pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION
SOUTHWEST REGIONAL OFFICE – AIR QUALITY PROGRAM **MEMO**

TO Air Quality Permit File PA-63-00922D

FROM Alexander Sandy/AS
Air Quality Engineering Specialist
Air Quality Program

THROUGH

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DATE May 28, 2020

RE Plan Approval Application
Robinson Power Company, LLC
Beech Hollow Project / Combined Cycle Gas Turbine Electric Generating Facility
Robinson Township, Washington County
APS # 893311, Auth # 1261667, PF # 650405

Background

On February 8, 2019, the Department received a plan approval application from Burns and McDonnell Engineering Company, Inc. (BMcD) on behalf of Robinson Power Company, LLC (Robinson) to modify the proposed natural gas-fired combined cycle power plant with a nominal capacity of 1,000 MW to be located Robinson Township, Washington County. This site is located just south and west of US Route 22 and State Route 980 respectively (40°24’33”N, 80°17’53”W), and approximately 2.5 miles northeast of the town of Bulger. PA-63-00922D was originally issued on October 27, 2017, and modified on October 4, 2018. Robinson has revised its design plans for the Beech Hollow Energy facility which necessitated revisions to the air quality analysis and submittal of a plan approval application requesting the following changes:

- Update the approved combustion turbines from two (2) 3,051 MMBtu/hr Siemens SGT6-8000H units to two (2) 3,485.8 MMBtu/hr GE 7HA.02 units
    - Increase the operational flexibility of the combustion turbines by lifting the annual heat input limitation and total hours of startup/shutdown
    - Increase the number of startup hours for the combustion turbines
- Increase the size and hours of operation of the auxiliary boiler (from 30 to 91.1 MMBtu/hr)
    - Increase the total hours of operation of the auxiliary boiler
- Add two dew point heaters to support the facility (3.34 and 9.69 MMBtu/hr)
- Increase the natural gas sulfur content limit
- Allow for testing of the fire pump when the combustion turbines are operating
- Revised air quality analysis

Below is the requested modified list of sources for this proposed project:

- Two (2) General Electric 7HA.02 (or equivalent), natural gas-fired combustion turbines, 3,485.8 MMBtu/hr heat input rating (HHV) each; controlled by SCR and oxidation catalysts; 1,000 MW total net generating capacity.
- One (1) natural gas-fired auxiliary boiler, 91.1 MMBtu/hr heat input rating.
- One (1) Cummins, QSX15 (or equivalent), diesel-fired fire pump engine, 411 bhp rating; including one (1) diesel fuel storage tank, 500 gallon maximum capacity.
- One (1) natural gas-fired dew point heater, 9.69 MMBtu/hr heat input rating.
- One (1) natural gas-fired dew point heater, 3.34 MMBtu/hr heat input rating.
- Miscellaneous components in natural gas service, and SF_6 containing switchgear; controlled by leak detection and repair.

This site is approximately 37 acres in size and located adjacent to the Champion Processing Inc. waste coal pile. Previous reclamation efforts included the proposed construction of waste coal-fired circulating fluidized bed boiler (CFB) power plants similar to those operating in Indiana and Cambria Counties for some time now (Seward Generating Station, Ebensburg Cogeneration Plant, and Colver Power Project). The adjacent waste coal pile would have been the primary fuel source and reclaimed over time and the life of the plant. No waste coal CFB was ever constructed at this site, but zoning and site preparation remain in place for an electric generating facility.

PA-63-00922A was originally issued on April 1, 2005, and expiring April 1, 2010, to allow Robinson Power to construct a waste coal-fired CFB power plant with a 272 MW net generating capacity. However, in accordance with 25 Pa. Code §127.13(b), construction must commence within 18 months of issuance of the plan approval and there may not be more than an 18-month lapse in construction. Through site inspections, requested documentation and evidence of construction-related activities, and consultation with United States Environmental Protection Agency (U.S. EPA) Region III; it was determined that the requirements of 25 Pa. Code §127.13(b) had not been met. The Department notified Robinson Power via letter dated January 20, 2010, that "a greater than 18-month lapse in construction has occurred at the Beech Hollow Plant site. Consequently, by operation of law Plan Approval No. 63-00922A has lapsed and is no longer valid." Robinson Power's application to extend PA-63-00922A was returned on February 4, 2010.

PA-63-00922B was originally issued on June 30, 2011, and expiring June 30, 2016, to allow Robinson Power to construct a gas-fired combined cycle power plant with a 147.8 MW gross generating capacity. The primary air contamination source was to be a GE Frame 7EA gas-fired combustion turbine including gas-fired duct burners. No waste coal-fired CFB boiler was proposed or authorized under this plan approval, but Robinson Power was still considering pursuing a waste coal-fired CFB boiler in the future. However, on December 1, 2014, Robinson Power submitted a new plan approval application for a larger plant. In its submittal Robinson Power informed the Department that construction under PA-63-00922B did not commence within 18 months and that the plan approval was no longer valid.

