PREVENTION OF SIGNIFICANT DETERIORATION (PSD)

PERMIT SUMMARY

Source ID Number: 1550133

Source Name: Next Generation Processing, LLC. – Haven Gas Plant

Source Location: Section 6, Township 25 South, Range 4 West
Haven, Reno County, Kansas

I. Area Designation

K.A.R. 28-19-350, et seq., Prevention of Significant Deterioration of Air Quality (PSD), affects new major sources and major modifications to major sources in areas designated as "attainment" or "unclassifiable" under section 107 of the Clean Air Act (CAA) for any criteria pollutant. Reno County, Kansas is an attainment/unclassifiable area for all the criteria pollutants.

II. Project Description

Next Generation Processing, LLC. (NGP) is proposing to construct a new natural gas processing facility (Haven Gas Plant) in rural Reno County, approximately two (2) miles from Haven, Kansas. The NGP natural gas processing facility will be located next to the Panhandle Eastern Pipeline Company's Haven transmission facility (Source ID No. 1550008) and will obtain natural gas from the Panhandle Eastern Pipeline Company's Interstate gas pipeline. The design capacity of the natural gas processing facility will be 1.4 billion cubic feet per day (bcfd) and will consist of one (1) amine still rated at 650 gallon per minute to remove Carbon Dioxide (CO_2) and trace amounts of Hydrogen Sulfide (H_2S). The natural gas liquids (NGLs) will then be processed through the cryogenic expander and demethanizer for effective methane and liquid petroleum gases (LPGs) separation. The LPGs will then be compressed and sent to a pipeline. The fraction of natural gas remaining will be compressed and sent back to the Panhandle Eastern Pipeline Company's Interstate gas line. The compression will be accomplished through two (2) Titan 250-30000S natural gas fired combined cycle turbines rated each at 29,299 horse power (hp). Electrical power for the facility will be generated by one (1) Mercury 50-6400R natural gas fired regenerative turbine rated at 6,196 hp and two (2) Waukesha VHP-P9390GSI natural gas fired reciprocating combustion engines rated each at 1,980 hp.

III. Significant Applicable Air Emission Regulations

This proposed source will be subject to Kansas Administrative Regulations relating to air pollution control. The application for this permit was reviewed and will be evaluated for compliance with the following applicable regulations:

A. K.A.R. 28-19-11 Exceptions Due to Breakdown or Scheduled Maintenance – as applied to K.A.R. 28-19-650

B. K.A.R. 28-19-300, Construction Permits and Approvals; Applicability

C. K.A.R. 28-19-350, Prevention of significant deterioration of air quality

D. K.A.R. 28-19-650, Emission Opacity Limitations

E. K.A.R. 28-19-720, Adopting by Reference 40 CFR Part 60, Subpart A, General Provisions.

F. 40 CFR Part 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.

G. 40 CFR Part 60, Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution.[1]

H. 40 CFR Part 63, Subpart A, General Provisions.

I. 40 CFR Part 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

J. K.A.R 28-19-720, Adopting by Reference 40 CFR Part 60, Subpart KKKK, Standards of Performance for Stationary Combustion Turbines.

IV. Air Emissions From the Project

The NGP Haven Gas Plant falls under the 250 ton source category in 40 CFR Part 52.21, therefore the 250 ton threshold is used to determine if a new source is subject to the requirements of 40 CFR Part 52.21.

The potential-to-emit from the new natural gas processing facility is listed in Table 1 of this permit summary and detailed in **Table 1-1** of the initial April 19, 2012 and the final PSD Air Quality Construction Permit Application, Source ID No. 1550133 received on September 13, 2012. Proposed potential-to-emit (PTE) of Oxides of Nitrogen (NO_x), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), Carbon Dioxide equivalents (CO_2e), Particulate Matter (PM), PM less than 10 microns (PM_{10}), PM less than 2.5 microns ($PM_{2.5}$), Ozone (O_3), Hydrogen Sulfide (H_2S), Hazardous Air Pollutants (HAPs) and Volatile Organic Compounds (VOCs) were compared with the Significant Emission Rates for PSD applicability for the criteria and non-criteria pollutants. The proposed Haven Gas Plant is a new major source that has the potential to emit greater than 100,000 tons per year of Greenhouse Gas (GHG) on a CO_2e basis. Therefore the facility is a major source for PSD purposes. In addition PTE of CO, NO_x, and $PM_{2.5}$ are above the PSD

[1] With the promulgation and publication of 40 CFR Part 60, Subpart OOOO, Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution, 40 CFR Part 60, Subparts LLL and KKK are no longer applicable to this proposed project as construction of affected sources will commence after August 23, 2011.

significance levels and will be reviewed under the PSD regulations. Since NO_x emissions for the proposed project are significant, pursuant to 40 CFR Part 52.21, emissions for Ozone (O_3) are also considered significant. Since NO_x is a surrogate for O_3, NO_x emission rates and controls will be representative as emission rates and controls for O_3.

This project will be subject to the various aspects of K.A.R. 28-19-350, such as the use of best available control technology (BACT), ambient air quality analysis, and additional impacts upon soils, vegetation and visibility.

Table 1 - Air Emissions Estimates from the Proposed Activity

Pollutant	Potential to Emit[2] (tons per year)
Oxides of Nitrogen (NO_x)	106.45
Carbon Monoxide (CO)	121.70
Sulfur Dioxide (SO_2)	6.29
Volatile Organic Compounds (VOC)	26.31
Particulate Matter (PM)	14.73
Particulate Matter less than 10 microns (PM_{10})	14.73
Particulate Matter less than 2.5 microns ($PM_{2.5}$)	14.73
Combined Hazardous Air Pollutants (HAPs)	6.31
Individual Hazardous Air Pollutants (HAPs)	
• Acetaldehyde	0.46
• Acrolein	0.37
• Benzene	0.21
• Ethylbenzene	0.06
• Formaldehyde	1.49

[2] Potential-to-emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

Pollutant	Potential to Emit[2] (tons per year)
• Propylene Oxide	0.05
• Toluene	0.24
• Xylenes	0.12
Carbon Dioxide Equivalent (CO_2e)	323,966
• Carbon Dioxide (CO_2)	323,720
• Nitrous Oxide (N_2O)	0.43
• Methane (CH_4)	5.34

V. Best Available Control Technology (BACT)

The BACT requirement applies to new affected emissions units and pollutant emitting activity. Individual BACT determinations are performed for each pollutant emitted from the same emission unit. Consequently, the BACT determination must separately address, for each regulated pollutant with a significant emissions increase at the source, air pollution controls for each emissions unit or pollutant emitting activity subject to review. NGP was required to prepare a BACT analysis for KDHE's review according to the process described in Attachment A of this permit summary. KDHE's evaluation of the BACT for the proposed natural gas processing facility is presented in Attachment B.

Table 2 - NGP Emission Units and Pollutants Subject to BACT

Emission Unit	Pollutants Subject to BACT Review
Solar Titan 250-30000S Natural Gas Turbine (GT-01)	NO_x[3] CO CO_2e $PM_{2.5}$
Solar Titan 250-30000S Natural Gas Turbine (GT-02)	
Solar Mercury 50-6400R Turbine Generator Set (TGS-01)	
Waukesha VHP-P9390GSI Generator Set (EGS-01)	
Waukesha VHP-P9390GSI Generator Set (EGS-02)	
ASV-01 Amine Still Vent Amine Treatment (ASV-01)	CO_2e
Fugitive Emissions	CO_2e (CH_4)

[3] NOx emissions for the project exceed the 40 tons significance threshold, therefore pursuant to 40 CFR 52.21, the project is also significant for O_3. Since NO_x is a surrogate for O_3, BACT for NOx will be considered BACT for O_3.

