,* dated June 28, 2010. Impacts were obtained by using the non-regulatory NO_2 – Plume Volume Molar Ratio Method (PVMRM) option. An NO_2 contribution analysis was performed to demonstrate that the facility's contributions were below the SIL when a NAAQS exceedance was indicated at a given receptor using MAXDCONT output file option in AERMOD.

Results of the 1-hour NO_2 NAAQS analysis are summarized in Table 3-2. The 1-hour averaging period background concentration used for comparison to the NAAQS was 49 `$\mu g/m^3$.

Table 3–2
Predicted Cumulative 1-Hour NO_2 Concentration for NAAQS Evaluation

NO2 1-HOUR		Predicted H8H ALL Impacts (Plus Background)	ABBK Contribution	UTM Easting	UTM Northing
AERMOD 11103	Operating Scenarios			(m)	(m)
NAQ500 Includes Nearby Sources	Boiler at 500 MMBtu/hr Flare Operational No Firewater Pump	643.41588 (692.41588)	0.00008	293557.00	4125082.00
NAQ471 Includes Nearby Sources	Boiler at 471 MMBtu/hr Flare Operational No Firewater Pump	643.41588 (692.41588)	0.00008	293557.00	4125082.00
NAQ353 Includes Nearby Sources	Boiler at 353 MMBtu/hr Flare Operational No Firewater Pump	627.81448 (676.81448)	0.00009	293057.00	4112082.00
NAQ236 Includes Nearby Sources	Boiler at 236 MMBtu/hr Flare Operational No Firewater Pump	570.46361 (619.46361)	0.00005	288807.00	4122582.00
NAQ141 Includes Nearby Sources	Boiler at 141 MMBtu/hr Flare Operational No Firewater Pump	500.28631 (549.28631)	0.00006	285957.00	4117782.00

The 1-hour NO_2 H1H predicted impact for the worst-case scenario is 643.41588 $\mu g/m^3$. The predicted impact plus background is 692.41588 $\mu g/m^3$.

The MAXDCONT output option was used to determine the contribution from the proposed facility when a NAAQS exceedance occurred. Tables 3-3 through 3-5 summarize the results of the contribution analysis where a SIL exceedance was identified concurrent with a NAAQS exceedance based on a maximum concentration of 139.7 $\mu g/m_3$ (188.7 $\mu g/m^3$ minus background). There was no SIL exceedance identified concurrent with a NAAQS exceedance past the H3H for the 500 MMBtu/hr, 471 MMBtu/hr and 353 MMBtu/hr boiler load scenarios. There were no SIL exceedances identified concurrent with a NAAQS exceedance for the 236 MMBtu/hr and 141 MMBtu/hr boiler load scenarios. The contribution analysis reviewed all ranks until there was no longer an exceedance of the NAAQS (high 148TH high rank) based on a maximum concentration of 139.7 $\mu g/m_3$ (188.7 $\mu g/m^3$ minus background).

Table 3–3
1-Hour NO_2 NAAQS Contribution Analysis Summary for NAQ500 Scenario

UTM Easting (m)	UTM Northing (m)	Rank	Contribution AB500 (μg/m³)	Contribution NAQ500 (μg/m³)	Contribution Nearby (μg/m³)
255557	4125082	1ST	7.67973	178.5631	170.8833
252557	4126082	1ST	8.50229	175.3755	166.8732
258557	4124082	1ST	7.67207	175.3427	167.6706
254557	4125082	1ST	7.59006	174.6559	167.0659
255557	4125082	3RD	8.96754	143.4753	134.5077

Table 3–4
1-Hour NO_2 NAAQS Contribution Analysis Summary for NAQ471 Scenario

UTM Easting (m)	UTM Northing (m)	Rank	Contribution AB471 (μg/m³)	Contribution NAQ471 (μg/m³)	Contribution Nearby (μg/m³)
260557	4124082	1ST	7.69418	244.9195	237.2253
255557	4125082	1ST	7.97417	178.8575	170.8833
258557	4124082	1ST	8.10537	175.9799	167.8745
252557	4126082	1ST	8.72086	175.5941	166.8732
254557	4125082	1ST	7.92959	174.9954	167.0659
255557	4125082	3RD	9.11603	143.6238	134.5077

Table 3–5
1-Hour NO_2 NAAQS Contribution Analysis Summary for NAQ353 Scenario

UTM Easting (m)	UTM Northing (m)	Rank	Contribution AB353 (μg/m³)	Contribution NAQ353 (μg/m³)	Contribution Nearby (μg/m³)
255557	4125082	3RD	7.55973	142.0675	134.5077

3.3 AQIA Summary

This AQIA demonstrates that the proposed facility will not cause or significantly contribute to a violation of the 1-hour NO_2 NAAQS. All AERMOD input/output files, support files and readme file are included in Appendix C.