An application for PA-63-00922C was received by the Department on December 1, 2014, and proposed the construction of a natural gas-fired combined cycle power plant with a 668.7 MW gross generating capacity. The primary air contamination source was to be two Siemens SGT6-5000F natural gas-fired combustion turbines including natural gas-fired duct burners. No waste coal-fired CFB boiler was proposed and Robinson Power was no longer considering pursuing a waste coal-fired CFB boiler in the future (to the Department's knowledge). However, on July 7, 2015, Robinson Power formally withdrew its application for PA-63-00922C, stating that a new application [PA-63-00922D] for a larger plant would be submitted in the future.

PA-63-00922D was issued on October 27, 2017. PA-63-00922D was subsequently modified on October 4, 2018, for the removal of the duct burners, modification to the natural gas sulfur limit compliance method, and modification to the annual fuel usage limit. On April 19, 2019, the Department granted an extension of the 18-month construction period in accordance with PA-63-00922D, Section B, Condition #006(c); 25 Pa. Code §127.13(b); and 40 CFR 52.21(r)(2), expiring on October 27, 2020.

This application to modify sources and conditions authorized under PA-63-00922D was received on February 8, 2019, and determined to be administratively incomplete on March 8, 2019, lacking copies of municipal notifications and proof of receipt. The application was determined to be administratively complete on March 28, 2019, including a determination of completeness for the air quality analysis for Prevention of Significant Deterioration (PSD) by Andrew Fleck of the Department's Air Quality Modeling Section.

Notification of receipt and a copy of the application were sent to the EPA, National Park Service (NPS), and the Forest Service (FS) on March 8, 2019. On April 2, 2019, Holly Salazar of the NPS notified the Department that "…The National Park Service has reviewed the proposed application and the Q/D analysis for Shenandoah National Park, we will not be requesting further Class I analysis at this time…" On July 16, 2019, Jeremy Ash of the FS notified the Department that "…Based on the estimated emissions and distances to Class I areas, we anticipate modeling would not show any significant additional impacts to air quality related values (AQRV) at the Class I area(s) administered by the US Forest Service. Therefore, we are not requesting that a Class I AQRV analysis be included in the PSD permit application…"

Additional information was requested from the applicant during the course of this application review. This included revised BACT, LAER, and BAT analyses, supporting vendor information, revised modeling information, additional justification for modifying certain plan approval conditions, and information on the commissioning process for the proposed combined cycle units. All requested information was provided prior to the finalization of this document to address the proposed modifications to this project.

Primary air contaminants of concern from this facility will be NO_x, CO, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, VOC, and CO_2e products of combustion from the natural gas-fired combustion turbines. This will be a Title V facility because potential to emit (PTE) from multiple pollutants will exceed the major source thresholds. As previously determined, due to the potential emissions, the project is subject to PSD for criteria pollutants and nonattainment new source review (NNSR) for NOx. The project will remain below the NNSR major source threshold for VOC of 50 tpy. Below is a summary and analysis of the proposed changes.

Combustion Turbines

The applicant has requested authorization for the installation of two (2) 3,485.8 MMBtu/hr General Electric 7HA.02 (or equivalent) natural gas-fired combustion turbines rather than the previously approved two (2) 3,051 MMBtu/hr Siemens SGT6-8000H units. The proposed increase in capacity does not result in a change to the applicability of any state or federal regulations. However; since the proposed combustion turbines are of a different make and model and of higher capacity than those previously authorized, at the request of the Department, the applicant submitted a revised best available control technology (BACT) and best available technology (BAT) analysis for all pollutants from the proposed GE combustion turbines, and a lowest achievable emission rate (LAER) analysis for NOx from the combustion turbines. The revised analysis was received on June 28, 2019.

LAER/BACT/BAT Summary

LAER for control of NOx has been determined to be installation and operation of dry-low-NOx (DLN) burners and selective catalytic reduction (SCR). Good combustion practices, proper operation and maintenance, and minimization of startup and shutdown events will also be required. The following NOx limits have been determined to comply with LAER:

- 2.0 ppmvd @ 15% O_2 on a 1-hour average, excluding startup and shutdown
- 25.40 lb/hr from each combustion turbine, excluding startup and shutdown
- 229.96 tons combined from the combustion turbines in any consecutive 12-month period

The proposed limit is more stringent than any NOx limit promulgated under 40 CFR Part 60 Subpart KKKK for turbines (of which the lowest is 15 ppm @ 15% O_2). The proposed emission limit is also found to be equivalent to or more stringent than NOx limits found in U.S. EPA's RBLC database for large combined cycle natural gas-fired combustion turbines the Department's internal Combustion Turbine Comparison spreadsheet. NOx emission rates will be higher during startup and shutdown (when the turbine is transitionally operating below the SCR's minimum effective operating temperature) and the combined annual NOx limit represents full time operation with up to 147 total hours of startup and shutdown operation. The proposed limits also reflect the removal of the previously established heat input restrictions which was based on limited operation. According to Robinson, in some instances, the increased hours for startup/shutdown may be required to fulfill future demand. The revised modeling based on the newly proposed annual limits submitted with this application has shown that the increase in startup/shutdown operation from 33.8 to 147 total hours and the removal of the heat input restriction would not cause or contribute to air pollution in violation of the NAAQS[1].