KDHE has concurred with NGP for the following BACT controls and operational conditions:

A. Solar Turbines, Inc. Model Titan 250-30000S Natural Gas Compressor Turbines (GT-01 and GT-02):

1. BACT for NO_x is 15 ppmv @ 15 % O_2 or 11.31 lb/hr on a 1-hour average from each Titan 250-30000S Natural Gas Turbine, excluding periods of startup, shutdown, and malfunction. The NO_X emissions from each Titan 250-30000S Natural Gas Turbine shall be controlled with the manufacturer supplied $SoLoNO_x$ dry low NO_x/lean pre-mixed combustion technology and with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the turbines. The owner or operator must operate and maintain the $SoLoNO_x$ dry low NO_x/lean pre-mixed combustion technology per recommendations of the manufacturer to assure proper and effective operation. The owner will be required to perform initial performance testing. The owner or operator shall be required to install a Continuous Emission Monitoring System (CEMS) to demonstrate continuous compliance with the BACT NO_x limit.

2. In addition, BACT for NO_x is 15 ppmv @ 15 % O_2 or 11.31 lb/hr on a 30 day rolling average from each Titan 250-30000S Natural Gas Turbine, including periods of startup, shutdown, and malfunction.

3. BACT for CO is 25 ppmv @ 15 % O_2 or 11.49 lb/hr from each Titan 250-30000S Natural Gas Turbine, including periods of startup, shutdown, and malfunction. The CO emissions from each Titan 250-30000S Natural Gas Turbine shall be controlled with the manufacturer supplied $SoLoNO_x$ dry low NO_x/lean pre-mixed combustion technology and with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the turbines. The owner or operator must operate and maintain the $SoLoNO_x$ dry low NO_x/lean pre-mixed combustion technology per recommendations of the manufacturer to assure proper and effective operation. The owner will be required to perform initial performance testing. Continuous compliance will be demonstrated with subsequent performance testing at the same time as Relative Accuracy Test Audits (RATAs) for the NO_x CEMs.

4. BACT for $PM_{2.5}$ is 1.24 lb/hr, both filterable and condensable $PM_{2.5}$, including periods of startup, shutdown, and malfunction from each Titan 250-30000S Natural Gas Turbine. The $PM_{2.5}$ emissions from each Titan 250-30000S Natural Gas Turbine shall be controlled with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the turbines. The owner will be required to perform initial performance testing. If initial performance testing results indicate emission rates are less than 90% of the emission limitation, the frequency of subsequent performance testing shall be every 5 years. However, if the initial or any subsequent performance test conducted fails to demonstrate emission rates less than 90% of the emission limitation, then a more frequent testing schedule shall be required. If

performance testing results indicate emission rates are greater than 90% of the emission limitation, subsequent testing shall be performed at the same frequency as and in conjunction with the RATA testing of the NO_x continuous emissions monitor or until a subsequent performance test result indicates the emission rate is less than 90% of the emission limitation, at which time the frequency of testing can be reduced to every five years.

5. BACT for CO_2e is 134, 724 lbs of CO_2e/MMScf of Natural Gas Fired. The CO_2e emissions from each Titan 250-30000S Natural Gas Turbine shall be controlled with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the turbines. The owner will be required to perform initial performance testing. The owner or operator will be required to track fuel fired in the turbines and calculate the monthly and twelve month rolling average of actual lbs of CO_2e/MMScf per unit to compare with the limit. Additionally, waste heat from the turbines will be utilized to heat a hot oil system used by the Demethanizer unit, the Mol Sieve Dehydrator unit and the Amine Unit, in place of regenerative boilers for those systems.

B. Solar Turbines, Inc. Model Mercury 50-6400R Natural Gas Generator Set (TGS-01):

1. BACT for NO_x is 5 ppmv @ 15 % O_2 or 0.81 lb/hr on a 24-hour average, including periods of startup, shutdown, and malfunction. The NO_X emissions from the Mercury 50-6400R Natural Gas Turbine shall be controlled with the manufacturer supplied ultra-lean-premix (ULP) dry low NOx combustion technology and with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the turbine. The owner or operator must operate and maintain the ultra-lean-premix (ULP) dry low NOx combustion technology per recommendations of the manufacturer to assure proper and effective operation. The owner will be required to perform initial performance testing. The owner or operator shall be required to install CEMS or a continuous parameter monitoring system to demonstrate continuous compliance with the BACT NO_x limit.

2. BACT for CO is 10 ppmv @ 15 % O_2 or 0.97 lb/hr including periods of startup, shutdown, and malfunction. The CO emissions from the Mercury 50-6400R Natural Gas Turbine shall be controlled with the manufacturer supplied ultra-lean-premix (ULP) dry low NOx combustion technology and with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the turbine. The owner or operator must operate and maintain the ultra-lean-premix (ULP) dry low NOx combustion technology per recommendations of the manufacturer to assure proper and effective operation. The owner will be required to perform initial performance testing. If the initial performance test results indicate emission rates are less than 90% of the emission limitation, the frequency of subsequent performance testing shall be every 5 years. However if the initial or any subsequent performance test conducted fails to demonstrate emission rates less than 90% of the emission limitation, then a more frequent testing schedule shall be required. If performance testing results indicate emission rates are greater than 90% of the

emission limitation, subsequent testing shall be conducted at least once every four (4) calendar quarters to validate the accuracy of parameter monitoring equipment or until a subsequent performance test result indicates the emission rate is less than 90% of the emission limitation, at which time the frequency of testing can be reduced to every five years.

3. BACT for $PM_{2.5}$ is 0.27 lb/hr, both filterable and condensable $PM_{2.5}$, including periods of startup, shutdown, and malfunction from the Mercury 50-6400R Natural Gas Turbine. The $PM_{2.5}$ emissions from the Mercury 50-6400R Natural Gas Turbine shall be controlled with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the turbines. The owner will be required to perform initial performance testing. If initial performance testing results indicate emission rates are less than 90% of the emission limitation, the frequency of subsequent performance testing shall be every 5 years. However if the initial or any subsequent performance test conducted fails to demonstrate emission rates less than 90% of the emission limitation, then a more frequent testing schedule shall be required. If performance testing results indicate emission rates are greater than 90% of the emission limitation, subsequent testing shall be performed at least once every four (4) calendar quarters or until a performance test result indicates the emission rate is less than 90% of the emission limitation, at which time the frequency of testing can be reduced to every five years.

4. BACT for CO_2e is 120, 279 lbs of CO_2e/ MMScf of Natural Gas Fired. The CO_2e emissions from the Mercury 50-6400R Natural Gas Turbine shall be controlled with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the turbines. The owner will be required to perform initial performance testing. The owner or operator will be required to track fuel fired in the turbine and calculate the monthly and twelve month rolling average of actual lbs of CO_2e/MMScf per unit to compare with the limit. Additionally, this facility is planning to obtain at least 35% of its electrical power needs from the utility grid.

C. Waukesha Model VHP-P9390GSI Natural Gas Reciprocating Engine Generator Sets (EGS-01 and EGS-02):

1. BACT for NO_x is 0.10 g/bhp-hr, including periods of startup, shutdown, and malfunction. The NO_X emissions from each Waukesha Natural Gas Reciprocating Engine Generator Set shall be controlled with dual non-selective catalytic reduction and with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the engines. The owner or operator must operate and maintain dual non-selective catalytic reduction combustion technology per recommendations of the manufacturer to assure proper and effective operation. The owner will be required to perform initial performance testing. Continuous compliance shall be demonstrated on

an ongoing basis by conducting a performance test annually thereafter. Portable analyzer testing according to ASTM Method D6522-00 or other methods included in Table 2 to Subpart JJJJ of Part 60 may be used for subsequent testing.

2. BACT for CO is 0.30 g/bhp-hr, including periods of startup, shutdown, and malfunction. The CO emissions from each Waukesha Natural Gas Reciprocating Engine Generator Set shall be controlled with dual non-selective catalytic reduction and with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the engines. The owner or operator must operate and maintain dual non-selective catalytic reduction combustion technology per recommendations of the manufacturer to assure proper and effective operation. The owner will be required to perform initial performance testing. Continuous compliance shall be demonstrated on an ongoing basis by conducting a performance test annually thereafter. Portable analyzer testing according to ASTM Method D6522-00 or other methods included in Table 2 to Subpart JJJJ of Part 60 may be used for subsequent testing.

