BURNS McDONNELL

June 22, 2015

Mindy Bowman
Kansas Department of Health and Environment
Bureau of Air and Radiation
1000 SW Jackson, Suite 310
Topeka, KS 66612-1366

Re: PSD Modification at Abengoa Bioenergy Biomass of Kansas, LLC – Source ID 1890231

Dear Ms. Bowman:

A Prevention of Significant Deterioration (PSD) air construction permit application associated with a modification at an existing facility was submitted in March 2015 by Abengoa Bioenergy Biomass of Kansas, LLC (ABBK) -Source ID 1890231. This facility is a major source of HAPS and a major source PSD program. The facility is located in Stevens County, Kansas. The $5,500 permit application fee was previously submitted.

This letter serves as an addendum to the application and to provide additional information.

Rental Boiler

As was discussed,[1] ABBK wants to add a 96.6 MMBtu/hr natural gas-fired rental boiler at the facility to aid in steam production until the starter boiler is constructed. The rental boiler would not operate at the same time as the starter boiler. Air dispersion modeling was conducted for compliance with the National Ambient Air Quality Standards (NAAQS) for 1-hour NO_2 for two operating conditions, as shown in Table 1. The model used was identical to the model submitted in March 2015 for the PSD application except for the addition of the rental boiler. Modeling files will be sent via email.

Table 1 shows that although there are modeled NAAQS 1-hour NO_2 exceedances, the contribution from ABBK is less than the Kansas 1-hour NO_2 significance rate of 10 $\mu g/m^3$.

[1] May 11, 2015 email from Marian Massoth (KDHE) to Brent Inkelaar (ABBK); multiple emails between Robynn Andracsek (Burns & McDonnell) and Mindy Bowman (KDHE) (Jun 16, 2015 – June 18, 2015)

Table 1: NO_2 1-hour Modeling Scenarios and Results

Scenario	Highest 1-hour NO_2 NAAQS Contribution ($\mu g/m^3$)	Highest Contribution from ABBK at an Exceedance ($\mu g/m^3$)
Rental boiler at full load; biomass boiler off	2,033.84	2.83
Rental boiler at standby load; biomass boiler at 477 MMBtu/hr	2,033.84	8.18

Application forms are attached to this letter and include the stack parameters for the rental boiler. See Attachment A. Forms with original signatures will follow under separate cover.

The rental boiler will comply with New Source Performance Standards (40 CFR 60 Subpart Dc) and National Emissions Standards for Hazardous Air Pollutants (40 CFR 63 Subpart DDDDD).

BACT for EP-0150 and EP-11000

ABBK would like to clarify the BACT information regarding EP-11000 and EP-01050, Biomass Storage and Handling, which were changes to existing sources. Although there are some design changes, the Best Available Control Technology (BACT) analysis will not change for EP-11000 and EP-01050 and will remain the same as in the BACT section of the previous application.

BACT for EP-0150

In the previous application, BACT for EP-0150, overnight trailer area, was inadvertently omitted. It should have been included in Section 6.4 – BACT for Particulate Matter – Material Handling Fugitives. See Attachment B for the revised BACT section.

Overflow and Recycle Conveyor (FUG-OFRC)

Potential throughput (worst-case) at the overflow and recycle conveyor is increasing to 500 tons per day. Nothing is being modifying upstream. This worst case scenario reflects if the solid fuel is completely bypassing the boiler and passing through the overflow chute, which would not happen very frequently or for any significant duration. Normally, 95% of the flow goes to the boiler as fuel and only 5% carries over in the overflow chute. See Attachment B for the revised BACT section.

ATTACHMENT A – KDHE FORMS

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: [X]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: 1890231

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

3) Source Location:
   Street Address: N/A.
   City, County, State, Zip: Hugoton, Stevens, Kansas 67951.
   Section, Township, Range: Section 18, Township 33S, Range 37W.
   Latitude & Longitude Coordinates: UTM: 288420.00 Easting, 4117545.00 Northing

4) NAICSC/SIC Code (Primary): 325193/2869

5) Primary Product Produced at the Source: Ethanol

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

   If no, please explain:

7) Is a permit fee being submitted? [X]Yes [ ]No

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

8) Person to Contact at the Site: Brent Inkelaar Phone: (812) 760-2201
   Title: QSE Manager, Abengoa Bioenergy Biomass of Kansas
   Email: Brent.Inkelaar@abengoa.com Fax: (636) 544-7791

9) Person to Contact Concerning Permit: Brent Inkelaar Phone: (812) 760-2201
   Title: QSE Manager, Abengoa Bioenergy Biomass of Kansas
   Email: Brent.Inkelaar@abengoa.com Fax: (636) 544-7791

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 : Craig Kramer Executive Vice President

Address: : 16150 Main Circle Drive, Suite 300 Chesterfield, Missouri, 63017

Signature: ______________________ Date: ___/___/_____ Phone: (636) 728-0508

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

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**	$ 8,000,000+
Multiply by .05% (.0005)		x .0005
Total	**Line 2**	$ 4000
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**	$ 5,500 Paid for with the pending application Minimum fee is $100

Craig Kramer
(Print)

Certifier of Capital Cost

(Signature) 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.