Robinson is required to perform other types of monitoring and testing to demonstrate compliance with the specified short and long-term limits that include: CEMs to monitor NOx and CO emissions; correlation techniques for VOC and HCHO emissions to the CO emissions; fuel usage and fuel analysis records to calculate the SOx, H_2SO_4, and PM, PM_{10}, and $PM_{2.5}$ emissions for each turbine; and ammonia injection rate records for NH_3. These methods of compliance are adequate to determine compliance with the limits. An additional heat input limitation is redundant and will be removed from the plan approval.

BAT for control of NH_3 slip has been determined to be proper design, operation, and maintenance of the SCR control devices for the minimization of NH_3 slip in conjunction with maximization of NO_x reduction to meet the proposed NOx LAER limit. Proper design includes selecting the catalyst material, size, and location such that it is capable of operating within the designed temperature range; and locating and configuring NH_3 injection points to ensure proper mixing of NH_3 with the NOx. Proper operation includes operating the combustion turbines such that the exhaust gas temperature stays within the designed temperature range of the catalyst (500 - 700°F once the exhaust reaches the catalyst, which will be optimized during design according to the application) and injecting sufficient NH_3 to promote the reaction of NOx with injected NH_3. Proper maintenance includes periodic cleaning and/or replacement of the catalyst to keep activity high and promote the reaction of NOx with injected NH_3. The following NH_3 limit has been determined as representative of the application of BAT:

[1] See page 14 of this memo and Attachment A for more information.

- 5.0 ppmvd at 15% O_2

There are no NH_3 limits contained in any NSPS applicable to turbines. The proposed emission limit is found to be equivalent to NH_3 limits applied to other turbines and consistent with other recent BAT determinations for similar sources.

BAT for control of VOC and HAP has been determined to be installation and operation of oxidation catalysts, good combustion practices, and proper operation and maintenance. BAT for HCHO has been determined to be 91 ppbvd @ 15% O_2. The following VOC limits have been determined as representative of the application of BAT:

- 1.0 ppmvd @ 15% O_2 on a 3-hour average, excluding startup and shutdown
- 4.40 lb/hr from each combustion turbine, excluding startup and shutdown
- 41.20 tons combined from the combustion turbines in any consecutive 12-month period

There are no VOC limits contained in any NSPS applicable to turbines. After review of the RBLC and the Department's internal Combustion Turbine Comparison spreadsheets, the BAT limit previously established in this plan approval is still current. Other facilities found in the RBLC database and in Department's internal Combustion Turbine Comparison spreadsheet which were subject to LAER have lower VOC ppm limits, however, it is the Department's understanding that these values have not been verified. Also, note that that this facility is not subject to LAER for VOC and manufacturer guarantees for VOC emission rates for oxidation catalysts can vary manufacturer to manufacturer and case-by-case.

VOC emissions will be higher during startup and shutdown (when the turbine is transitionally operating below the oxidation catalyst's minimum effective operating temperature) and the combined annual VOC limit represents full time operation with up to 147 total hours total hours of startup and shutdown operation (increased from the previous limit of 33.8 hours). The proposed limit is sufficient to ensure that Robinson Power will be a minor facility with respect to emissions of VOC.

BACT for control of PM, PM_{10}, and $PM_{2.5}$; BACT for control of H_2SO_4; and BAT for control of SO_2 has been determined to be combustion of a low ash and low sulfur fuel. Good combustion practices, and proper operation and maintenance will also be required. The following particulate matter, SO_2, H_2SO_4, and sulfur content limits have been determined to comply with BACT and BAT:

- 16.40 lb/hr PM
- 143.66 tons PM combined from the combustion turbines in any consecutive 12-month period

- 16.40 lb/hr PM_{10}
- 143.66 tons PM_{10} combined from the combustion turbines in any consecutive 12-month period

- 16.40 lb/hr $PM_{2.5}$
- 143.66 tons $PM_{2.5}$ combined from the combustion turbines in any consecutive 12-month period

*Filterable and condensable

- SO_2 – 4.10 lb/hr
- H_2SO_4 – 6.10 lb/hr

- Fuel gas sulfur content shall not exceed 0.4 grains per 100 dscf

In order to allow flexibility on the potential source of the fuel gas supply, the applicant has requested to increase the sulfur content limit from 0.2 to 0.4 grains per 100 dscf. With the limit increase, potential SO_2 emissions increase, but facility-wide emissions remain below the PSD threshold of 40 tpy. The proposed sulfur content limit is consistent with other recent plan approvals (e.g. Hill Top Energy Center, PA-30-00233B) and has been determined to be acceptable.

There are no particulate limits contained in any NSPS applicable to turbines and the fuel sulfur content limit is more stringent than any SO_2 limit promulgated under 40 CFR Part 60 Subpart KKKK for turbines (of which the lowest is 26 ng/J or 0.060 lb SO_2/MMBtu heat input). The proposed particulate matter emission limit is found to be consistent with recent determinations, in U.S. EPA's RBLC database for large combined cycle natural gas-fired combustion turbines and recently issued plan approvals for similar sources in Pennsylvania. The fuel sulfur content limit is more stringent than U.S. EPA's definition of pipeline natural gas under 40 CFR §72.2 of the Acid Rain Program general provisions.