3. BACT for $PM_{2.5}$ is 0.30 lb/hr including periods of startup, shutdown, and malfunction. The $PM_{2.5}$ emissions from each Waukesha Natural Gas Reciprocating Engine Generator Set shall be controlled with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the turbines. The owner will be required to perform initial performance testing. If the initial performance test results indicate emission rates are less than 95% of the emission limitation, the frequency of subsequent performance testing shall be every 5 years. However, if any initial or any subsequent performance test conducted fails to demonstrate emission rates less than 95% of the emission limitation, then a more frequent testing schedule shall be required. If performance test results indicate emission rates are greater than 95% of the emission limitation, subsequent testing shall be conducted at least once every four (4) calendar quarters or until a subsequent performance test result indicates the emission rate is less 95% of the emission limitation, at which time the frequency of testing can be reduced to every five years.

4. BACT for CO_2e is 116, 590 lbs of CO_2e/ MMScf of Natural Gas Fired. The CO_2e emissions from the Waukesha Model VHP-P9390GSI Natural Gas Reciprocating Engine Generator Sets shall be controlled with good combustion practices. The owner or operator will be limited to firing pipeline quality natural gas only in the turbines The owner will be required to perform initial performance testing. The owner or operator will be required to track fuel fired in the turbine and calculate the monthly and twelve month rolling average of actual lbs of CO_2e/MMScf per unit to compare with the limit. Additionally, this facility plans to obtain at least 35% of its electrical power needs from the utility grid.

D. Amine Unit (ASV-01)

BACT for CO_2e is 6.02 lbs of CO_2e per barrel of Natural Gas Liquids (NGL) processed, regeneration of amine will be conducted by hot oil heated by the waste heat from the two (2) Titan 250-30000S, instead of installing an additional fired amine reboiler.

E. Fugitive emissions (FUG-01)

BACT for CO_2e is natural gas feed stock only and an effective Leak Detection and Repair (LDAR) Program. The owner or operator shall conduct the program as described in 40 CFR Part 60 Subpart OOOO which references requirements of 40 CFR Part 60 Subpart VVa.

1. Reciprocating Compressors (C-3 and C-5):

   Prior to the publication of 40 CFR Part 60 Subpart OOOO, these reciprocating compression units would have been covered under LDAR requirements or 40 CFR Part 60 Subpart VV that would have been referenced in 40 CFR Part 60 Subpart KKK. However, 40 CFR Part 60 Subpart OOOO which will be applicable to these units has separate requirements for these units that are not referenced to Subpart VVa or other LDAR-type monitoring requirements. Therefore BACT for CO_2e is natural gas feed stock only and compliance with the requirements of 40 CFR Part 60 Subpart OOOO.

2. Centrifugal Compressors (C-1, C-2a, C-2b, and C-4):

   Prior to the publication of 40 CFR Part 60 Subpart OOOO, these centrifugal compression units would have been covered under LDAR requirements or 40 CFR Part 60 Subpart VV that would have been referenced in 40 CFR Part 60 Subpart KKK. However, 40 CFR Part 60 Subpart OOOO will not be applicable to these units, as they will be equipped with dry seals. To comply with BACT requirements, these units shall be included in the facility's LDAR program. Under the authority of K.A.R. 28-19-302(a), the facility shall comply with the applicable sections of 40 CFR Part 60 Subpart VVa.

VI. Ambient Air Impact Analysis

A. Impact Analysis

The owner or operator of a proposed source or modification must demonstrate that allowable emission increases from the proposed source, in conjunction with all other applicable emissions increases or reductions would not cause or contribute to air pollution in violation of:

- any national ambient air quality standard (NAAQS) in any air quality control region; or
- any applicable maximum allowable increase over the baseline concentration in any area.

The AERMOD model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads.

Pollutant emission rates (lb/hour) used in AERMOD are listed in the permit application received April 19, 2012, **Section 11.0**. Stack parameters are listed in the permit application Appendix A. Alternate operating scenarios, associated emission rates, and stack parameters are listed in the Memorandum submitted May 14, 2012, Re: Results for Alternate Modeling Scenarios for the Haven Gas Plant. Five (5) years of meteorological data from 2006-2010, of surface and upper air were used in the modeling analysis. The upper air data was from the Dodge City Regional Airport (KDDC) meteorological station, WBAN# 13985 and the surface air data was from the Hutchinson Municipal Airport (KHUT) meteorological station, WBAN #13986.

Various operating scenarios were modeled to determine worst case dispersion condition and highest model predicted concentrations. Emissions from the proposed facility were modeled by the facility's consultant using three (3) different emission scenarios.

- Scenario 1 assumes all units are operating at 100% load.

- Scenario 2 assumes the two (2) GT-01 and GT-02 gas turbines are operating at 75% load, the TGS-01 turbine generator set is operating at 100% load, the EGS-01 engine generator set is operating at 100% load, and the EGS-02 engine generator set is not operating. KDHE runs were the same for Scenario 2, except that EGS-02 engine generator set was operating at 100% load.

- Scenario 3 assumes the GT-01 gas turbine is operating at 100% load, the GT-02 gas turbine is not operating, the TGS-01 turbine generator set is operating at 100% load, and the EGS-01 and EGS-02 engine generator sets are not operating.

The facility originally requested approval to model 1-hour NO_2 using the OLM Tier 3 method, which requires approval from EPA Region 7. The facility then submitted Tier 1 modeling results on May 29 (Scenario 1) and May 31 (Scenario 2). The Tier 1 analysis does not require approval from EPA Region 7. Results indicated that worst case predicted emissions impacts were less than the Significant Impact Level (SIL, both KDHE SIL of 10 ug/m^3 and EPA SIL of 7.5 ug/m^3). For a summary of results, refer to emails submitted on May 29, 30, and 31.

Results for all pollutants except 1-hour NO_2 are in the permit application (submitted April 19, 2012) **Table 14-2, page 88** (also in the updated permit application submitted September 13, 2012, **Table 14-2, page 124**). Worst case modeled impacts were less than the applicable SIL for each pollutant and averaging period.

Since the facility modeling indicated that modeled impacts are less than the applicable SIL for all pollutants, no additional analysis is needed to demonstrate compliance with the NAAQS and PSD Class II increment (the whole state of Kansas is designated as a Class II area).

Since refined modeling was not required, preliminary modeling results were used to determine the project's increment consumption. The highest first high concentration was used for comparison with each pollutant and averaging period. The results are summarized below in **Table 3**:

Table 3. Proposed NGP Facility Increment Consumption

Pollutant	Averaging Period	Modeled Concentration (µg/m^3)	Class II Increment (µg/m^3)	% of Increment
NO_2	Annual (H1H)	0.33	25	1.3
$PM_{2.5}$	Annual (H1H)	0.08	4	2.0
	24-hour (H1H)	0.58	9	6.4

EPA has not established a 1-hour Class II maximum allowable increment for NO_2 or CO. Therefore, no calculation of the potential consumption of such increment is possible.

B. Additional Impact Analysis

In accordance with 40 CFR 52.21(o)(1), the owner shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of this project and to what extent the emissions from the proposed modification impacts the general commercial, residential, industrial and other growth.

C. Visibility Impairment Analysis

The facility conducted a visibility degradation analysis for the NO_x and particulate matter emissions from the proposed modification. The facility used the document "Workbook for Plume Visual Impact Screening and Analysis", EPA 450/4-88-015, September 1988, and the EPA approved dispersion modeling procedure "VISCREEN" for guidance. A visibility analysis was performed for the nearest Class I (visibility-sensitive) area, Hercules Glades Wilderness Area. The results indicate that there are no exceedances of the screening criteria. The results summary and output data are included in Appendix B of the permit application.

In accordance with EPA and KDHE guidance, a visibility impairment analysis was also conducted at Haven High School in Haven, approximately three miles from the proposed Haven Gas Plant. The composite worst case hourly emission rate over all modes of operation for NO_x and PM from the modifications were input into the model, along with the most conservative meteorological conditions. The Level 2 VISCREEN results indicate that there are no exceedances of the screening criteria. Results were submitted in an email dated June 26, 2012, and also in the updated permit application submitted September 13, 2012, Appendix B.

D. Impacts on Vegetation

The permit application included an analysis which determined that the proposed facility and the associated increases of NO_2, SO_2, CO, PM_{10}, $PM_{2.5}$, and VOC /ozone are not expected to have significant effects on vegetation.