Kansas Department of Health and Environment
Division of Environment
Bureau of Air and Radiation

INDIRECT HEATING UNIT (BOILER)

1) Source ID Number: ____1890231_____

2) Company/Source Name: ____________Abengoa Bioenergy Biomass of Kansas, LLC

3) Emission Unit Identification:____TEMPBOIL1

4) Manufacturer:_____Natcom__________________Model No.:____ CB-NATCOM LOW NOX

5) Maximum design heat-input rate: _______96.6_MM__________ BTU/hr
   Heat-release Rate: ______ BTU/hr/cu. ft. of furnace volume
   Annual load factor: ______
   Heater design: Cyclone ______; Underfeed stoker ______; Spreader stoker ______;
   Pulverized (dry-tangential or normal/wet)______; Other (specify) _______________
   Normal Operating Schedule: _8760_____ hours/year
   Date of latest modification: ________________

6) Primary Fuel Type:
   Natural Gas _X___ Oil ____Coal ____ Other (specify) ____________________
   Secondary Fuel Type:
   Natural Gas ____ Oil ____ Coal ____ Other (specify) ____________________

7) If other fuel is waste liquid:
   What is the source of the waste? ____
   Will the waste be pretreated to remove any of the contaminants? Yes ____; No ____ If yes, describe method of pretreatment:

   ____

   ____

   If waste liquid is used in combination with fuel oil:
   Specify the volume percent of waste liquid:______ %
   Specify the anticipated annual operating hours during which the fuel and waste combination will be used: ______ hrs.
   Fill in the data below for the fuel oil.

Include the chemical and physical characteristics of the waste liquid. Also, include any source emissions test data that is available from testing similar facilities that have disposed of this type liquid waste.

INDIRECT HEATING UNIT (BOILER)
(cont.)

8) Fuel Specific Data: (if other is specified, give appropriate data)
Natural Gas:
Heating value: ___1,020________ BTU/cu. ft.
(If fuel gas is used, also specify %Sulfur: _____)
Coal:
Fuel Parameters: %Sulfur: _____ % Ash: ________
Heating value: __________ BTU/lb.
Fuel Oil:
Fuel Parameters: %Sulfur: ____ Grade: ________
Heating value: ___________ BTU/gal.
Density: ___________ lb./gal.

9) Air Emissions Control Technology: NOx _X___ SOx ____ CO ____ Particulate ____
If yes, breakdown of Control Technology:___Low Nox Burners

10) Soot blowing (if applicable): frequency: ________ duration: ________

11) Has boiler been derated because of:
Fuel change __________ Equip. limitations ____________ Regulatory compliance ______________

12) Emissions discharge to atmosphere __24___ ft. above grade through stack or duct __4___ ft. diameter at __ 457 __ E F temperature, with __ 81,355 ___ cfm flow rate and ___ 107.9 __ fps velocity.

13) For emission control equipment, use the appropriate CONTROL EQUIPMENT form and duplicate as needed. Be sure to indicate the emission unit that the control equipment is affecting

14) Did construction, modification, or reconstruction commence after August 17, 1971 and on or before September 18, 1978 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 250 million BTU/hour? Yes ______; No___X___
If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart D.

15) Did construction, modification, or reconstruction commence after September 18, 1978 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 250 million BTU/hour? Yes ______; No__X____
If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Da.

16) Did construction, modification, or reconstruction commence after June 19, 1984 and does the indirect heating unit have a maximum design heat-input capacity to combust more than 100 million BTU/hour but less than 250 million BTU/hour? Yes ______; No__X____
If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Db.

INDIRECT HEATING UNIT (BOILER)
(cont.)

17) Did construction, modification, or reconstruction commence after June 9, 1989 and does the indirect heating unit have a maximum design heat-input capacity to combust 10 million or more BTU/hour but less than 100 million BTU/hour? Yes ___X___; No______

If yes, this plant may be subject to NSPS, 40 CFR Part 60, Subpart Dc.