BACT for control of CO has been determined to be installation and operation of oxidation catalysts, good combustion practices, and proper operation and maintenance. The following CO limits have been determined to comply with BACT in this case:

- 2.0 ppmvd @ 15% O_2 on a 1-hour average, excluding startup and shutdown
- 15.50 lb/hr, excluding startup and shutdown
- 160.81 tons combined from the combustion turbines in any consecutive 12-month period

There are no CO limits contained in any NSPS applicable to turbines. After review of the RBLC and the Department's internal Combustion Turbine Comparison spreadsheets, the BACT limit previously established in this plan approval is still current. Other facilities found in the RBLC database and in Department's internal Combustion Turbine Comparison spreadsheets have lower CO ppm limits, however, it is the Department's understanding that these values have not been verified. Also, note that manufacturer guarantees for CO emission rates for oxidation catalysts can vary manufacturer to manufacturer and case-by-case.

CO emissions will be higher during startup and shutdown (when the turbine is transitionally operating below the oxidation catalyst's minimum effective operating temperature) and the combined annual CO limit represents full time operation with up to 147 total hours of startup and shutdown operation.

BACT for control of GHG (CO_2e) has been determined to be low carbon fuel, energy efficiency measures, and proper operation and maintenance. CO_2 is the primary GHG pollutant of concern as CH_4 and N_2O emissions account for approximately 0.10% of the turbine CO_2e PTE. Low carbon fuel will include combusting pipeline quality natural gas (high CH_4 content) in the combustion turbines and duct burners. Energy efficiency measures will include designing for maximization of heat exchange within the HRSG, insulation to minimize heat losses, and limiting excess air to the level necessary for complete combustion. Although carbon capture and sequestration is conceptually technically feasible, it has been determined that it remains economically infeasible for this project (see pages 3-17 through 3-28 of Section 3.5 of the plan approval application). The following CO_2e limit has been determined to comply with BACT in this case:

- 850 lbs CO_2/MWh (gross energy output) from all turbines and duct burners combined on a monthly 12-month rolling average

- 3,824,957 tons of CO_2e combined from the combustion turbines in any consecutive 12-month period

The proposed limit is more stringent than any CO_2 limit promulgated under 40 CFR Part 60 Subpart TTTT for electric generating units (of which the lowest is 1,000 lbs CO_2/MWh). The proposed emission limit is also found to be consistent with CO_2 limits found in U.S. EPA's RBLC database for large combined cycle natural gas-fired combustion turbines and recently issued plan approvals for similar sources in Pennsylvania.

Based on the above analysis, the following table lists a summary of the LAER/BACT/BAT analysis for the combustion turbines:

Table 1: Combustion Turbines LAER/BACT/BAT Summary

Pollutant	Control Technology	Emission Limit
NOx	SCR and DLN	2.0 ppmvd @ 15% O_2
CO	Oxidation Catalyst and Good Combustion Practices	2.0 ppmvd @ 15% O_2
VOC	Oxidation Catalyst and Good Combustion Practices	1.0 ppmvd @ 15% O_2
PM	Low Sulfur Fuel and Good Combustion Practices	16.40 lb/hr
PM_{10}	Low Sulfur Fuel and Good Combustion Practices	16.40 lb/hr
$PM_{2.5}$	Low Sulfur Fuel and Good Combustion Practices	16.40 lb/hr
SO_2	Low Sulfur Fuel	4.10 lb/hr
H_2SO_4	Low Sulfur Fuel	6.10 lb/hr
GHG	Energy Efficient Design and Good Combustion Practices	850 lbs CO_2/MWh (gross)
HCHO	Oxidation Catalyst and Good Combustion Practices	91 ppbvd @ 15% O2
NH_3	Good Engineering Practices	5.0 ppmvd @ 15% O2

* See conditions for averaging periods

Auxiliary Boiler

The applicant has requested authorization for the installation of a 91.1 MMBtu/hr natural gas-fired auxiliary boiler rather then the previously approved 31 MMBtu/hr auxiliary boiler. The proposed increase in capacity does not result in a change to the applicability of any state or federal regulations. Since the proposed unit is of larger capacity than the previously approved unit, the Department requested a revised LAER/BACT/BAT analysis. The revised analysis was received on June 28, 2019.

LAER/BACT/BAT Summary

LAER for control of NO_x; BACT for control of CO, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG; and BAT for control of VOC, SO_x, and HAP has been determined to be installation and operation of current generation low-NO_x burners and flue gas recirculation (FGR). Good combustion practices, combustion of a low sulfur fuel, and proper operation and maintenance will also be required. The following limits have been proposed as representative of the above controls for this source of minor significance:

- NO_x – 0.010 lbs/MMBtu (decreased from 0.020 lbs/MMBtu)
- CO – 0.020 lbs/MMBtu (decreased from 0.055 lbs/MMBtu)

On May 18, 2020, the applicant provided information from Cleaver-Brooks via email that auxiliary boiler will also meet 9 ppmdv NOx at 3% O_2 and 130 ppmdv CO at 3% O_2, consistent with Department's draft General Plan Approval and/or General Operating Permit GP-1 for combustion units less than 100 MMBtu/hr.