Air pollutants can affect vegetation through direct absorption through the foliage, or uptake from the soil of trace elements deposited in the soil. The effects of air pollution on vegetation can include visible damage to foliage and fruit, changes in metabolic function, adverse changes in plant activity, and crop yield reduction. The effects of air pollutants on vegetation fall into three categories: acute (short exposure to high concentration), chronic (lower concentration over months or years), and long term (abnormal changes to ecosystems and physiological alterations in organisms that occur gradually over very long time periods).

The KDHE review included referring to EPA's Screening Procedure for Impacts of Air Pollution Sources on Plants, Soils, and Animals. Table 3.1 of the screening guidance lists screening concentrations for exposure to ambient air concentrations. For NO_2, the shortest averaging period listed was 4 hours with a minimum reported level of 2.0 ppmv for sensitive vegetation. As stated in the facility's review, the proposed project is not expected to exceed the NAAQS (0.100 ppm for 1-hour NO_2). This is lower that the

screening concentration listed in EPA's Screening Procedure for Impacts of Air Pollution Sources on Plants, Soils, and Animals. Available predicted impacts are below levels at which any adverse impact on vegetation is expected.

E. Impacts on Soils

The permit application included an analysis which determined that the proposed facility and the associated increases of NO_2, SO_2, CO, PM_{10}, $PM_{2.5}$, and VOC /ozone are not expected to have significant effects on soil.

The KDHE review included referring to EPA's Screening Procedure for Impacts of Air Pollution Sources on Plants, Soils, and Animals. As stated in the facility's review, the proposed project is not expected to exceed the NAAQS (0.100 ppm for 1-hour NO_2). This is lower that the screening concentration listed in EPA's Screening Procedure for Impacts of Air Pollution Sources on Plants, Soils, and Animals. Available predicted impacts are below levels at which any adverse impact on soil is expected.

F. Growth in Commercial, Residential and Industrial activity

Per the permit application, the construction of this facility will result in numerous temporary construction jobs. Industrial growth is not expected to increase significantly due to construction of the facility. The operation of the facility will require approximately 10 employees, some of which are anticipated to be hired from the local area. Therefore, residential growth is not anticipated to add appreciably to air emissions in the vicinity of the facility. Similarly, associated growth in commercial business and industrial support will be minimal.

Key Steps in the 'Top-Down' BACT Analysis

The four steps in the 'Top-Down' BACT Analysis are presented in Attachment A.

VII. BACT Analysis for PSD Permit

KDHE's evaluation of the BACT for the proposed NGP facility is presented in Attachment B

Attachment A

KEY STEPS IN THE "TOP-DOWN" BACT ANALYSIS

STEP 1: **IDENTIFY ALL POTENTIAL AVAILABLE CONTROL TECHNOLOGIES.**

The first step in a "Top-Down" analysis is to identify, for the emission unit in question, "all available" control options. Available control options are those air pollution control technologies or techniques with a PRACTICAL POTENTIAL FOR APPLICATION to the emissions unit and the regulated pollutant under review. This includes technologies employed outside of the United States. Air pollution control technologies and techniques include the application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

STEP 2: **ELIMINATE TECHNICALLY INFEASIBLE OPTIONS.**

The technical feasibility of the control options identified in Step 1 is evaluated with respect to the source-specific (or emissions unit specific) factors. In general, a demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

STEP 3: **RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS.**

All remaining control alternatives not eliminated in Step 2 are ranked and then listed in order of over-all control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit subject to a BACT analysis.

The list should present the array of control technology alternatives and should include the following types of information:

1) control efficiencies;

2) expected emission rate;

3) expected emission reduction;

4) environmental impacts;

5) energy impacts; and

6) economic impacts.

STEP 4: **EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS.**

The applicant presents the analysis of the associated impacts of the control option in the listing. For each option, the applicant is responsible for presenting an objective evaluation of each impact. Both beneficial and adverse impacts should be discussed and, where possible, quantified. In general, the BACT analysis should focus on the direct impact of the control alternative. The applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. In the event the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be fully documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology cannot be eliminated.

STEP 5: **SELECT BACT.**

The most effective control option not eliminated in Step 4 is proposed as BACT for the emission unit to control the pollutant under review.

Attachment B

KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT'S EVALUATION

OF NEXT GENERATION PROCESSING, LLC (NGP) – HAVEN GAS PLANT

I. PROPOSED BACT OPTIONS

Next Generation Processing, LLC. (NGP) conducted a BACT analysis to determine the appropriate control of emissions from the proposed Haven Gas Plant. This facility will consist of the following emissions sources: two(2) Solar Turbines, Inc. Model Titan 250-30000S Natural Gas Compressor Turbines (GT-01 and GT-02), one (1) Solar Turbines, Inc Model Mercury 50-6400 Natural Gas Turbine Generator Set (TGS-01); two (2) Waukesha Model VHP-P9390GSI natural gas fired reciprocating engine generator sets (EGS-01 and EGS-02); one (1) Mol Sieve Desiccant Dehydration System; one (1) Still Vent Amine Treatment (ASV-01); one (1) vertical fixed roof tank (TK-01) storing a hydrocarbon liquid (slop oil); truck loadout operations for TK-01 (TRKLD); one (1) 3,500 hp electric inlet compressor (C-1); one (1) 200 hp electric regenerative compressor (C-4); one (1) 50 hp electric drive amine flash tank compressor (C-5); process piping fugitives which include valves, flanges, connections, piping and pressure relief valves accounted as fugitive emissions (FUG-1).

The units subject to BACT review are as described in ***Table 2 - NGP Emission Units and Pollutants Subject to BACT*** in Section V of the Permit Summary.

The proposed operating scenario for each Solar Turbines, Inc. Model Titan 250-30000S unit includes operating at 100% load capacity with no limitation for annual operation. NGP anticipates that these turbines will only be taken offline for planned maintenance startup and shutdown (MSS) events. Manufacturing estimates provided by NGP indicate that each shutdown event for the Titan-250-30000S turbine requires 10 minutes and each startup event requires 10 minutes. NGP further anticipates that no more than six (6) planned MSS events per turbine will be required annually. The units will be fired on natural gas only. These emission units are combined-cycle turbines that will be used to compress natural gas and will incorporate circular waste heat recovery which will be used to heat thermal oil that for regenerative systems in the Amine and Mol Sieve Dehydrator units.

The proposed operating scenario for the Solar Turbines, Inc Model Mercury 50-6400 includes operating at 100% load capacity with no limitation for annual operation. NGP anticipates that this unit will only be taken offline once per year for planned MSS events. Manufacturing estimates provided by NGP indicate that a shutdown event takes approximately 9 minutes and the startup event takes approximately 20 minutes. The unit will be fired on natural gas only. The unit is a simple-cycle gas turbine equipped with a recuperator, which is used to preheat the combustion air. This unit will be used for electrical power generation at the Haven Gas Plant.

The proposed operating scenario for each Waukesha Model VHP-P9390GSI unit includes operating at 100% load capacity with no limitation for annual operation and running concurrently with the Solar Turbines, Inc Model Mercury 50-6400 for power generation at the Haven Gas Plant. NGP anticipates that these units will not be taken offline for planned MSS events.

The proposed operating scenario for the Still Vent Amine Treatment is 100% capacity. The amine treatment operations will process the natural gas liquid product following cryogenic expansion in order to remove approximately 95% of the CO_2. The proposed operating scenario for the amine unit corresponds with plant wide operational scenarios and will correspond with MSS events of the Solar Turbines, Inc. Model Titan 250-30000S.

The Process Fugitives from the project are emission from leaking components, such as valves, flanges, electric compressors, pressure relief devices and connectors. The proposed operating scenario for this equipment corresponds with plant wide operational scenarios and will correspond with MSS events of the Solar Turbines, Inc. Model Titan 250-30000S.

The following represents the KDHE's proposals for BACT supported by a summary of the analysis done for each control option. Please refer to the BACT analysis in **Section 12.0** of the PSD application for a more thorough evaluation of possible BACT.