Appendix A

Revised Biomass-Fired Boiler's Potential to Emit Calculations

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

Rev. 5.1

Operations Data

Plant Capacity:	Denatured Ethanol:	31.58 MMgpy	**Biomass:**	589,475 ton/yr
	Anhydrous Ethanol:	30 MMgpy		

Operations:	365 day/yr
	8760 hr/yr

CONTROLLED Potential to Emit Summary (TPY)

Emission Point No.	Emission Unit(s)	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	CO	VOC	Single HAP	Total HAPs	Direct $CO_2 + CO_2e$
HAUL ROADS											
EP-01000FUG	Paved Plant Roads	7.51	1.50	0.37	--	--	--	--	--	--	--
EP-01050FUG	Biomass Laydown Roads	2.87	0.73	0.07	--	--	--	--	--	--	--
ENZYMATIC HYDROLYSIS PLANT											
EP-11120	Floor Sweep System DC	1.17	1.17	0.20	--	--	--	--	--	--	--
EP-11110	Bale Grinder DC	21.61	21.61	3.67	--	--	--	--	--	--	--
EP-11170	Classifier Cyclone # 1 DC	3.24	3.24	0.55	--	--	--	--	--	--	--
EP-11270	Classifier Cyclone # 2 DC	3.24	3.24	0.55	--	--	--	--	--	--	--
EP-11711	Boiler Feed System DC	3.24	3.24	0.55	--	--	--	--	--	--	--
EP-11110FUG	Crop Receiving, Grinding and Conveying	0.16	0.07	0.01	--	--	--	--	--	--	--
EP-18185	EH Fermentation CO2 Scrubber	0.44	0.44	0.44	0.29	--	--	11.87	1.47	1.68	88,356.94
EP-19001FUG	Lignin-Rich Stillage Storage	--	--	--	--	--	--	1.29	0.03	0.06	--

CONTROLLED Potential to Emit Summary (TPY)

Emission Point No.	Emission Unit(s)	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	CO	VOC	Single HAP	Total HAPs	Direct $CO_2 + CO_2e$
ETHANOL STORAGE AND PIPING											
EP-02000	Fugitive Leaks	--	--	--	--	--	--	1.69	0.00	0.00	0.01
T-02107	EH Product Shift Tank #1	--	--	--	--	--	--	0.15	0.00	0.00	--
T-02108	EH Product Shift Tank #2	--	--	--	--	--	--	0.15	0.00	0.00	--
T-02102	EH Ethanol Product Storage Tank #1	--	--	--	--	--	--	0.22	0.00	0.00	--
T-02112	EH Ethanol Product Storage Tank #2	--	--	--	--	--	--	0.22	0.00	0.00	--
T-02105	EH Denaturant Storage Tank	--	--	--	--	--	--	1.27	0.01	0.01	--
EP-02100	Vapor Recovery System	--	--	--	--	--	--	Emitted Through Flare, EP-09001			--
EP-02100FUG	Loading Losses	--	--	--	--	--	--	0.75	0.01	0.01	--
UTILITIES											
EP-02710	Bulk Fly Ash Load-Out Silo	4.22	4.22	2.11	--	--	--	--	--	--	--
EP-02711	Bulk Fly Ash Load-Out Silo Spout	4.22	4.22	2.11	--	--	--	--	--	--	--
EP-04001	Cooling Water Tower	0.74	0.52	0.31	--	--	--	--	--	--	--
EP-20001	Biomass-Fired Stoker Boiler #1	69.07	65.66	61.68	661.17	464.96	481.99	11.17	5.69	18.40	481,650
EP-20514	Boiler Bottoms Ash Handling DC #1	4.22	4.22	2.11	--	--	--	--	--	--	--
EP-20510	Boiler Fly Ash Handling DC #1	2.11	2.11	1.05	--	--	--	--	--	--	--
EP-20520	Boiler Fly Ash Handling DC #2	2.11	2.11	1.05	--	--	--	--	--	--	--
EP-20512	Lime Handling DC #1	0.30	0.30	0.15	--	--	--	--	--	--	--
EP-09001	Flare	0.003	0.003	0.003	6.92	18.43	37.47	0.27	0.00	0.00	20,166
EP-06001 (EMG)	Firewater Pump Engine	0.004	0.004	0.004	0.13	0.05	0.03	0.00	0.00	0.00	119
EP-08000	High Voltage Circuit Breakers Fugitive Leaks	--	--	--	--	--	--	--	--	--	4.9
Total Plantwide		**130.5**	**118.6**	**77.0**	**668.5**	**483.4**	**519.5**	**29.1**	**5.7**	**20.2**	**590,297**

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:

		Stack Flow 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

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

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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

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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

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

Emission Factors: Nominal TYPICAL Fuel Blend		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	--		3,568.67	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	--		3,186.32	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	--		2,740.23	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	216.04	Boiler fuel criteria engineering calculations - 100% conversion fuel carbon to CO_2.
CH_4		--		33.23	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		