CB-NATCOM LOW NOX BURNER PERFORMANCE SUMMARY

	Fuel = "Natural Gas"	Oil_No = 2
Burner Heat input (HHV):	$Heatinput_{gas} = 96.6 \cdot \frac{MMBTU}{hr}$	$Heatinput_{oil} = 92.4 \cdot \frac{MMBTU}{hr}$
Burner Heat input (LHV):	$Heatinput_{gas\_LHV} = 87 \cdot \frac{MMBTU}{hr}$	$Heatinput_{oil\_LHV} = 87 \cdot \frac{MMBTU}{hr}$
Flame Length :	$L_{fl\_gas} = 16.8 \cdot ft$	$L_{oil\_flame} = 19.7 \cdot ft$
Flame Diameter :	$D_{fl\_gas} = 4.8 \cdot ft$	$D_{oil\_flame} = 5.5 \cdot ft$
Turndown ratio :	$Turndown_{gas} = 10$	$Turndown_{oil} = 8$
Fuel flow at full load: *1 - Flows and fuel heating values are given in wet basis 2 - SCF are at 60°F and 1 atm*	$m_{gas} = 4431 \cdot \frac{lb}{hr}$	$m_{oil} = 4752 \cdot \frac{lb}{hr}$
	$Q_{gas\_std} = 96968 \cdot SCFH$	$Q_{oil\_std} = 10.7 \cdot \frac{USgal}{min}$
Fuel heating value: *1 - Flows and fuel heating values are given in wet basis 2 - SCF are at 60°F and 1 atm*	$HHV_{gas\_std} = 996.2 \cdot \frac{BTU}{SCF}$	$HHV_{oil} \cdot \rho_{oil\_std} = 143970 \cdot \frac{BTU}{USgal}$
	$LHV_{gas\_std} = 899 \cdot \frac{BTU}{SCF}$	$LHV_{oil} \cdot \rho_{oil\_std} = 134842 \cdot \frac{BTU}{USgal}$
Fuel pressure at full load : (Pressure at burner gas ring inlet)	$P_{gas} = 12 \cdot psi$	$P_{oil} = 100 \cdot psi$
Combustion air (+FGR) flow at full load (@ operating conditions) :	$M_{a\_gas\_o} = 93866 \cdot \frac{lb}{hr}$	$M_{a\_oil\_o} = 91474 \cdot \frac{lb}{hr}$

Combustion air volumetric Flows:

With FGR at full load (@ operating conditions):	$Q_{a\_gas\_o} = 25934 \cdot ACFM$	$Q_{a\_oil\_o} = 25165 \cdot ACFM$
Without FGR at full load (@ operating conditions):	$Q_{FA\_gas\_o} = 20014 \cdot ACFM$	$Q_{FA\_oil\_o} = 19490 \cdot ACFM$
Maximum and minimum with FGR:		
At full load (@ maximum conditions):	$Q_{a\_gas\_max} = 26977 \cdot ACFM$	$Q_{a\_oil\_max} = 26177 \cdot ACFM$
At turndown (@ minimum conditions):	$Q_{a\_gas\_min} = 2633 \cdot ACFM$	$Q_{a\_oil\_min} = 3252 \cdot ACFM$
Maximum and minimum without FGR:		
At full load (@ maximum conditions):	$Q_{FA\_gas\_max} = 21027 \cdot ACFM$	$Q_{FA\_oil\_max} = 20476 \cdot ACFM$
At turndown (@ minimum conditions):	$Q_{FA\_gas\_min} = 2054 \cdot ACFM$	$Q_{FA\_oil\_min} = 2545 \cdot ACFM$

Atomizing steam flow at full load :	$m_{steam\_atom} = 475 \cdot \frac{lb}{hr}$
Atomizing steam pressure at full load : (Pressure at burner coupling block)	$P_{atom\_steam} = 110 \cdot psi$

CB-NATCOM BURNER PREDICTED EMISSIONS PERFORMANCE SUMMARY

Fuel, Air & FGR :

$Fuel = $ "Natural Gas" $\quad Oil\_No = 2 \quad N_{fuel} = 0.02 \cdot \%$

$EA_{gas} = 15 \cdot \% \quad FGR_{gas} = 15 \cdot \% \quad EA_{oil} = 15 \cdot \% \quad FGR_{oil} = 15 \cdot \%$

NOx :

$Factor_{ng} := 1.2 \quad Factor_{no} := 0.9$

$NOx_{gas} \cdot Factor_{ng} = 27.21 \cdot ppm \quad NOx_{oil} \cdot Factor_{no} = 76.02 \cdot ppm$