II. BACT Analysis for NO_x, CO and $PM_{2.5}$

A. Titan 250-30000S Natural Gas Compressor Turbines

1. NO_x BACT

Nitrogen oxide control methods are divided into two categories: add-on control and in-combustor NO_x formation control. The different types of emission controls reviewed by NGP are as follows:

Add-on Controls:

- EMxGT (formerly $SCONO_x^{TM}$)
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

In Combustor type:

- Water and Steam Injection
- Rich/Quench/Lean (RQL)
- Alternate Lower Fuel Bound Nitrogen (FBN) Fuels
- XONON
- Dry Low NO_x (DLN) (SoLoNOx)

a. EMxGT (formerly $SCONO_x^{TM}$) is a catalytic oxidation/absorption technology that has been applied for reductions of NOx, CO, and VOC from an assortment of combustion applications that mostly include small turbines, boilers, and lean-burn engines. The operating temperature range for $SCONO_x$ is 300°F to 700°F, is not readily adaptable to high-temperatures and is susceptible to potential thermal cycling. Exhaust temperatures for the Titan 250 prior to waste heat recover, at 100% load, will be approximately 863° Fahrenheit (F), and after waste heat recover will be approximately 701° F. Information contained on the RACT/BACT/LAER Clearinghouse does not demonstrate that this technology has been placed on a commercial combined- or simple cycle turbines comparable to the units proposed by NGP. Therefore, $SCONO_x$ is eliminated from further consideration as BACT for the Titan 250-30000S Natural Gas Compressor Turbines.

b. SCR is generally considered the top level of control that is commercially available for combustion turbines—especially combined cycle units. SCR uses a reaction with ammonia in the presence of a catalyst to form N_2 and H_2O. NO_x removal of up to 70-90 percent is achievable and the greatest NO_x reduction occurs at catalyst bed temperatures between 400° F and 800°F, for base metal catalyst types (i.e., vanadium-titanium catalysts temperature range 550F-800F). This makes the SCR technically feasible for use individually on each turbine. The total capital and annual costs associated with an SCR system for each of the Titan 250-30000S turbines was provided in **Table 12-5** and **Appendix D** of the permit application. The tables within **Appendix D** present the incremental cost effectiveness of applying an SCR to each respective turbine. The SCR costs associated with each turbine model exceed the amount that would be considered cost effective for a combined cycle combustion turbine in this area. Thus, SCR is eliminated from consideration as BACT for the Titan 250-30000S turbines.

An analysis of the technical and economical feasibility of both Titan 250-30000S turbines venting to a single SCR system was also performed. The manufacturer of the SCR would not warrantee an emission rate for a single SCR to the 2.5 PPM emission rate which is technically feasible for single SCR systems on each turbine, therefore the a combined SCR system is eliminated from consideration as BACT for the Titan 250-30000S turbines.

c. SNCR uses urea or ammonia injection, similar to SCR, but it operates at a higher temperature range (1,700°F to 2,000°F). However, this required temperature range is much higher than the exhaust temperatures of the Titan 250-30000S turbines. Therefore, SNCR is considered to be technically infeasible for the proposed combustion turbines.

d. Water and steam injection reduces flame temperature, and subsequently lowers NO_x, by injecting water or steam into the combustion chamber. This technology has been widely used since the 1970's however, the proposed turbines for this project come equipped with $SoLoNO_x$ dry low No_x technology and a review of the RBLC did not reveal water or steam injection in combination with dry low NOx technology as a method of NOx reduction. In addition, water injection is not commercially available with the Titan 250-30000S turbines. For this reason, water or steam injection is considered technically infeasible for controlling NO_x emissions from the Titan 250-30000S turbines when equipped with $SoLoNO_x$ dry low NO_x technology.

e. Rich/Quench/Lean (RQL) is a combustor technology with a fuel-rich primary zone and fuel lean secondary zone. It promises to achieve significant NO_x emission reduction but remains in the development phase for most turbine designs and not commercially available for all turbine manufacturers. For this reason, RQL is considered technically infeasible for controlling NO_x emissions from the Titan 250-30000S turbines.

f. Alternate Lower Fuel Bound Nitrogen (FBN) Fuels such as coal-derived gas or methanol is not practical based on the nature of the Haven Gas Plant project and is therefore deemed technically infeasible for use in the Titan 250-30000S turbines.

g. XONON utilizes flameless catalytic combustion to limit NO_x formation by reducing the combustion temperature. This technology has been proven to be effective on small turbines (<10 MW), but has never been successfully applied to larger combustion turbines. Additionally the XONON technology is an emerging technology not commercially available for all turbine manufacturers and still in scale up phase. For this reason, XONON is considered technically infeasible for controlling NO_x emissions from large combustion turbines, such as the Titan 250-30000S turbines.

h. Dry low NO_x (DLN) burners reduce flame temperature, thus reducing NO_x emissions, by use of two-stage combustor technology. This technology is commercially available on the Titan 250-30000S turbines. The Titan 250-30000S turbines units will be supplied with $SoLoNO_x$ dry low No_x technology, which are capable of achieving long-term NO_x emissions of 15 parts per million dry volume (ppmdv) at 15 percent oxygen while firing natural gas. Therefore, DLN is BACT for NO_x for the Titan 250-30000S turbines.

2. CO BACT

Two types of carbon monoxide control techniques have been identified as applicable to the Titan 250-30000S turbines:

- Catalytic Oxidation
- Combustion Control.

a. The highest level of CO control is catalytic oxidation. A catalytic oxidation system utilizes a passive reactor system that consists of a grid coated with a catalyst. Exhaust from the turbine passes over the catalyst and the CO is oxidized to CO_2. Catalytic oxidation has been technically proven as an effective control alternative for simple cycle combustion turbines. The total capital and annual costs associated with Catalytic oxidation for each of the Titan 250-30000S turbines was provided in **Table 12-7** and **Appendix D** of the permit application. The incremental cost effectiveness associated with catalytic oxidation for CO control is $6,500 per ton for each Titan 250-30000S turbine. As a result, catalytic oxidation is rejected as BACT for CO control on each Titan 250-30000S turbine.

b. While utilizing good combustion practices, each Titan 250-30000S turbine can achieve sustained CO emission levels at 25 ppmdv corrected to 15 percent O_2. The lean combustion dry low NO_x control technology ($SoLoNO_x$) proposed for reducing NO_x emissions also compensates for CO emissions. Given that this is a CO attainment/unclassifiable area and the fact that the predicted maximum impact of CO emissions on the surrounding environment will not be significant, good combustion practices is proposed as BACT for CO emissions from the Titan 250-30000S turbines.

3. $PM_{2.5}$ BACT

Inherently low emissions of $PM_{2.5}$ result from natural gas combustion due to high combustion efficiencies and the clean-burning nature of natural gas. EPA's RBLC database of natural gas fired combustion turbines does not indicate controls for $PM_{2.5}$ beyond good combustion practices. Therefore, good combustion practice is BACT for $PM_{2.5}$ for the Titan 250-30000S turbines.

B. Mercury 50-6400R Natural Gas Turbine Generator Set

1. NO_x BACT

Nitrogen oxide control methods are divided into two categories: add-on control and in-combustor NO_x formation control. The different types of emission controls reviewed by NGP are as follows:

Add-on Controls:

- EMxGT (formerly $SCONO_x^{TM}$)
- Selective Catalytic Reduction (SCR)
- Selective Non-Catalytic Reduction (SNCR)

In Combustor type:

- Water and Steam Injection
- Rich/Quench/Lean (RQL)
- Alternate Lower Fuel Bound Nitrogen (FBN) Fuels
- XONON
- Dry Low NO_x (DLN) (SoLoNOx)

a. EMxGT (formerly $SCONO_x^{TM}$) is a catalytic oxidation/absorption technology that has been applied for reductions of NOx, CO, and VOC from an assortment of combustion applications that mostly include small turbines, boilers, and lean-burn engines. The operating temperature range for SCONO is 300°F to 700°F, is not readily adaptable to high-temperatures and is susceptible to potential thermal cycling. Exhaust temperatures for the Mercury 50-6400R at 100% load will be approximately 685° Fahrenheit (F) (Engine inlet temperature of 40° F and 60% humidity), and could range as high as approximately 738° F (engine inlet temperature of 100 ° F at 60% humidity). Information contained on the RACT/BACT/LAER Clearinghouse does not demonstrate that this technology has been placed on a commercial combined- or simple cycle turbines comparable to the units proposed by NGP. Therefore, $SCONO_x$ is eliminated from further consideration as BACT for the Mercury 50-6400R Turbine.