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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		57%	325.79	1,426.95	140.09	613.59	0.30	As guaranteed by vendor with SCR.
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%	3,568.67	15,630.79	7.14	31.26	0.015	
PM_{10}	Filterable	99.8%	3,186.32	13,956.06	6.37	27.91	0.014	
$PM_{2.5}$	Filterable	99.8%	2,740.23	12,002.21	5.48	24.00	0.012	
PM	Condensible	0%	8.01	35.07	8.01	35.07	0.017	
PM_{10}	Condensible	0%	8.01	35.07	8.01	35.07	0.017	
$PM_{2.5}$	Condensible	0%	8.01	35.07	8.01	35.07	0.017	
Lead		0%	0.02	0.10	0.02	0.10	--	
NH_3		0%	--	--	6.40	28.03	--	
GHG Pollutants								
CO_2		0%	101,756	445,691	101,756	445,691	--	
CH_4		0%	33.23	145.56	33.23	145.56	--	
N_2O		0%	4.36	19.11	4.36	19.11	--	

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Biomass-Fired Stoker Boiler

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

Emission Factors: Maximum WORST CASE Fuel Blend		Combined Fuels	Process Vents	Total		
Criteria Pollutants		(lb/dry ton)	(lb/hr)	(lb/hr)	(lb/MMBtu)	Notes:
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	--		3,634.40	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	--		3,245.00	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	--		2,790.70	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	215.58	Boiler fuel criteria engineering calculations - 100% conversion fuel carbon to CO_2.
CH_4		--		35.28	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		

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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		60%	377.38	1,652.92	150.95	661.17	0.30	As guaranteed by vendor with SCR.
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%	3,634.40	15,918.67	7.27	31.84	0.015	
PM_{10}	Filterable	99.8%	3,245.00	14,213.10	6.49	28.43	0.013	
$PM_{2.5}$	Filterable	99.8%	2,790.70	12,223.27	5.58	24.45	0.011	
PM	Condensible	0%	8.50	37.23	8.50	37.23	0.017	
PM_{10}	Condensible	0%	8.50	37.23	8.50	37.23	0.017	
$PM_{2.5}$	Condensible	0%	8.50	37.23	8.50	37.23	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%	35.28	154.53	35.28	154.53	--	
N_2O		0%	4.63	20.28	4.63	20.28	--	

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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	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		

EP-20001 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		60%	190.10	832.63	76.04	333.05	0.216
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	24.92	--
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	--

Abengoa Bioenergy Biomass of Kansas, LLC **Rev. 5.1**
Biorefinery Facility
Hugoton, Kansas

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 ^{o}C (approximately 4 hours). The spray dry absorber (SDA) scrubber is started when the appropriate operating temperature is achieved. No fuels other than natural gas will be combusted until the SDA scrubber and SCR are operational. The SCR 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, SDA Scrubber and SCR Operational).
50% of Nominal Heat Input When Fully Operational	236	MMBtu/hr	Approximately 50% Load of Nominal Design (Baghouse, SDA Scrubber and SCR Operational).
75% of Nominal Heat Input When Fully Operational	353	MMBtu/hr	Approximately 75% Load of Nominal Design (Baghouse, SDA Scrubber and SCR 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

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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	--		3,634.40	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	--		3,245.00	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	--		2,790.70	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	215.58	Boiler fuel criteria engineering calculations - 100% conversion fuel carbon to CO_2.	
CH_4		--		35.28	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).	

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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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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**	**Boiler Operating at 30% Reduced Nominal Load**	**Boiler Operating at 50% Reduced Nominal Load**	**Boiler Operating at 75% Reduced Nominal Load**	**Boiler Operating at 100% Nominal Load**	
Criteria Pollutants		(%)	(lb/hr)	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**	**(lb/hr)**	
NOx		60%	150.95	**2.44**	**42.30**	**70.80**	**105.90**	**141.30**	As guaranteed by vendor with SCR.
SO_2		92%	106.16	**0.04**	**29.94**	**50.11**	**74.95**	**100.00**	
CO		0%	110.04	**2.44**	**31.02**	**51.92**	**77.66**	**103.62**	
VOC		70%	2.55	**0.33**	**2.40**	**1.20**	**1.80**	**2.40**	
PM	Filterable	99.8%	7.27	**0.11**	**2.05**	**3.43**	**5.13**	**6.85**	
PM_{10}	Filterable	99.8%	6.49	**0.11**	**1.83**	**3.06**	**4.58**	**6.11**	
$PM_{2.5}$	Filterable	99.8%	5.58	**0.11**	**1.57**	**2.63**	**3.94**	**5.26**	
PM	Condensible	0%	8.50	**0.34**	**2.40**	**4.01**	**6.00**	**8.01**	
PM_{10}	Condensible	0%	8.50	**0.34**	**2.40**	**4.01**	**6.00**	**8.01**	
$PM_{2.5}$	Condensible	0%	8.50	**0.34**	**2.40**	**4.01**	**6.00**	**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**	**25,222**	**50,877**	**76,099**	**101,538**	
CH_4		0%	35.28	**0.01**	**0.48**	**16.65**	**24.91**	**33.23**	
N_2O		0%	4.63	**0.00**	**0.05**	**2.19**	**3.27**	**4.36**	