There are no emission limitations contained in any NSPS applicable to natural gas-fired boilers of this size. Add-on controls such as SCR are not installed on natural gas-fired auxiliary boilers of this size and are not considered feasible considering the limited and unpredictable operating hours for the boiler.

The limit of operational hours of the auxiliary boiler will be increased from 80 to 2,000 hours per year. The revised modeling is based on the increase in capacity and operational hours of auxiliary boiler and demonstrates that facility-wide emissions would not cause or contribute to air pollution in violation of the NAAQS. The plan approval will include the above listed limits and retain the visible emission limitation not to exceed 10% opacity at any time. The initial portable analyzer testing condition in the current plan approval will be replaced with a condition to conduct performance testing consistent with the testing requirement of the Department's draft General Plan Approval and/or General Operating Permit GP-1 for combustion units less than 100 MMBtu/hr as detailed in the Special Conditions of this memo. Additionally, this plan approval will include work practice requirements to conduct an annual tune-up/inspection consistent with the draft GP-1 and detailed in the Special Conditions of this memo.

Dew Point Heaters

The applicant has proposed to install two (2) natural gas-fired dew point heaters that were not included in the previous authorization. Robinson has identified natural gas suppliers for the proposed project and during the design of the gas metering and transportation, it was determined dew point heaters will be needed to heat the gas prior to pressure regulation and transport to the site. Robinson has proposed to install one (1) 9.69-MMBtu/hr (Dew Point Heater 1 – Rover Pipeline) and one (1) 3.34-MMBtu/hr (Dew Point Heater 2 – Harmon Creek Pipeline) dew point heater at the locations where the individual gas lines are regulated and headered together. The dew point heaters will be located off-site approximately 2.74 km WSW of the nearest fence line of the facility (DP1 – 40°24'12.06"N, 80°19'51.37"W; DP2 – 40°24'11.96"N, 80°19'50.99"W). Although the proposed dew point heaters are located offsite, the applicant has requested them to be included as part of this plan approval.

LAER/BACT/BAT Summary

LAER for control of NO_x; BACT for control of CO, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG; and BAT for control of VOC, SO_x, and HAP has been determined to be installation and operation of current generation low-NO_x burners. Good combustion practices, combustion of a low sulfur fuel, and proper operation and maintenance will also be required. The following limits have been proposed as representative of the above controls for this source of minor significance:

- NO_x – 0.012 lbs/MMBtu
- CO – 0.037 lbs/MMBtu

The dew point heaters will be included in the plan approval as source IDs 034 and 035. The plan approval will include the above listed limits and require initial portable analyzer testing to demonstrate compliance.

NSPS from 40 CFR Part 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units will not apply to the dew point heaters. Per 40 CFR § 60.40c(a), this subpart applies to steam generating units less than 100 MMBtu/hr but greater than 10 MMBtu/hr. The proposed dew point heaters are not steam generating units; therefore, this subpart does not apply. Furthermore, the proposed units are less than 10 MMBtu/hr.

NESHAPS Subpart JJJJJJ – for Industrial, Commercial, and Institutional Boilers Area Sources will not apply to the dew point heaters. Per §63.11237, "*Boiler* means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of *Boiler."*

The dew point heaters meet the definition of a process heater, which is excluded from the definition of boiler. As such, Subpart JJJJJJ will not apply.

Other Changes not Elsewhere Addressed

In addition to the proposed changes summarized above related to the equipment updates, in response to the Department's request, the following specific condition changes were also identified in a response received from the applicant dated September 13, 2019. Additional information requested by the Department to support the proposed modifications was received on October 25, 2019, and December 12, 2019.

1. **Section C-IV. Condition #019** – The Beech Hollow Facility is not a major source of HAPs, thus NESHAP Subpart YYYY should not be applicable, as it is only applicable to major sources of HAPs. BMcD requests removal of this citation.

   Response: The Department agrees that the facility is not a major source of HAPs and reference to NESHAP Subpart YYYY will be removed.

2. **Section C-VII. Condition #026** – BMcD has determined that the fire pump diesel tank size will need to be a 500-gallon capacity tank to support fire code requirements. Please update the fire pump diesel tank size Plan Approval language from 100 gallons to 500 gallons.

   Response: The site inventory listed in Condition #026 will be updated to reflect a 500-gallon diesel fuel storage tank. This change will not affect regulatory applicability or any other conditions.

3. **Section D-VI. Condition #008 (Fire Pump)** – The submitted modeling with the major modification and the recently submitted revised modeling analysis modeled the fire pump operating at the same time as the combustion turbines and showed no violation of the ambient air quality standards. As such, BMcD requests removal of this condition as the facility will need to test the fire pump when the combustion turbines are operating.

Response: The Department has verified that the fire pump operating at the same time as the combustion turbines showed no violation of the ambient air quality standards and will remove the restriction of Condition #008 which limited testing of the fire pump engine when the combustion turbines are not in operation.