b. SCR is generally considered the top level of control that is commercially available for combustion turbines—especially combined cycle units. SCR uses a reaction with ammonia in the presence of a catalyst to form N_2 and H_2O. NO_x removal of up to 70-90 percent is achievable and the greatest NO_x reduction occurs at catalyst bed temperatures between 400° F and 800°F, for base metal catalyst types (i.e., vanadium-titanium catalysts temperature range 550F-800F). This makes the SCR technically feasible for use. The total capital and annual costs associated with an SCR system for the Mercury 50-6400R turbine was provided in **Table 12-5** and **Appendix D** of the permit application. The tables within **Appendix D** present the incremental cost effectiveness of applying an SCR to the turbine. The SCR costs associated with this turbine model exceed the amount that would be considered cost effective for a combined cycle combustion turbine in this area. Thus, SCR is eliminated from consideration as BACT for the Mercury 50-6400R turbine.

c. SNCR uses urea or ammonia injection, similar to SCR, but it operates at a higher temperature range (1,700°F to 2,000°F). However, this required temperature range is much higher than the exhaust temperatures of the Mercury 50-6400R turbine. Therefore, SNCR is considered to be technically infeasible for the proposed combustion turbine.

d. Water and steam injection reduces flame temperature, and subsequently lowers NO_x, by injecting water or steam into the combustion chamber. This technology has been widely used since the 1970's however, the proposed turbine for this project comes equipped with ultra-lean-premix (ULP) dry low NOx technology and a review of the RBLC did not reveal water or steam injection in combination with dry low NOx technology as a method of NOx reduction. In addition, water injection is not commercially available with the Mercury 50-6400R turbine. For this reason, water or steam injection is considered technically infeasible for controlling NO_x emissions from the Mercury 50-6400R turbine when equipped with ultra-lean-premix (ULP) dry low NOx technology.

e. Rich/Quench/Lean (RQL) is a combustor technology with a fuel-rich primary zone and fuel lean secondary zone. It promises to achieve significant NO_x emission reduction but remains in the development phase for most turbine designs and not commercially available for all turbine manufacturers. For this reason, RQL is considered technically infeasible for controlling NO_x emissions from the Mercury 50-6400R turbine.

f. Alternate Lower Fuel Bound Nitrogen (FBN) Fuels such as coal-derived gas or methanol is not practical based on the nature of the Haven Gas Plant project and is therefore deemed technically infeasible for use in the Mercury 50-6400R turbine.

g. XONON utilizes flameless catalytic combustion to limit NO_x formation by reducing the combustion temperature. This technology has been proven to be effective on small turbines (<10 MW) such as the size of the Mercury 50-6400R, but the XONON technology is an emerging technology not commercially available for all turbine manufacturers and still in development phase. For this reason, XONON is considered technically infeasible for controlling NO_x emissions from the Mercury 50-6400R turbine.

h. Dry low NO_x (DLN) burners reduce flame temperature, thus reducing NO_x emissions, by use of two-stage combustor technology. This technology is commercially available on the Mercury 50-6400R turbine. The Mercury 50-6400R turbines units will be supplied with ultra-lean-premix (ULP) dry low NOx technology, which are capable of achieving long-term NO_x emissions of 5 parts per million dry volume (ppmdv) at 15 percent oxygen while firing natural gas. Therefore, DLN is BACT for NO_x for the Mercury 50-6400R turbines.

2. CO BACT

Two types of carbon monoxide control techniques have been identified as applicable to the Mercury 50-6400R turbine:

- Catalytic Oxidation
- Combustion Control

a. The highest level of CO control is catalytic oxidation. A catalytic oxidation system utilizes a passive reactor system that consists of a grid coated with a catalyst. Exhaust from the turbine passes over the catalyst and the CO is oxidized to CO_2. Catalytic oxidation has been technically proven as an effective control alternative for simple cycle combustion turbines. The total capital and annual costs associated with Catalytic oxidation for the Mercury 50-6400R turbine was provided in **Table 12-7** and **Appendix D** of the permit application. The incremental cost effectiveness associated with catalytic oxidation for CO control is $29,700 per ton for the Mercury 50-6400R turbine. As a result, catalytic oxidation is rejected as BACT for CO control on the Mercury 50-6400R turbine.

b. While utilizing good combustion practices, the Mercury 50-6400R turbine can achieve sustained CO emission levels at 10 ppmdv corrected to 15 percent O_2. The lean combustion dry low NO_x control technology (ULP) proposed for reducing NO_x emissions also compensates for CO emissions Given that this is a CO attainment/unclassifiable area and the fact that the predicted maximum impact of CO emissions on the surrounding environment will not be significant, good combustion practices is BACT for CO emissions from the Mercury 50-6400R turbine.

3. $PM_{2.5}$ BACT

Inherently low emissions of $PM_{2.5}$ result from natural gas combustion due to high combustion efficiencies and the clean-burning nature of natural gas. EPA's RBLC database of natural gas fired combustion turbines does not indicate controls for $PM_{2.5}$ beyond good combustion practices. Therefore, good combustion practice is BACT for $PM_{2.5}$ for the Mercury 50-6400R turbine.

C. Waukesha Model VHP-P9390GSI Natural Gas Reciprocating Engine Generator Sets

1. NO_x BACT

Two types of NO_x control techniques have been identified as applicable to the Waukesha Engines:

- Selective Catalytic Reduction (SCR)
- Non Selective Catalytic Reduction (NSCR)

a. SCR uses a reaction with ammonia in the presence of a catalyst to form N_2 and H_2O. NO_x removal of up to 70-90 percent is achievable and the greatest NO_x reduction occurs at catalyst bed temperatures between 400° F and 800°F, for base metal catalyst types (i.e., vanadium-titanium catalysts temperature range 550F-800F) and zeolite-based catalysts systems have been designed to handle exhaust temperatures between 790° F and 1,100°F. The exhaust temperature for each Waukesha Engines will be approximately 1,180°F. This makes the SCR technically infeasible for use with the Waukesha Engines.

b. NSCR uses a three-way catalyst to promote the reduction of NO_x to nitrogen and water, while oxidizing CO and hydrocarbons (HC) to carbon dioxide and water. NO_x removal of 90 percent or greater is achievable with NSCR. This technology is commercially available and is in use on engines comparable to the Waukesha Engines proposed for this project. This makes NSCR technically feasible. The Waukesha Engines shall be equipped with NSCR and the NSCR is BACT for NO_x with an emission limit of 0.1 g/bhp-hr.

2. CO BACT

Two types of NO_x control techniques have been identified as applicable to the Waukesha Engines:

- Non Selective Catalytic Reduction (NSCR)
- Oxidation Catalyst

a. Oxidation Catalysts use chemical oxidation in which CO and HCs are combined with oxygen and water to yield carbon dioxide and water. As such they required excess oxygen and are best designed for lean burn reciprocating engines. The Waukesha Engines proposed for this project are rich burn engines. This makes the Oxidation Catalyst technically infeasible for use with the Waukesha Engines.

b. As previously discussed, NSCR uses a three-way catalyst to promote the reduction of NO_x to nitrogen and water, while oxidizing CO and hydrocarbons (HC) to carbon dioxide and water. CO removal of 90 percent or greater is achievable with NSCR. This makes NSCR technically feasible. The Waukesha Engines shall be equipped with NSCR and the NSCR is BACT for CO with an emission limit of 0.3 g/bhp-hr.

3. $PM_{2.5}$ BACT

Inherently low emissions of $PM_{2.5}$ result from natural gas combustion due to high combustion efficiencies and the clean-burning nature of natural gas. EPA's RBLC database of natural gas fired combustion turbines does not indicate controls for $PM_{2.5}$ beyond good combustion practices. Therefore, good combustion practice is BACT for $PM_{2.5}$ for the Waukesha Engines.