$NOx_{gas\_mass} \cdot Factor_{ng} = 0.03 \cdot \frac{lb}{MMBTU} \quad NOx_{oil\_mass} \cdot Factor_{no} = 0.1 \cdot \frac{lb}{MMBTU}$

Particulates :
(see note 3)

PM = PM10 =0.005 lb/MMBtu $\quad Particulate = 0.022 \cdot \frac{lb}{MMBTU}$

PM2.5 represents approximately 25% of the total PM

Carbon Monoxide :

$Factor_{Cg} := 0.25 \quad Factor_{Co} := 0.5$

$CO_{gas} \cdot Factor_{Cg} = 20.5 \cdot ppm \quad CO_{oil} \cdot Factor_{Co} = 36.99 \cdot ppm$

$CO_{gas\_mass} \cdot Factor_{Cg} = 0.0151 \cdot \frac{lb}{MMBTU} \quad CO_{oil\_mass} \cdot Factor_{Co} = 0.0300 \cdot \frac{lb}{MMBTU}$

SOx :
(see note 4)

$S = 0.5 \cdot \%$

$SOx_{gas\_corr\_3\%O2\_dry} = 0 \cdot ppm \quad SOx_{oil\_corr\_3\%O2\_dry} = 283 \cdot ppm$

$SOx_{gas\_mass} = 0.000 \cdot \frac{lb}{MMBTU} \quad SOx_{oil\_mass} = 0.51 \cdot \frac{lb}{MMBTU}$

Unburned Hydrocarbons :
Methane & Ethane

$UHC_{gas} = 0.0004 \cdot \frac{lb}{MMBTU} \quad UHC_{oil} = 0.0018 \cdot \frac{lb}{MMBTU}$

VOC :
Propane, Butane ...

$VOC_{gas} = 0.00019 \cdot \frac{lb}{MMBTU} \quad VOC_{oil} = 0.0004 \cdot \frac{lb}{MMBTU}$

NOTES: 1) *ppms are dry volume corrected to 3% O2 volume dry*
2) *Energy units based on fuel HHV*
3) *Particulates are exclusive of any particulates in combustion air or others sources of residual particulates from materials.*
4) *SOx emissions are not burner dependent.*
5) *Not for use in whole or in part for any warranty and/or permit application. the values below are* ***PREDICTED*** *values only and shall be used as such*

1.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

Per K.A.R. 28-19-350, an owner of a facility applying for a PSD air construction permit must perform a BACT analysis for each regulated NSR pollutant for which there would be a significant net emissions increase at the stationary source. This requirement applies to any proposed emissions unit at which a net emissions increase in the air pollutant would occur as a result of a physical change or change in the method of operation in the emissions unit.

The Project is subject to PSD review for CO, NO_x, SO_2, PM/PM_{10}/$PM_{2.5}$, VOC, and CO_2e (greenhouse gases). Therefore, a BACT analysis was performed for each of these pollutants. A summary of the selected control technologies and the associated BACT emission limitations for the rental boiler is presented in Table 1-1.

Table 1-1: Summary of BACT Results

Emissions Unit	Pollutant	Limiting Systems and Controls	BACT Emission Limitation
Rental boiler (EP-20003)	PM	Good combustion practices	0.010 lb/MMBtu
	PM_{10}		
	$PM_{2.5}$		
	NO_x	Low NO_x burners	0.030 lb/MMBtu
	CO	Good combustion practices	0.015 lb/MMBtu
	VOC		0.00019 lb/MMBtu
	SO_2	Low sulfur fuel (natural gas)	0.0006 lb/MMBtu
	GHG	Clean fuels, Good combustion practices, Tune-ups	49,508 tons CO_2e/yr

1.1 BACT for Rental Boiler

The rental boiler is rated at 96.6 MMBtu/hr and will be permitted to operate 8,760 hours per year. The RBLC was examined for similar sized natural gas-fired boilers/heaters (50-99 MMBtu/hr) (See Table D-1, Appendix D in March 2015 application). The RBLC tables also show high variability for emission rates for each pollutant. Only NO_x listed any add-on controls (selective catalytic reduction (SCR) on four units).

1.1.1 BACT for NO_x – Rental Boiler

The rental boiler will combust only natural gas and be permitted for 8,760 hours per year of operation, although actual operation is expected to be less. It will be utilized when steam from the biomass boiler is not available and will not operate at the same time as the Standby Boiler.