Appendix B

Nearby Source Inventory Used for Revised 1-Hour NO_2 NAAQS Analysis

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

NOx Nearby Source Parameters and Emissions

KANSAS NEARBY SOURCES

Model ID	Facility ID	Facility Name	Source Description	UTM Zone	X Coordinate (m)	Y Coordinate (m)	Elevation (m)	Distance from Facility (km)	Stack Height (ft)	Stack Gas Temperature (°F)	Stack Exit Velocity (ft/s)	Stack Diameter (ft)	NOx Emissions PTE (lbs/hr)	NO_2/NOx Ratio
KSNO418	1890103	SEABOARD FOODS, LP 001	External Combustion Boilers, Grades 1 and 2 O	14	288569	4116475	952.47	0.41	73.607	416.636	29.334	3.781	2.057	0.05
KSNO436	1890203	CITY OF HUGOTON	NG Engine	14	290764	4116301	950.32	2.42	28.761	704.857	55.021	1.618	7.815	0.10
KSNO423	1890143	ANADARKO GATHERING COMPANY LLC 1	NG Engine	14	285864	4115896	961.66	2.72	16.000	1175.270	157.000	0.830	3.965	0.10
KSNO424	1890143	ANADARKO GATHERING COMPANY LLC 1	NG Engine	14	285864	4115896	961.66	2.72	16.000	1175.270	157.000	0.830	47.180	0.10
KSNO421	1890136	ANADARKO GATHERING COMPANY LLC 4	NG Engine	14	287584	4119492	958.41	2.77	20.000	1105.270	198.000	0.670	4.097	0.10
KSNO375	1890020	HUGOTON MUNICIPAL POWER PLANT (#1)	Dual Fuel Engine	14	291552	4117045	948.18	3.15	28.761	704.857	55.021	1.618	16.785	0.29
KSNO435	1890202	CITY OF HUGOTON	NG Engine	14	291578	4116896	947.94	3.17	28.761	704.857	55.021	1.618	3.294	0.10
KSNO434	1890201	ONEOK FIELD SERVICES COMPANY, L.L.C.	NG Engine	14	286706	4113812	961.92	3.48	28.761	704.857	55.021	1.618	2.551	0.10
KSNO420	1890126	ANADARKO GATHERING COMPANY LLC	NG Engine	14	291615	4118513	947.75	3.61	28.761	704.857	55.021	1.618	4.002	0.10
KSNO437	1890208	ONEOK FIELD SERVICES COMPANY, L.L.C.	NG Engine	14	290045	4120184	953.82	3.71	28.761	704.857	55.021	1.618	5.103	0.10
KSNO376	1890021	HUGOTON MUNICIPAL POWER PLANT (#2)	Internal Combustion Engines, Dual Fuel (Oil/G	14	292326	4115396	947.24	4.18	33.000	505.270	106.400	2.500	474.504	0.21
KSNO438	1890209	ONEOK FIELD SERVICES COMPANY, L.L.C.	NG Engine	14	288265	4112165	963.19	4.69	28.761	704.857	55.021	1.618	3.894	0.10
KSNO366	1890015	ANADARKO GATHERING COMPANY LLC 18	4.00 GLYCOL REBOILER	14	293191	4115298	947.66	5.03	20.000	1000.270	484.000	1.000	0.107	0.05
KSNO357	1890015	ANADARKO GATHERING COMPANY LLC 1	NG Engine	14	293191	4115298	947.66	5.03	32.000	660.270	149.000	0.830	29.543	0.10
KSNO358	1890015	ANADARKO GATHERING COMPANY LLC 10	NG Engine	14	293191	4115298	947.66	5.03	35.000	660.270	149.000	0.830	29.543	0.10
KSNO359	1890015	ANADARKO GATHERING COMPANY LLC 11	NG Engine	14	293191	4115298	947.66	5.03	45.000	660.270	94.000	2.000	138.269	0.10
KSNO360	1890015	ANADARKO GATHERING COMPANY LLC 12	NG Engine	14	293191	4115298	947.66	5.03	45.000	660.270	94.000	2.000	138.269	0.10
KSNO361	1890015	ANADARKO GATHERING COMPANY LLC 13	NG Engine	14	293191	4115298	947.66	5.03	45.000	660.270	94.000	2.000	138.269	0.10
KSNO362	1890015	ANADARKO GATHERING COMPANY LLC 14	NG Engine	14	293191	4115298	947.66	5.03	45.000	660.270	80.000	3.000	205.460	0.10
KSNO363	1890015	ANADARKO GATHERING COMPANY LLC 15	NG Engine	14	293191	4115298	947.66	5.03	20.000	1100.270	240.000	0.500	9.362	0.10
KSNO364	1890015	ANADARKO GATHERING COMPANY LLC 16	NG Engine	14	293191	4115298	947.66	5.03	20.000	1100.270	240.000	0.500	9.362	0.10
KSNO365	1890015	ANADARKO GATHERING COMPANY LLC 17	Diesel Engine	14	293191	4115298	947.66	5.03	12.000	1100.270	39.000	0.500	28.866	0.10
KSNO367	1890015	ANADARKO GATHERING COMPANY LLC 2	NG Engine	14	293191	4115298	947.66	5.03	32.000	660.270	150.000	0.830	29.543	0.10
KSNO368	1890015	ANADARKO GATHERING COMPANY LLC 3	NG Engine	14	293191	4115298	947.66	5.03	32.000	660.270	149.000	0.830	29.543	0.10
KSNO369	1890015	ANADARKO GATHERING COMPANY LLC 4	NG Engine	14	293191	4115298	947.66	5.03	35.000	660.270	149.000	0.830	29.543	0.10
KSNO370	1890015	ANADARKO GATHERING COMPANY LLC 5	NG Engine	14	293191	4115298	947.66	5.03	35.000	660.270	149.000	0.830	29.543	0.10
KSNO371	1890015	ANADARKO GATHERING COMPANY LLC 6	NG Engine	14	293191	4115298	947.66	5.03	35.000	660.270	149.000	0.830	29.543	0.10
KSNO372	1890015	ANADARKO GATHERING COMPANY LLC 7	NG Engine	14	293191	4115298	947.66	5.03	35.000	660.270	149.000	0.830	29.543	0.10
KSNO373	1890015	ANADARKO GATHERING COMPANY LLC 8	NG Engine	14	293191	4115298	947.66	5.03	35.000	660.270	149.000	0.830	29.543	0.10
KSNO374	1890015	ANADARKO GATHERING COMPANY LLC 9	NG Engine	14	293191	4115298	947.66	5.03	35.000	660.270	149.000	0.830	29.543	0.10
KSNO412	1890054	WTG HUGOTON, LP 1	NG Engine	14	290087	4121793	961.44	5.22	21.000	650.270	64.300	1.000	31.111	0.10
KSNO413	1890054	WTG HUGOTON, LP 2	NG Engine	14	290087	4121793	961.44	5.22	21.000	650.270	64.100	1.000	31.111	0.10
KSNO414	1890054	WTG HUGOTON, LP 3	NG Engine	14	290087	4121793	961.44	5.22	21.000	650.270	64.100	1.000	31.111	0.10
KSNO415	1890054	WTG HUGOTON, LP 4	NG Engine	14	290087	4121793	961.44	5.22	21.000	650.270	64.100	1.000	31.111	0.10
KSNO345	1890008	WTG HUGOTON, LP	NG Engine	14	293270	4120091	949.39	5.61	17.000	800.000	116.900	0.660	0.039	0.10
KSNO351	1890009	WTG HUGOTON, LP	NG Engine	14	293270	4120091	949.39	5.61	17.000	800.000	118.300	0.660	0.029	0.10
KSNO352	1890010	WTG HUGOTON, LP	NG Engine	14	293270	4120091	949.39	5.61	23.000	800.000	66.800	1.330	129.059	0.10
KSNO353	1890011	WTG HUGOTON, LP	NG Engine	14	293270	4120091	949.39	5.61	25.000	800.000	112.400	1.160	3.295	0.10
KSNO354	1890012	WTG HUGOTON, LP	NG Engine	14	293270	4120091	949.39	5.61	23.000	800.000	77.200	1.330	132.694	0.10
KSNO430	1890183	ONEOK FIELD SERVICES COMPANY, L.L.C.	NG Engine	14	283492	4113897	969.29	5.74	28.761	704.857	55.021	1.618	15.386	0.10
KSNO346	1890009	WTG HUGOTON, LP 1	NG Engine	14	293270	4120091	949.39	5.84	17.000	800.270	116.900	0.660	9.793	0.10
KSNO347	1890009	WTG HUGOTON, LP 2	NG Engine	14	293270	4120091	949.39	5.84	17.000	800.270	118.300	0.660	9.793	0.10
KSNO348	1890009	WTG HUGOTON, LP 4	COOPER-BESSEMER GMVA-10	14	293270	4120091	949.39	5.84	23.000	800.270	66.800	1.330	35.559	0.10
KSNO349	1890009	WTG HUGOTON, LP 5	NG Engine	14	293270	4120091	949.39	5.84	25.000	800.270	112.400	1.160	26.775	0.10