4. **Section D-VI Condition #002 (~~Circuit Breakers~~ SF_6 Containing Switchgear)** – BMcD requested removal of condition a.(2) from the Plan Approval. Circuit breakers vendors have stated that it is not possible to monitor leaks on a ppm level for circuit breakers located outside. These circuit breakers will be located outside and thus this compliance method is not possible. Beech Hollow will comply with a.(1) for the circuit breakers.

   Response: Condition #002 states:

   The Owner/Operator shall implement a sulfur hexafluoride (SF_6) leak detection and repair (LDAR) program to minimize circuit breaker SF_6 leaks as follows [25 Pa. Code §127.12b]:

   a. Circuit breakers are to be state-of-the-art sealed enclosed-pressure circuit breakers with leak detection equipment that:

      (1) Alerts the operator when 10 wt% of the SF_6 has escaped from any breaker.
      (2) Alerts the operator when a leak exceeds 5,000 ppm SF_6.

   b. When alarms are triggered, the operator shall take corrective action as soon as practicable to repair the circuit breaker units to a like-new state to minimize emissions of SF_6 to the maximum extent possible.

   c. Leaks shall be repaired no later than fifteen (15) calendar days after the leak is detected.

   At the request of the Department, additional supporting information was received via email on December 12, 2019. Rather than removing the additional monitoring requirement, the applicant requested to require that the operator be alerted when the SF_6 reaches a loss of 0.5% over the course of a year (which is equivalent to 5,000 ppm). According to the applicant, SF_6-containing switchgear vendors have stated that it is not possible to monitor leaks on a ppm level for units located outside; however, monitors are available to determine % loss. The Department agrees that the proposed monitoring requirements are acceptable and will modify the condition accordingly.

   Note that the switchgears have the potential to emit SF_6 upon delivery to the facility, which is a regulated GHG. The Department has determined that bringing the SF_6 containing switchgear onsite constitutes commencement of operation due to the potential to emit of a regulated pollutant. In accordance with PA-63-00922D, Section B, Condition #003, Robinson will be required to notify the Department of commencement of operation when the switchgears are brought onsite, beginning the period of temporary operation. Pursuant to 25 Pa. Code § 127.12b (d), temporary operation will be authorized for up to 180 days from commencement of operation. The plan approval will be required to be extended to allow additional periods of temporary operation and completion of construction until the facility has demonstrated compliance with all plan approval conditions and has received a Title V Operating Permit

5. **Section E-III. CEMS Combustion Turbine Unit 1 and Unit 2 (e) CEMS #5** – BMcD requests the removal of the requirement to monitor percent (%) CO_2 from the Plan Approval. Update the Plan Approval to confirm that CO_2 may be determined via Appendix G of 40 CFR Part 75 (example: Equation G-4).

   Response: Consistent with other recent plan approvals for natural gas-fired combined cycle combustion turbines (Hill Top Energy Center, PA-30-00233B; CPV Fairview PA-11-536A; Shell PA-04-00740A; Tenaska, PA-65-00990C), CO_2 CEMS monitoring will be removed. Initial compliance will be required using EPA Reference Method 3A[2] (or another method approved by the Department) and continuous compliance will be required to be based on 40 CFR Part 75 Appendix G[3].

6. **Section E-III. CEMS Combustion Turbine Unit 1 and Unit 2 (e) CEMS #6** – BMcD requests that the Plan Approval be edited to reflect that the CO_2 lb/gross MW-hr is an annual average. It is not appropriate to monitor lb/MW-hr. The calculation of the lb/gross MW-hr should be determined on the same basis as in 40 CFR part 60, Subpart TTTT (annual lbs CO2 divided by the annual gross MW-hr).

   Response: The CEMS requirement for CO_2 will be removed as stated above; therefore, the above referenced condition will be removed. The previously established CO_2 limits are based on gross energy output on a 12-month rolling average. Compliance will be determined as described above.

7. **Section E-I. Combustion Turbines I. Condition #002** – Other facilities with similar conditions that request a correlation between VOC emissions and CEMS-measured CO emissions have had significant issues in correlating the two pollutants due to the very low CO emissions that are actually measured from these large combined cycle facilities. Please change the continuous compliance method for VOC emissions to stack test every five years (congruent with the Title V renewals). Similarly, the same change is requested for continuous formaldehyde compliance; a stack test every five years instead of a formaldehyde/CO correlation using CO CEMs data.

   Response: Upon the request of the Department, BMcD provided the following further justification in the response dated October 25, 2019:

   "Burns & McDonnell has been involved with building and commissioning several new large combined-cycle facilities over the past several years. Based on our knowledge of the performance testing results of these facilities, we have seen that most of the Siemens, GE, and Mitsubishi large frame combustion turbines, when including the removal of CO by the BACT-required oxidation catalysts, result in very little CO emissions, especially at lower loads. Thus, when it is required to generate a curve to correlate emissions of VOC to the emissions of CO, when the CEMS are measuring almost zero pounds of CO per hour, it is extremely difficult to show that there are any VOC emissions at all. An example from a recent project in Maryland had predicted CO emissions between 18 lb/hr and 6 lb/hr depending on ambient conditions and operation with or without duct burners. The stack test resulted in 0.00 lb/hr CO for both of the identical 270-MW combustion turbines. As such, we believe that the initial performance test and CEMs measurements for CO emissions from the Beech Hollow turbines will also be low, making it difficult to create a correlation curve between CO and VOC. As such, we request that VOC compliance be determined via stack testing with every 5-year Title V renewal application."