1.1.1.1 Step 1. Identify Potential Control Strategies

The only add-on NO_x control technique was SCR for four units listed in the RBLC. Dry low-NO_x burners (LNB) along with combustion controls, are listed as BACT in the RBLC for the rental boiler. There is not a consistent definition of LNB between different vendors, which is evident in the wide range of emissions listed in the RBLC. SCR ranges from 0.009 lb/MMBtu to 0.04 lb/MMBtu; LNB ranges from 0.009 lb/MMBtu to 0.2 lb/MMBtu. These ranges overlap, which supports the conclusion that the definitions are not consistent.

1.1.1.2 Step 2. Identify Technically Feasible Control Technologies

In the second step, the technical feasibility of the control options identified in Step 1 is evaluated with respect to source-specific factors.

1.1.1.2.1 SCR

One SCR vendor indicated it could provide an SCR for the size of the boiler to be used for the Project. The vendor's removal efficiency for this size unit is 90 percent control of NO_x.

As a result, an SCR system is technically feasible for the rental boiler.

1.1.1.2.2 Dry Low-NO_x Burners

LNB are currently available from most rental boiler manufacturers. This technology reduces combustion temperatures, thereby reducing NO_x. In a conventional combustor, the air and fuel are introduced at an approximately stoichiometric ratio, and air/fuel mixing occurs at the flame front where diffusion of fuel and air reaches the combustible limit. A lean premixed combustor design premixes the fuel and air prior to combustion. Premixing produces a homogenous air/fuel mixture, which minimizes localized fuel-rich pockets that produce elevated combustion temperatures and higher NO_x emissions. A lean air-to-fuel ratio approaching the lean flammability limit is maintained, and the excess air serves as a heat sink to lower combustion temperatures, which lowers NO_x formation. A pilot flame is used to maintain combustion stability in this fuel-lean environment.

Dry low-NO_x burners are available on rental boilers and are considered both baseline and technically feasible for the rental boiler.

1.1.1.2.3 Combustion Control

Good combustion practices, also called combustion control, include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure enough oxygen is present for complete combustion.

Good combustion practices is considered baseline for the rental boiler and is technically feasible.

1.1.1.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible NO_x control technologies for the 96.6 MMBtu/hr rental boiler are ranked by control effectiveness in Table 1-2.

Table 1-2: Ranking of NO_x Control Technologies for the Rental Boiler

Control Technology	Reduction (%)	Controlled Emission Level (lb/MMBtu)
SCR	90%	0.057
LNB and Good combustion practices[A]	Not applicable (baseline)	0.030

[A] Based on vendor data

1.1.1.4 Step 4. Evaluate the Most Effective Control Technologies

Each technically feasible control technology was evaluated for energy, environmental, and economic impacts. The results are discussed below for each control technology.

1.1.1.4.1 SCR

<u>Energy and Environmental Impacts</u>. Energy and environmental impacts for an SCR system are discussed in Section 6.3.1.3.

<u>Economic Impacts</u>. The capital costs associated with an SCR system for the rental boiler are shown in Table 1-4. The overall initial capital cost of installing an SCR system on the rental boiler is approximately $380,000. The annualized costs associated with an SCR system are shown in Table 1-5. On an annual basis, the SCR system would cost $269,472, which results in a cost per ton of NO_x removed of $23,588, while removing only 11.4 tons of NO_x per year. Therefore, any control of NO_x by add-on controls would result in costs that would not be economical.

An SCR is not proposed as BACT for the rental boiler because it is not economically feasible.

1.1.1.5 Steps 5. Proposed BACT for NO_x

Since add-on controls are not economically feasible on such a small gas-fired unit, dry low-NO_x burners were selected as BACT for NO_x from the rental boiler at an emission rate of 0.011 lb/MMBtu.

1.1.2 BACT for CO – Rental Boiler

The rental boiler will emit CO during the combustion of natural gas.

1.1.2.1 Step 1. Identify Potential Control Strategies

The RBLC does not list add-on controls in the BACT determinations for control of CO emissions from the rental boiler. Good combustion control will help control emissions of CO from the rental boiler.

1.1.2.2 Step 2. Identify Technically Feasible Control Technologies

Both oxidation catalysts and combustion control must be evaluated in Step 2.

1.1.2.2.1 Oxidation Catalyst System

One control vendor has indicated that a CO catalyst system may be used on a rental boiler this size. The CO catalyst system is an add-on control that converts CO and VOC to carbon dioxide (CO_2) by use of a catalyst. Section 6.3.2.3 in the March 2015 application describes the CO catalyst system for gas-fired units.

An oxidation catalyst system is considered technically feasible for the rental boiler; one vendor has provided a quote for this system.