KANSAS NEARBY SOURCES														
Model ID	Facility ID	Facility Name	Source Description	UTM Zone	X Coordinate (m)	Y Coordinate (m)	Elevation (m)	Distance from Facility (km)	Stack Height (ft)	Stack Gas Temperature (°F)	Stack Exit Velocity (ft/s)	Stack Diameter (ft)	NOx Emissions PTE (lbs/hr)	NO_2/NOx Ratio
KSNO350	1890009	WTG HUGOTON, LP 6	COOPER-BESSEMER GMVA-10	14	293270	4120091	949.39	5.84	23.000	800.270	77.200	1.330	35.559	0.10
KSNO431	1890185	ONEOK FIELD SERVICES COMPANY, LLC 00	NG Engine	14	288858	4123068	965.41	6.23	24.512	814.583	53.826	1.087	10.720	0.10
KSNO425	1890144	ANADARKO GATHERING COMPANY LLC 1	NG Engine	14	287384	4110614	963.31	6.32	16.000	1100.270	148.000	0.830	49.162	0.10
KSNO396	1890044	ANADARKO GATHERING COMPANY LLC	NG Engine	14	282561	4114129	971.19	6.45	24.512	814.583	53.826	1.087	4.438	0.10
KSNO397	1890044	ANADARKO GATHERING COMPANY LLC	NG Engine	14	282561	4114129	971.19	6.45	24.512	814.583	53.826	1.087	7.490	0.10
KSNO398	1890044	ANADARKO GATHERING COMPANY LLC	NG Engine	14	282561	4114129	971.19	6.45	24.512	814.583	53.826	1.087	4.438	0.10
KSNO399	1890044	ANADARKO GATHERING COMPANY LLC	NG Engine	14	282561	4114129	971.19	6.45	20.000	1103.270	230.000	1.000	13.107	0.10
KSNO422	1890137	ANADARKO GATHERING COMPANY LLC	NG Engine	14	282035	4120385	967.86	7.29	28.761	704.857	55.021	1.618	21.409	0.10
KSNO432	1890189	ANADARKO GATHERING COMPANY LLC 1	NG Engine	14	287016	4124348	962.65	7.63	16.000	1105.270	111.000	0.830	38.590	0.10
KSNO440	1890220	ANADARKO GATHERING COMPANY LLC	NG Engine	14	281622	4113136	973.81	7.74	28.761	704.857	55.021	1.618	2.551	0.10
KSNO386	1890025	WTG HUGOTON, LP	NG Engine	14	293047	4110431	950.08	7.92	24.512	814.583	53.826	1.087	7.003	0.10
KSNO387	1890025	WTG HUGOTON, LP 1	NG Engine	14	293047	4110431	950.08	7.92	17.000	800.270	64.700	1.330	35.559	0.10
KSNO388	1890025	WTG HUGOTON, LP 2	NG Engine	14	293047	4110431	950.08	7.92	16.000	800.270	109.800	1.000	23.105	0.10
KSNO389	1890025	WTG HUGOTON, LP 3	NG Engine	14	293047	4110431	950.08	7.92	15.000	800.270	69.300	0.830	10.972	0.10
KSNO390	1890025	WTG HUGOTON, LP 5	NG Engine	14	293047	4110431	950.08	7.92	19.000	800.270	71.300	0.660	14.305	0.10
KSNO391	1890025	WTG HUGOTON, LP 6	NG Engine	14	293047	4110431	950.08	7.92	19.000	800.270	71.300	0.660	7.003	0.10
KSNO392	1890025	WTG HUGOTON, LP 7	NG Engine	14	293047	4110431	950.08	7.92	19.000	800.270	71.300	0.660	7.003	0.10
KSNO393	1890032	WTG HUGOTON, LP 1	NG Engine	14	283401	4110674	977.16	7.95	17.000	800.270	171.100	0.830	19.922	0.10
KSNO394	1890032	WTG HUGOTON, LP 2	NG Engine	14	283401	4110674	977.16	7.95	23.000	800.270	87.100	1.160	29.543	0.10
KSNO395	1890032	WTG HUGOTON, LP 3	NG Engine	14	283401	4110674	977.16	7.95	18.000	800.270	131.700	1.160	55.308	0.10
KSNO419	1890115	EXXONMOBIL PRODUCTION COMPANY	NG Engine	14	280359	4117196	968.32	8.06	28.761	704.857	55.021	1.618	1.209	0.10
KSNO429	1890182	ONEOK FIELD SERVICES COMPANY, LLC	NG Engine	14	286578	4108981	967.51	8.08	28.761	704.857	55.021	1.618	30.237	0.10
KSNO427	1890176	ONEOK FIELD SERVICES COMPANY, L.L.C.	NG Engine	14	293903	4109558	949.42	9.13	24.512	814.583	53.826	1.087	1.429	0.10
KSNO428	1890180	ONEOK FIELD SERVICES COMPANY, L.L.C.	NG Engine	14	294956	4123273	952.70	9.17	28.761	704.857	55.021	1.618	16.822	0.10