III. BACT Analysis for Carbon Dioxide Equivalents - Greenhouse Gas (CO_2e – GHG)

In accordance with the GHG Tailoring Rule effective July 1, 2011, new stationary sources emitting greater than 100,000 tons per year of CO_2e are subject to PSD requirements and BACT review in accordance with 40 CFR Part 52.21.

The BACT analysis for GHG follows the top-down approach, however, as allowed by 40 CFR Part 52.21 (b)(7), a separate analysis for each emission unit is a general recommendation, but not required. NGP performed a facility-wide as well as process specific BACT analysis for GHG for the proposed project.

A. Facility Wide Strategies were considered and fall into two categories:

- Energy Efficiency Strategies
- Carbon Capture and Sequestration/Storage (CCS)

1. Carbon Capture and Sequestration/Storage (CCS)

Carbon Capture and Sequestration/Storage (CCS) is the only potential add-on technology available and incorporates capturing CO_2 emissions, transporting the CO_2, generally via pipeline, and injecting the CO_2 into subsurface geological formations. Three methods are available for CCS systems: Post combustion systems, Pre-combustion systems, and Oxyfuel combustion systems.

a. Pre-combustion systems

Pre-combustion systems process primary fuel with steam or oxygen to produce a syngas consisting primarily of CO_2 and hydrogen. Once the hydrogen and CO_2 are separated in a secondary reactor, the hydrogen is used as a fuel source and the CO_2 can be removed for sequestration/storage. This technology is designed to be used at facilities utilizing integrated gasification combined cycle (IGCC) technology, such as power plants where coal and petroleum coke are gasified to produce a syngas. This technology would redefine NGP proposed use of natural gas as the primary fuel and would require the facility to install IGCC and utilize other fuels to create a syngas, which seems counterproductive considering the clean nature of firing natural gas. Therefore, pre-combustion systems are technically infeasible for use at the NGP facility.

b. Oxyfuel combustion systems

Oxyfuel combustion systems utilize pure oxygen instead of air, normally used for coal combustion, producing a flue gas consisting of primarily water vapor and CO_2. The flue gas stream is typically greater than 80% CO_2 by volume. The water vapor is then removed by cooling and compressing the gas stream. Oxyfuel combustion is being developed as an alternative to post-combustion controls. The system requires an air separator unit to generate the pure oxygen need for combustion. Currently this technology is in the research phase for combustion turbines and has not been demonstrated in commercial operations on combustion turbines. Therefore, Oxyfuel combustion systems are technically infeasible for use at the NGP facility.

c. Post-combustion systems

The Haven Gas Plant has facility wide PTE for CO_2 of 323,687.32 tpy. NGP reviewed the technical feasibility of post- combustion carbon capture system, which assumes 90% reduction efficiency or a capture reduction for $CO_2$of 291,318.59 tpy. A study level cost analysis was performed and provided in **Table 12-13** and **Appendix D** of the permit application.

d. Transportation

The next step in the process of CCS is transportation of the captured CO_2 to a geological storage site. The most common and efficient mode of transportation is via pipeline. These pipelines operate in the dense phase mode in which there is a continuous progression from gas to liquid and is driven by upstream compression.

e. Storage

The final aspect of the CCS technology is storing the CO_2 in acceptable geological formations such as oil and gas reservoirs, deep saline formations and unmineable coal seams. CO_2 in dense phase is injected into the geological formations and requires existing technology, such as well-drilling, injection technology, computer simulations for storage reservoir dynamics and monitoring application.

f. CCS Economic Analysis

A cost analysis was performed and provided in **Table 12-13** and **Appendix D** of the permit application. The total capital cost for capture technology was calculated to be $120,000,000.00, increasing the total capitalized cost to $150,000,000.00 for the Haven Gas Plant project. The cost of transport to the nearest pipeline, Enid-Purdy Pipeline, was estimated to be $81,810,646.80, but since NGP has no pending contract with the owner of the Enid-Purdy Pipeline, Merit, the calculated cost of storage was conservatively assumed at $0.00. The total incremental cost effectiveness in Dollars/Ton is $157.52 per ton of CO_2 captured, transported and stored.

Although the incremental costs appear economically feasible, KDHE concurs that the capital investment for the size of the proposed operations of this plant is cost prohibitive and therefore CCS is economically infeasible for use at the NGP facility.

2. Energy Efficiency

Energy Efficiency Strategies are techniques or methods which increase energy efficiency through lower-polluting processes/practices, which include energy efficient operational strategies, alternative fuels, process improvements, and add-on controls. The following plant wide energy strategies were considered under the BACT review: Hot Oil System, Electric Compression, and Utility-provided electric power.

NGP is proposing to utilize waste heat recovery from the Titan 250-30000S turbines for a hot oil system. Oil will pass through a heat exchange coil in the exhaust zone of the turbines and will be routed to the amine still reboiler, the mol sieve regeneration heater and demethanizer trim reboiler. This removes the necessity for separate natural gas fired heaters on these units, thereby eliminating GHG that would have been created by additional natural gas fired heaters to operate these essential processes.

Electric compressors will be used for some plant compression activities. One (1) 2,000 hp electric engine will be installed to supply the needed supplemental refrigeration to the cryogenic expansion plant. One (1) 3,500 hp electric engine will be used for inlet compression of low pressure natural gas entering the Haven Gas Plant via the Panhandle Eastern Pipeline.

All turbine compression and electric generating equipment will fire pipeline quality natural gas and utilize good combustion practices. Up to 35% of the electrical power needed to power the facility is planned to be obtained from the existing power utility grid in the area, reducing the need for additional power generating equipment onsite.

B. BACT Analysis for Process Fugitives (FUG-01): Carbon Dioxide Equivalents - Greenhouse Gas (CO_2e – GHG)

The Haven Gas Plant will have numerous equipment components that will have the potential to leak and emit hydrocarbon emissions (CH_4). The total fugitive emissions have been estimated to be 6.62 tpy of CO_2e plant wide and it is estimated that 99% of that total will be emissions from the fugitive sources.
Four types of CH_4 control techniques have been identified as applicable to the Process Fugitives:

- Leakless technology components
- Alternative monitoring – Infrared camera monitoring
- Audio/visual/olfactory (AVO) monitoring program
- Leak detection and repair programs (LDAR)

1. Leakless Technology Components

   Leakless components include bellows valves and diaphragm valves, diaphragm pumps, canned motor pumps, and magnetic drive pumps. Leakless valves and sealless pumps are effective at minimizing or eliminating leaks, but their use may be limited by materials of construction considerations and process operating conditions. A review of BACT/LAER database reveals leakless component technology is not widely applied as a plant wide solution to reducing fugitive equipment leaks. A cost analysis was performed and provided in **Appendix D** of the permit application. The cost effectiveness increment for leakless components on a facility wide basis was $263,750 per ton of CH_4 removed. KDHE concurs that the installation of leakless components on a facility wide basis is cost prohibitive and therefore economically infeasible for the purposes of BACT.

2. Alternative monitoring – Infrared camera monitoring

   Remote camera sensing has been shown to be an effective means of hydrocarbon detection and is considered technically feasible. Alternate monitoring using remote sensing/infrared imaging is an alternative monitoring method to EPA Method 21. The effectiveness is thus likely comparable to EPA Method 21, which is dependent on the frequency of which the observations are conducted.

3. Audio/Visual/Olfactory (AVO) Monitoring Programs

   AVO monitoring can be used to detect leaking fugitive components. Natural gas leaks are expected to have discernible odors that are detectable by olfactory means. In addition, large leaks can be detected by audio and visual means, and secondary visual indications may include condensation around components suspected of leaking. The effectiveness for an AVO inspection program is entirely dependent upon the frequency of observation. This method generally cannot identify leak rates as low as can be detected with instrument monitoring. Therefore, AVO monitoring is effective primarily for identification of large leaks.

4. Leak Detection and Repair (LDAR) Programs

   LDAR programs have been traditionally developed for control of VOC emissions. The fundamental elements for all LDAR programs include: identification of components to be included in the program, conducting routine instrument monitoring of identified components, repair of leaking components and reporting of the monitoring results. A review of RBLC database reveals that LDAR is frequently employed as BACT for fugitive emission monitoring. Monitoring direct emissions of CH4 with traditional portable hydrocarbon monitoring equipment is technically feasible. Therefore, LDAR is BACT for FUG-01.