1.1.2.2.2 Combustion Control

Good combustion practices include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure enough oxygen is present for complete combustion.

Good combustion practices are a technically feasible method of controlling CO emissions from the proposed rental boiler.

1.1.2.3 Step 3. Rank the Technically Feasible Control Technologies

The technically feasible CO control technologies for the rental boiler are ranked by control effectiveness in Table 1-3.

Table 1-3: Ranking of CO Control Technologies for the Rental Boiler

Control Technology	Reduction (%)	Controlled Emission Level (lb/MMBtu)
Oxidation catalyst	80	0.003
Good combustion practices[A]	Not applicable (baseline)	0.015

[A] Based on vendor data

1.1.2.4 Step 4. Evaluate the Most Effective Control Technologies

The oxidation catalyst is the only technology to be evaluated.

Energy and Environmental Impacts. The energy and environmental impacts of an oxidation catalyst are discussed in Section 5.2.4.2.

Economic Impacts. The control cost analysis for an oxidation catalyst system for the rental boiler is displayed in Table 1-6 and Table 1-7. An oxidation catalyst system for this size unit would require an initial capital cost of $50,000. The annual costs of operating this CO catalyst system would be almost $52,467. On an annual basis, only 5.11 tons per year of CO along with 0.04 tons per year of VOC would be removed at a cost of $10,185 per ton of pollutants removed.

The cost is considered economically infeasible; therefore, an oxidation catalyst for control of CO emissions from the rental boiler is not considered BACT.

1.1.2.5 Step 5. Proposed BACT for CO

Since add-on controls are not economically feasible on such a small gas-fired unit, combustion control was selected as BACT for CO from the rental boiler at an emission rate of 0.015 lb/MMBtu.

BACT for CO emissions from the rental boiler is good combustion practices.

1.1.3 BACT for Particulate Matter – Rental Boiler

The rental boiler will emit PM during the combustion of natural gas.

1.1.3.1 Step 1. Identify Potential Control Strategies

The RBLC does not list any control strategies other than good combustion practices and low ash fuel (natural gas). No add-on controls were identified for significant removal of $PM/PM_{10}/PM_{2.5}$ from the rental boiler exhaust.

Table 1-4
SCR System Capital Cost Analysis - Rental Boiler

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$380,000**	A = SCR system cost
Instrumentation	$38,000	0.10 x (A)
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$19,000	0.05 x (A)
Total Purchased Equipment Cost (PEC) [B]	**$437,000**	B = 1.15 x (A)
Direct Installation Costs		
Total Direct Installation Cost	$131,100	0.30 x B
Site Preparation (SP)	$0	As required
Buildings (Bldg.)	$0	As required
Total Direct Cost (DC)	**$568,100**	1.30B + SP + Bldg.
Indirect Costs (Installation)		
Engineering	$43,700	0.10 x B
Construction and field expenses	$21,850	0.05 x B
Contractor fees	$43,700	0.10 x B
Start-up	$8,740	0.02 x B
Performance test	$7,500	Stack Test Vendor Quote
Contingencies	$21,850	0.05 x B
Other	$0	As required
Total Indirect Cost (IC)	**$147,340**	0.32B + Other + Perf. Test
Total Capital Investment (TCI) = DC + IC	**$715,440**	1.62B + Performance test + Other + SP + Bldg.