KSNO439	1890213	ONEOK FIELD SERVICES COMPANY, L.L.C.	NG Engine	14	280465	4122038	971.83	9.49	28.761	704.857	55.021	1.618	5.612	0.10
KSNO426	1890166	ONEOK FIELD SERVICES COMPANY, L.L.C.	NG Engine	14	288600	4126680	960.68	9.83	28.761	704.857	55.021	1.618	8.729	0.10
KSNO356	1890014	ANADARKO GATHERING COMPANY LLC 00	GLYCOL REBOILER	14	284905	4105801	972.43	11.59	20.000	600.270	26.000	0.830	0.196	0.05
KSNO355	1890014	ANADARKO GATHERING COMPANY LLC 00	NG Engine	14	284905	4105801	972.43	11.59	35.000	660.270	43.000	3.000	85.944	0.10
KSNO403	1890051	ANADARKO GATHERING COMPANY LLC	GLYCOL DEHY REBOILER	14	275641	4120558	980.02	13.30	27.150	510.018	18.245	1.607	0.196	0.05
KSNO404	1890051	ANADARKO GATHERING COMPANY LLC 1	NG Engine	14	275641	4120558	980.02	13.30	42.000	805.270	183.700	1.330	91.603	0.10
KSNO405	1890051	ANADARKO GATHERING COMPANY LLC 2	NG Engine	14	275641	4120558	980.02	13.30	42.000	805.270	183.000	1.330	91.603	0.10
KSNO406	1890051	ANADARKO GATHERING COMPANY LLC 3	NG Engine	14	275641	4120558	980.02	13.30	42.000	805.270	183.700	1.330	91.603	0.10
KSNO407	1890051	ANADARKO GATHERING COMPANY LLC 4	NG Engine	14	275641	4120558	980.02	13.30	42.000	805.270	183.000	1.330	91.603	0.10
KSNO408	1890051	ANADARKO GATHERING COMPANY LLC 5	NG Engine	14	275641	4120558	980.02	13.30	42.000	805.270	183.000	1.330	91.603	0.10
KSNO409	1890051	ANADARKO GATHERING COMPANY LLC 6	NG Engine	14	275641	4120558	980.02	13.30	42.000	805.270	183.000	1.330	91.603	0.10
KSNO410	1890051	ANADARKO GATHERING COMPANY LLC 7	NG Engine	14	275641	4120558	980.02	13.30	14.000	1100.270	383.000	0.500	4.106	0.10
KSNO411	1890051	ANADARKO GATHERING COMPANY LLC 8	CATERPILLAR D349, 1100HP	14	275641	4120558	980.02	13.30	16.000	1100.270	168.000	0.830	29.543	0.10
KSNO400	1890046	WTG HUGOTON, LP 1	NG Engine	14	306223	4124605	930.30	19.43	18.000	800.270	65.100	1.160	38.024	0.10
KSNO401	1890046	WTG HUGOTON, LP 2	NG Engine	14	306223	4124605	930.30	19.43	18.000	800.270	65.000	1.160	38.024	0.10
KSNO402	1890046	WTG HUGOTON, LP 3	NG Engine	14	306223	4124605	930.30	19.43	23.000	850.270	104.600	0.830	15.447	0.10
KSNO319	1890008	WTG HUGOTON, LP	BOILER FOR TANK 7	14	307729	4119753	911.72	19.54	27.150	510.018	18.245	1.607	0.024	0.05
KSNO320	1890008	WTG HUGOTON, LP 1	NG Engine	14	307729	4119753	911.72	19.54	27.000	765.270	30.900	1.830	23.105	0.10
KSNO321	1890008	WTG HUGOTON, LP 10	NG Engine	14	307729	4119753	911.72	19.54	27.000	765.270	31.800	1.830	23.105	0.10
KSNO322	1890008	WTG HUGOTON, LP 11	NG Engine	14	307729	4119753	911.72	19.54	27.000	765.270	31.800	1.830	23.105	0.10
KSNO326	1890008	WTG HUGOTON, LP 15	NG Engine	14	307729	4119753	911.72	19.54	29.000	650.270	45.800	1.660	48.343	0.10
KSNO327	1890008	WTG HUGOTON, LP 16	NG Engine	14	307729	4119753	911.72	19.54	27.000	650.270	31.600	2.000	48.343	0.10
KSNO328	1890008	WTG HUGOTON, LP 17	NG Engine	14	307729	4119753	911.72	19.54	27.000	650.270	31.600	2.000	48.343	0.10
KSNO329	1890008	WTG HUGOTON, LP 18	NG Engine	14	307729	4119753	911.72	19.54	21.000	500.270	83.000	1.000	37.506	0.10
KSNO330	1890008	WTG HUGOTON, LP 19	NG Engine	14	307729	4119753	911.72	19.54	21.000	500.270	83.000	1.000	37.506	0.10
KSNO331	1890008	WTG HUGOTON, LP 2	NG Engine	14	307729	4119753	911.72	19.54	27.000	765.270	31.200	1.830	23.105	0.10
KSNO332	1890008	WTG HUGOTON, LP 20	NG Engine	14	307729	4119753	911.72	19.54	21.000	500.270	83.000	1.000	37.506	0.10