The compliance group Fug-01 are affected facilities subject to requirements under 40 CFR Part 60 Subpart OOOO which requires compliance with provisions in 40 CFR Part 60 Subpart VVa, therefore compliance with the requirements of 40 CFR Part 60 Subpart OOOO will demonstrate compliance with BACT.

Prior to the publication of 40 CFR Part 60 Subpart OOOO, the compressors proposed to be installed, C-1, C-2a, C-2B, C-3, C-4 and C-5 would have been covered under the requirements of 40 CFR Part 60 Subpart KKK, which referenced compliance with LDAR requirements for compressors under 40 CFR Part 60 Subpart VV. However, 40 CFR Part 60 Subpart OOOO has separate compliance requirements for compressors that do not reference requirements under 40 CFR Part 60 Subpart VVa.

As reciprocating compressors, C-3 and C-5, are subject to requirements under 40 CFR Part 60 Subpart OOOO, therefore these compressors will demonstrate BACT compliance by complying with the applicable requirements of 40 CFR Part 60 Subpart OOOO.

Compressors C-1, C-2a, C-2b, and C-4 are centrifugal compressors using dry seals. According to the Federal Register Volume 77, Number 159 published on Thursday, August 16, 2012, centrifugal compressors with dry seals have no compliance requirements under 40 CFR Part 60 Subpart OOOO. As discussed in the previous paragraph, had the facility remained subject to 40 CFR Part 60 Subpart KKK, these compressors would have been required to participate in a facility LDAR program. Therefore, to ensure these compressors are covered in the LDAR program for BACT compliance, the facility will be required to follow the requirements outlined in 40 CFR Part 60 Subpart VVa, although the regulation is not applicable to the compressors. The reference to 40 CFR Part 60 Subpart VVa will be applied under State Regulation K.A.R. 28-19-302(a).

C. Process Specific Greenhouse Gas (CO_2e – GHG) BACT Analysis Titan 250-30000S Natural Gas Compressor Turbines and Mercury 50-6400R Natural Gas Turbine Generator Set:

Five types of control techniques have been identified as applicable to the combustion turbines:

- CCS
- Selecting higher energy efficient turbines
- Waste heat recovery in the exhaust gases
- Efficient process controls and practices
- Low carbon fuel selection

1. CCS

Carbon Capture and Sequestration/Storage (CCS) previously discussed and deemed to be economically infeasible as capital investment is cost prohibitive.

2. Selecting higher energy efficient turbines; Waste heat recovery in the exhaust gases; Efficient process controls and practices; and Low carbon fuel selection

GHG BACT for the combustion turbines will be incorporation of turbine efficiency, waste heat recovery, efficient process control/practices and low carbon fuels . The Solar turbines selected for natural gas compression and electricity generation are the most efficient and reliable units available. Additionally, EPNs GT-01 and GT-02 will incorporate waste heat recovery in the exhaust streams which will eliminate the need for fired-heaters in the dehydration process, amine unit and demethanizer.

Turbotronic control systems on the Solar turbines monitor engine performance and compression and have heat recovery interface software, backup safety shutdown systems and kW controls. All operations will be performed using good combustion practices in addition to the manufactured recommendations for startup/shutdown operations.

The turbines will burn only pipeline quality natural gas to reduce CO2 emissions. The NGL entering the facility via pipeline is approximately 90% methane (<0.01% of total emissions) and 0.55% CO2.

NGP plan to purchase 35% of the plants electrical power needs from the grid to reduce the need for additional combustion sources at the plant. The turbines will be operated at 100% capacity to ensure combustion efficiency.

Therefore firing pipeline quality natural gas, good combustion practices and efficient process controls and practices is BACT for the Titan 250-30000S Natural Gas Compressor Turbines and Mercury 50-6400R Natural Gas Turbine Generator Set.

The BACT GHG emission rate for each Titan 250-30000S Natural Gas Compressor Turbine is:

134, 606.45 lbs of CO_2/MMScf of Natural Gas Fired
2.27 lbs of CH_4/MMScf of Natural Gas Fired
0.23 lbs of N_2O/MMScf of Natural Gas Fired
134, 724.30 lbs of CO_2e/ MMScf of Natural Gas Fired

The BACT GHG emission rate for the Mercury 50-6400R Natural Gas Turbine Generator Set is:

120, 161.99 lbs of CO_2/MMScf of Natural Gas Fired
2.27 lbs of CH_4/MMScf of Natural Gas Fired
0.23 lbs of N_2O/MMScf of Natural Gas Fired
120, 279.83 lbs of CO_2e/ MMScf of Natural Gas Fired

D. Process Specific Greenhouse Gas (CO_2e – GHG)BACT Analysis for Waukesha Model VHP-P9390GSI Natural Gas Reciprocating Engine Generator Sets

Four types of control techniques have been identified as applicable to the combustion reciprocating engines:

- CCS
- Selecting higher energy efficient engine generators
- Efficient process controls and practices
- Low carbon fuel selection

1. CCS

Carbon Capture and Sequestration/Storage (CCS) previously discussed and deemed to be economically infeasible as capital investment is cost prohibitive.

2. Selecting higher energy efficient engine generators; Efficient process controls and practices; and Low carbon fuel selection

NGP is proposing to install two (2) Waukesha VHP-9390GSI reciprocating IC engines for electricity generation with an approximate generator efficiency of 95.2%. These will be used in conjunction with the Mercury 50-6400R turbine generator (previously discussed). The plant will obtain 35% of its electrical power from existing utility grid. These units were chosen for their generator efficiency, output power and reliability. Additionally, the selection of rich-burn IC engines will allow NGP to add dual catalyst NSCR to reduce emissions of criteria pollutants. These units will be maintained using good combustion practices and manufacturer recommended maintenance in order to promote combustion efficiency and engine life and will burn only pipeline quality natural gas to minimize the combustion of hydrocarbons. Therefore, firing pipeline quality natural gas, good combustion practices and efficient process controls and practices is BACT for the Waukesha engines.

The BACT GHG emission rate for each Waukesha Model VHP-P9390GSI Natural Gas Reciprocating Engine Generator Sets is:

116, 472.25 lbs of CO_2/MMScf of Natural Gas Fired
2.27 lbs of CH_4/MMScf of Natural Gas Fired
0.23 lbs of N_2O/MMScf of Natural Gas Fired
116, 590.10 lbs of CO_2e/ MMScf of Natural Gas Fired

E. Process Specific Greenhouse Gas (CO_2e – GHG) BACT Analysis for Amine Unit

Three types of control techniques have been identified as applicable to the amine unit:

- CCS
- Routing amine vent gases to a control device
- Waste Heat Recovery

1. CCS

Carbon Capture and Sequestration/Storage (CCS) previously discussed and deemed to be economically infeasible as capital investment is cost prohibitive.

2. Routing amine vent gases to a control device

The Haven Gas Plant demethanizer process in the cryogenic expansion operation reduces the mass flow rate of CH_4 to the amine treater, with 0.16 lb/hr of CH4 venting to the amine still or less than 0.001% of the total CO2e emissions. Routing the amine vent gases to a control device, such as a flare or thermal oxidizer, is a technically feasible method and has the potential to further reduce CH_4 emissions; as the destruction of CH_4 would result in the creation of a stoichiometrically equivalent amount of CO_2, which has a lower global warming potential. As demonstrated in **Table 12-14** and **Table 12-15** of the permit application the low BTU values and VOC content of the amine still vent stream, the operation of thermal control device is not feasible without the addition of auxiliary fuel. Additional CO2 from combustion of this auxiliary fuel would result in greater overall CO_2e emissions than the uncontrolled amine still vent stream. Therefore a control device for the CH_4 would be an ineffective means of reducing GHG emissions.

3. Waste heat recovery

As discussed previously, waste heat recover will be in use with the Solar Titan turbines. The waste heat will be used to provide the needed heat input for the plant's hot oil system. The hot oil system, in turn, will eliminate the need for a natural gas-fired amine still reboiler which reduces the plant's potential GHG emissions. This is the BACT method to be used by NGP for reducing GHG emissions at the Amine Still.