Table 1-5
SCR System Annual Cost Analysis - Rental Boiler

Item	Value	Basis
Direct Annual Costs (DC)		
Electricity		
Press. Drop (in W.C.)	3.0	Pressure drop - catalyst bed
Power output of Gas Heater (kW)	11,494	ISO Rating
Power Loss Due to Pressure Drop (%)	0.30%	0.1% for every 1" pressure drop
Power Loss Due to Pressure Drop (kW)	34.48	
Unit cost ($/kWh)	$0.045	Estimated market value
Cost of Power Loss ($/yr)	$3,103	Based on operation 2,000 hours/yr
Operating Labor		
Catalyst labor req.	$3,750	1/2 hr/shift @ $30/hr
Ammonia delivery requirement (SCR)	$720	24 hr/yr (3 deliveries per year) @ $30/hr
Ammonia recordkeeping and reporting (SCR)	$1,200	40 hours per year @ $30/hr
Catalyst cleaning	$1,200	40 hours per year @ $30/hr
Supervisor	$563	15% Operating labor
Total Cost ($/yr)	$7,433	
Maintenance		
Catalyst replacement labor	$3,200	107 hr/yr (8 workers, 40 hr, every 3 years)
Catalyst system maintenance labor req.	$3,750	1/2 hr/shift @ $30/hr
Ammonia system maintenance labor req.	$10,950	1 hr/day @ $30/hr
Material	$14,700	100% of maintenance labor
Total Cost ($/yr)	$32,600	
Ammonia		
Requirement (tons/yr)	27.2	29% aqueous ammonia @ $375/ton
Unit Cost ($/ton)	$375	Estimate
Total Cost ($/yr)	$10,187	
Process Air		
Requirement (scf/lb NH_3)	350	
Requirement (mscf/yr)	19,015	
Unit Cost ($/mscf)	$0.20	$0.20 per 1000 scf
Total Cost ($/yr)	$3,803	
Catalyst		
Catalyst Cost ($)	$380,000	Catalyst modules
Catalyst Disposal Cost ($)	$38	Disposal of catalyst modules
Sales Tax ($)	$0	Pollution Control Equipment Exempt
Catalyst Life (yrs)	3	n
Interest Rate (%)	7.0%	i
CRF	0.381	Amortization of catalyst for 3 yrs
Total Cost ($/yr)	$144,814	(Volume) * (Unit Cost) * (CRF)
Indirect Annual Costs (IC)		
Overhead	$0	OAQPS SCR Assumption
Administrative charges	$0	OAQPS SCR Assumption
Annual Contingency	$0	OAQPS SCR Assumption
Property taxes	$0	OAQPS SCR Assumption
Insurance	$0	OAQPS SCR Assumption
Capital Recovery	$67,532	CRF x TCI (20 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$67,532	
Total Annualized Costs (TAC) ($)	**$269,472**	
Total NOx Controlled (ton/yr)	11.4	90% reduction
COST EFFECTIVENESS ($/ton)	**$23,588**	

Table 1-6
CO Catalyst Capital Cost Analysis - Rental Boiler

Item	Value	Basis
Direct Costs		
Purchased Equipment Cost		
Equipment cost + auxiliaries **[A]**	**$50,000**	A
Instrumentation	$5,000	0.10 x (A)
Sales taxes	$0	Pollution Control Equipment Exempt
Freight	$2,500	0.05 x (A)
Total Purchased Equipment Cost (PEC) [B]	**$57,500**	B = 1.15 x (A)
Direct Installation Costs		
Foundations and supports	$4,600.00	0.08 x B
Handling and erection	$8,050	0.14 x B
Electrical	$2,300	0.04 x B
Piping	$1,150	0.02 x B
Insulation for ductwork	$575	0.01 x B
Painting	$575	0.01 x B
Total Direct Installation Cost	$17,250	0.30 x B
Site Preparation (SP)	$0	As required
Buildings (Bldg.)	$0	As required (5-18% PEC)
Total Direct Cost (DC)	**$74,750**	1.3B + SP + Bldg.
Indirect Costs (Installation)		
Engineering	$5,750	0.10 x B
Construction and field expenses	$2,875	0.05 x B
Contractor fees	$5,750	0.10 x B
Start-up	$1,150	0.02 x B
Performance test	$7,500	Stack Test Vendor Quote
Contingencies	$2,875	0.05 x B
Other	$0	As required
Total Indirect Cost (IC)	**$25,900**	0.32B + Other + Perf. Test
Total Capital Investment (TCI) = DC + IC	**$100,650**	1.62B + Performance test + Other + SP + Bldg.

Table 1-7
CO Catalyst Annual Cost Analysis -Rental Boiler

Item	Value	Basis
Direct Annual Costs (DC)		
Steam		
Press. Drop (in W.C.)	3.0	Pressure drop - catalyst bed
Power output of Gas Heater (kW)	11,494	ISO Rating
Output Loss Due to Pressure Drop (%)	0.30%	0.1% for every 1" pressure drop
Output Loss Due to Pressure Drop (kW)	34.48	
Unit cost ($/kWh)	$0.05	Current Purchase Price
Cost of Heat Rate Loss ($/yr)	$3,103	Based on operation 2,000 hours/yr
Operating Labor		Assumed $30/hr
Catalyst labor req.	$3,750	216 hr/yr (1/2 hr/shift. 431 shifts/yr)
Supervisor	$563	15% Operating labor
Total Cost ($/yr)	$4,313	
Maintenance		
Catalyst replacement labor	$3,200	107 hr/yr(8 worker, 40 hr, every 3 years)
Material	$3,200	100% of maintenance labor
Total Cost ($/yr)	$6,400	
Catalyst		
Catalyst Cost ($)	$75,000	Catalyst modules
Catalyst Disposal Cost ($)	$1,500	Disposal of catalyst modules
Sales Tax ($)	$0	Assume exempt from taxes
Catalyst Life (yrs)	3	n
Interest Rate (%)	7%	I
CRF	0.381	Amortization of catalyst over 3 yrs
Total Cost ($/yr)	$29,150	(Volume)(Unit Cost)(CRF)
Indirect Annual Costs (IC)		
Overhead	$0	OAQPS SCR Assumption
Administrative charges	$0	OAQPS SCR Assumption
Annual Contingency	$0	OAQPS SCR Assumption
Property taxes	$0	OAQPS SCR Assumption
Insurance	$0	OAQPS SCR Assumption
Capital Recovery	$9,501	CRF x TCI (20 yr life, 7.0% interest)
Total Indirect Costs ($/yr)	$9,501	
Total Annualized Costs (TAC) ($)	**$52,467**	
Total CO Controlled (ton/yr)	5.11	80% removal
Total VOC Controlled (ton/yr)	0.04	50% removal
COST EFFECTIVENESS ($/ton)	**$10,185**	