KANSAS NEARBY SOURCES														
Model ID	Facility ID	Facility Name	Source Description	UTM Zone	X Coordinate (m)	Y Coordinate (m)	Elevation (m)	Distance from Facility (km)	Stack Height (ft)	Stack Gas Temperature (°F)	Stack Exit Velocity (ft/s)	Stack Diameter (ft)	NOx Emissions PTE (lbs/hr)	NO_2/NOx Ratio
KSNO333	1890008	WTG HUGOTON, LP 21	NG Engine	14	307729	4119753	911.72	19.54	14.000	500.270	66.500	0.660	7.639	0.10
KSNO334	1890008	WTG HUGOTON, LP 22	NG Engine	14	307729	4119753	911.72	19.54	14.000	500.270	66.500	0.660	7.639	0.10
KSNO335	1890008	WTG HUGOTON, LP 23	NG Engine	14	307729	4119753	911.72	19.54	14.000	500.270	66.500	0.660	7.639	0.10
KSNO336	1890008	WTG HUGOTON, LP 24	NG Engine	14	307729	4119753	911.72	19.54	13.000	800.270	79.500	0.660	7.021	0.10
KSNO337	1890008	WTG HUGOTON, LP 25	NG Engine	14	307729	4119753	911.72	19.54	13.000	800.270	79.500	0.660	7.021	0.10
KSNO338	1890008	WTG HUGOTON, LP 3	NG Engine	14	307729	4119753	911.72	19.54	27.000	765.270	31.200	1.830	23.105	0.10
KSNO339	1890008	WTG HUGOTON, LP 4	NG Engine	14	307729	4119753	911.72	19.54	27.000	765.270	31.200	1.830	23.105	0.10
KSNO340	1890008	WTG HUGOTON, LP 5	NG Engine	14	307729	4119753	911.72	19.54	27.000	765.270	31.800	1.830	23.105	0.10
KSNO341	1890008	WTG HUGOTON, LP 6	NG Engine	14	307729	4119753	911.72	19.54	27.000	765.270	31.800	1.830	23.105	0.10
KSNO342	1890008	WTG HUGOTON, LP 7	NG Engine	14	307729	4119753	911.72	19.54	27.000	765.270	31.800	1.830	23.105	0.10
KSNO343	1890008	WTG HUGOTON, LP 8	NG Engine	14	307729	4119753	911.72	19.54	27.000	765.270	31.800	1.830	23.105	0.10
KSNO344	1890008	WTG HUGOTON, LP 9	NG Engine	14	307729	4119753	911.72	19.54	27.000	765.270	31.800	1.830	23.105	0.10
KSNO323	1890008	WTG HUGOTON, LP 12	SOLAR T1001S332	14	307729	4119753	911.72	19.54	22.000	850.270	55.600	1.500	2.928	0.25
KSNO324	1890008	WTG HUGOTON, LP 13	SOLAR T1001S332	14	307729	4119753	911.72	19.54	22.000	850.270	55.600	1.500	2.928	0.25
KSNO325	1890008	WTG HUGOTON, LP 14	SOLAR T1001S332	14	307729	4119753	911.72	19.54	22.000	850.270	55.600	1.500	2.928	0.25
KSNO318	1890008	WTG HUGOTON, LP	DEHY VRU VENT PILOT	14	307729	4119753	911.72	19.54	20.740	553.249	11.501	1.087	0.764	0.50