[2] https://www.epa.gov/sites/production/files/2017-08/documents/method_3a.pdf
[3] https://www.ecfr.gov/cgi-bin/text-idx?SID=4ac181312dcf656bd6f7104b400bf1f1&mc=true&node=ap40.18.75.0000_0nbspnbspnbsp.g&rgn=div9

Emissions curves correlating VOC and CO have been received to the Department for other combined cycle combustion turbines. The requirement will remain unchanged at this time, but may potentially be modified upon site-specific data from Robinson supporting the claim.

8. **Section E-I. Combustion Turbines. Condition #004** – BMcD requests removal of the combustion turbine annual heat input limit from the Plan Approval. This condition is irrelevant now that maximum operations are permitted. Annual emissions are based on 8,760 hours of operation including startup and shutdown emissions.

   Response: As stated above, this requirement is considered redundant and will be removed.

9. **Section E-II. Combustion Turbines. Condition #005** – There is no limit on hexane emissions, therefore, please remove the requirement to test for hexane.

   Response: The Department agrees testing for a pollutant that does not have a limit is not enforceable. The Department also acknowledges the further justification received on October 25, 2019, as stated below:

   "The Comment and Response Document (dated October 27, 2017) that accompanied the final original Plan Approval for the Beech Hollow project, explained the removal of "hexene and pyrolysis fuel oil storage tanks" (Comment 12) as well as explained that hexane is not expected to be emitted from combustion turbines (Comment 16). AP-42 emission factors (Section 3.1- Stationary Gas Turbines) were used to determine HAP emissions from the combustion turbines and hexane is not listed as a HAP from the combustion of natural gas in the combustion turbines. Please refer to the attached final emission estimates for the project in Attachment A which shows that hexane is not a HAP to be emitted from the combustion turbines. As the Comment and Response Document explains, to determine emissions from the natural gas combustion in the originally proposed duct burners, AP-42, Section 1.4 (Natural Gas Combustion for External Combustion Sources) did list hexane as a minor HAP that could be emitted from external combustion sources (or duct burners in this case). The Beech Hollow project does not include duct burners now and as such, there are no expected emissions of hexane from the combustion turbines. We therefore request that the condition that requires testing for hexane emissions from the combustion turbines be removed, as this is not expected to be a significant HAP that will be emitted by the project."

   On October 4, 2018, the Department issued a plan approval modification in which removed the duct burners upon request from the applicant. Upon issuance of the October 4, 2018, plan approval modification, the duct burners are no longer approved sources associated with the project. Hexane emission limits were previously established considering duct burners based conservatively on AP-42 factors. Based on the manufacturer information provided from GE, other recent plan approvals for combined cycle natural gas-fired combustion turbines, and AP-42 Section 3-1, no combustion hexane emissions are expected from the combustion turbines. As such, rather than establishing a limit and testing/compliance methods for hexane, the testing requirement for hexene will be removed, since no hexane emissions are expected. If future evidence indicates hexane from natural gas-fired turbines is of concern, testing may be required.

10. **Section E- IV. Combustion Turbine. Condition #10** – BMcD requests that the definition of startup and shutdown be changed to be defined in a way that is recommended by the combustion turbine vendor

and is easily tracked by CEMs. Startup should include operations up until the turbine is in emissions compliance, which may or may not directly correlate to the catalyst temperature.

Response: Upon the request of the Department, the applicant provided the following additional; information in the response received on October 25, 2019:

"In the draft redlined Plan Approval and corresponding letter to the PA DEP, Robinson Power requested revision of the definition of startup and shutdown for the combustion turbines. Upon review and discussion with the PA DEP, we propose this definition for shutdown, in lieu of the definition proposed in the redlined Plan Approval. "Shutdown – Beginning from the time that shutdown has been initiated in the turbine controls and once any of the HRSG stack emissions are no longer operating within the normal operation values listed in #002 as measured by the CEMS and ending when the fuel is no longer being combusted."

The criteria for the definition of startup/shutdown (SUSD) for natural gas-fired combustion turbines is not explicitly stated in State or federal regulations. Recent plan approvals have included SUSD conditions based upon feasible scenarios provided by the applicant/turbine manufacturer. The definitions for SUSD will be modified based on the proposed language but may be adjusted during the comment period based on any feedback received.

Department Initiated Changes

In addition to the above requested changes, the performance testing requirement will be updated based on the current standard condition which is detailed in the Special Conditions section of this memo. Protocol submittal will be required within 60 days of plan approval issuance rather than 60 days prior to testing.

The condition requiring ERCs to be acquired will also be updated which is explained in the Emission Reduction Credits section of this memo and detailed in the Special Conditions.