1.1.3.2 Step 2. Identify Technically Feasible Control Technologies

The only technically feasible control option is combustion control for $PM/PM_{10}/PM_{2.5}$.

1.1.3.3 Step 3. Rank the Technically Feasible Control Technologies

The only technically feasible control option is combustion control for $PM/PM_{10}/PM_{2.5}$.

1.1.3.4 Steps 4 and 5. Evaluate the Most Effective Control Technologies and Proposed BACT for $PM/PM_{10}/PM_{2.5}$

Since add-on controls are not feasible on such a small gas-fired unit, combustion control was selected as BACT for $PM/PM_{10}/PM_{2.5}$ from the rental boiler at an emission rate of 0.010 lb/MMBtu.

1.1.4 BACT for VOC – Rental Boiler

The rental boiler will emit VOC during the combustion of natural gas.

1.1.4.1 Step 1. Identify Potential Control Strategies

The RBLC does not list add-on controls in the BACT determinations for control of VOC emissions from the rental boiler. As with the turbines, good combustion control will help control emissions of VOC from the rental boiler.

1.1.4.2 Step 2. Identify Technically Feasible Control Technologies

Good combustion practices include operational and design elements to control the amount and distribution of excess air in the flue gas to ensure enough oxygen is present for complete combustion.

Good combustion practices are a technically feasible method of controlling VOC emissions from the proposed rental boiler.

1.1.4.3 Step 3. Rank the Technically Feasible Control Technologies

The only technically feasible control option is combustion control for VOC.

1.1.4.4 Steps 4 and 5. Evaluate the Most Effective Control Technologies and Proposed BACT for VOC

Since add-on controls are not feasible on such a small gas-fired unit, good combustion practices were selected as BACT for VOC from the rental boiler at an emission rate of 0.00019 lb/MMBtu.

1.1.5 BACT for SO_2 – Rental Boiler

The rental boiler will emit SO_2 during the combustion of natural gas.

1.1.5.1 Step 1. Identify Potential Control Strategies

The RBLC does not list any control strategies other than good combustion practices and low sulfur fuel (natural gas). No add-on controls were identified for significant removal of SO_2 from the rental boiler exhaust.

1.1.5.2 Step 2. Identify Technically Feasible Control Technologies

The only technically feasible control option is combustion control for SO_2.

1.1.5.3 Step 3. Rank the Technically Feasible Control Technologies

The only technically feasible control option is combustion control for SO_2.

1.1.5.4 Steps 4 and 5. Evaluate the Most Effective Control Technologies and Proposed BACT for SO_2

Since add-on controls are not feasible on such a small gas-fired unit, combustion control was selected as BACT for SO_2 from the rental boiler at an emission rate of 0.0006 lb/MMBtu.

1.1.6 BACT for GHG – Rental Boiler (Steps 1 – 5)

The rental boiler would be fired exclusively on natural gas, is rated at 96.6 MMBtu/hr, and will be permitted to be fired a total of 8,760 hours per year. GHG emissions from this unit are estimated to be 49,508 tons CO_2e/yr. Abengoa proposes that GHG BACT for this boiler be the following:

- Use clean fuels (exclusive use of natural gas).
- Require Abengoa to maintain the unit according to the manufacturer's specifications and to operate the unit in the most efficient manner possible (i.e., good combustion practices).
- Tune the unit according to the manufacturer's specifications.
- Record the annual hours of operation and annual fuel use, and report the GHG emissions annually. The GHG emissions from this unit may be included in the facility-wide annual GHG limit.