Appendix C

AERMOD Input/Output Files, Support Files and Readme File

readme.txt
Abengoa Bioenergy Biomass of Kansas, LLC
Biorefinery Facility
Hugoton, Kansas

August 2011

Appendix C Read Me

C1. File Nomenclature

Each of the AERMOD input / output modeling files contained on the enclosed DVD has been named using the following methodology:
FAC_POL-AMB_AVE_YEAR_RUN_REV_Description_PART
Where:
FAC = Identifier for the proposed facility: ABBK (Abengoa Bioenergy Biomass of Kansas)
POL = Pollutant ID: NO2
AMB = Ambient concentrations evaluation: significant impact levels (SIL) or National Ambient Air Quality Standard (NAAQS)
AVE = Averaging period: 1-hour (1-HR)
YEAR = Year of meteorological data used: 2006 to 2010
RUN = Run number: Run2 (SCR Emission Rate)
REV = Revision number from original June 2011 AQIA (Rev1)
PART = Partition number, P1 is H1H thru H50H, P2 is H51H thru H100H, P3 is H101 thru H150H, and P4 is H151 thru H200H
Description = Boiler load scenario modeled
Where:

1. AB500 Scenario includes the Boiler at 500 MMBtu/hr, Flare Operational and No Firewater Pump.
3. AB471 Scenario includes the Boiler at 471 MMBtu/hr, Flare Operational and No Firewater Pump.
4. AB353 Scenario includes the Boiler at 353 MMBtu/hr, Flare Operational and No Firewater Pump.
5. AB236 Scenario includes the Boiler at 236 MMBtu/hr, Flare Operational and No Firewater Pump.
6. AB141 Scenario includes the Boiler at 141 MMBtu/hr, Flare Operational and No Firewater Pump.

For cumulative model runs, the NAQ source groups were used for all sources, including the facility and nearby sources. The Nearby source groups were used for nearby sources only.

C2. DVDs Table of Contents

There are three DVDs included with this report. The following details the Table of Contents for each disk.

DISK ONE

AB_AQIA_08-2011_DISK1
This folder contains the AERMOD input / output files for 1-hour NO2; as well as the support files for these runs and the AQIA supplement report and appendices.

The Disk 1 subfolders are as follows:

1. 1-HOUR_NO2_Rev1
This folder contains the corresponding input / output files for the pollutant and averaging period indicated.
2. MET DATA
This folder contains the meteorological files used for the model runs.

3. NEARBY
This folder contains the nearby source data used in the 1-hour NO2 NAAQS analysis.
4. OZONE
This folder contains the ozone file used in the 1-hour NO2 NAAQS analysis.
5. PROTOCOL
This folder contains the April 2011 protocol, June 2011 protocol memo, and KDHE comments and correspondences regarding the modeling parameters and procedures.
6. AQIA Supplement Report Rev0
This folder contains the final AQIA supplement report and appendices.