Additionally, based on recent information received by the Department for other similar facilities, it has been determined that additional requirements regarding the initial startup/commissioning period are appropriate to adequately account for emissions during that temporary period. On October 10, 2019, the Department met with BMcD at the SWRO to discuss the initial commissioning of the combustion turbines. Due to initial periods of first fire/steam blows prior to the control devices being installed to avoid damage or fouling, additional recordkeeping for accurate emission calculations will be proposed in the draft plan approval.

The following proposed requirements will be included in the draft plan approval:

- During the initial commissioning of the combustion turbines, the Owner/Operator shall maintain the following comprehensive and accurate records:

    a. Total duration of the commissioning period for each combustion turbine.
    b. Duration of operation prior to the installation of the SCR and oxidation catalysts for each combustion turbine.
    c. Load levels and heat input rates during the commissioning process for each combustion turbine.

d. Observations for the presence of visible emission during the commissioning process from each combustion turbine.
e. Methodology for calculating emissions during the commissioning process.

- Operation of the combustion turbines prior to the installation of the SCR and oxidation catalysts shall be minimized to the extent practicable.

Actual emissions during commissioning shall be included in the annual emission reporting required by Section C, Condition #015. This shall include a description of the method used to calculate the emissions and the time period over which the calculation is based, in accordance with 25 Pa. Code 25 § 135.21. Based on the October 10, 2019, meeting with BMcD, the emissions during initial startup/commissioning are expected to be higher than during normal operation once the combustion turbines are tuned, the control devices are installed, and operation is at normal loads.

The facility will be required to comply with the facility-wide PTE limits at all times, including commissioning. No specific commissioning emission limits will be included in this plan approval due to the variability of the process, but all emissions are required to be accurately accounted for. The applicant has proposed to submit the methodology for calculating emissions during the commissioning process 30 days prior to commencement of commissioning the turbines.

Air Quality Modeling Analysis

Due to the proposed changes and additional sources described above, refined air dispersion modeling was performed for the pollutants which exceed the PSD thresholds including CO, NOx, $PM_{2.5}$, PM_{10}, and H_2SO_4; and the analyses were submitted with the plan approval application in order to demonstrate that Robinson Power does not cause or contribute to air pollution in violation of any NAAQS or PSD increments. Input emission rates and stack parameters were found to be consistent with other submitted plan approval application materials. This modeling was evaluated by the Department's Division of Air Resource Management, Air Quality Modeling Section. The Department's technical review concludes that Robinson's revised air quality analyses satisfy the requirements of the PSD regulations. See the "Summary of Air Quality Analyses for Prevention of Significant Deterioration" from Andrew W. Fleck, Environmental Group Manager, dated April 27, 2020, included in Appendix A of this review memorandum. According to the Department's determination, Robinson's source impact analyses demonstrate that the project's emissions will not cause or contribute to air pollution in violation of the NAAQS.

As stated above, in accordance with 40 CFR § 52.21(p), written notice was provided to the FLMs of nearby federal Class I areas as well as initial screening calculations to demonstrate that the facility's emissions would not adversely impact AQRVs and visibility in nearby Class I areas. On March 8, 2019, and July 16, 2019, the Department received notification from the FS and NPS, respectively, that no further Class I analysis will be requested at this time

Facility-wide PTE

Table 2 below summarizes the revised facility-wide potential emissions to account for the above described changes. The emission calculations have been found acceptable and the revised facility-wide totals will be included in this plan approval. Detailed emission calculations are included in Attachment A to the October 25, 2019, revision submitted by BMcD on behalf of Robinson.

Table 2: Revised Facility-Wide PTE

Pollutant	Combined Cycle Combustion Turbines[a]	Aux Boiler[b]	Fire Pump[c]	Circuit Breakers	Dew Point Heaters	Facility-Wide (tpy)
NOx	229.96	0.91	0.13	-	0.68	**231.70**
CO	160.81	1.82	0.12	-	2.11	**164.90**
VOC	41.20	0.49	0.05	-	0.31	**42.00**
HCHO	6.17	6.70E-03	1.80E-04	-	8.60E-05	**6.18**
Total HAPs	15.86	0.17	9.70E-04	-	2.10E-03	**16.03**
Total PM	143.66	0.46	0.007	-	0.36	**144.50**
Total PM_{10}	143.66	0.46	0.007	-	0.36	**144.50**
Total $PM_{2.5}$	143.66	0.46	0.007	-	0.36	**144.50**
H_2SO_4	53.12	0.008	6.44E-03	-	5.14E-03	**53.14**
SO_2	35.92	0.05	0.04	-	0.03	**36.00**
NH_3	205.90	-	-	-	-	**205.90**
GHGs (as CO_2e)	3,824,957	10,668	25	100	6681.9	**3,842,431**

[a] Combustion turbine emissions include startup/shutdown.
[b] Auxiliary boiler emissions based upon 2,000 operational hours per year
[c] Fire pump emissions based upon 100 operational hours per year

Emission Reduction Credits

In accordance with 25 Pa. Code §127.205(4) and §127.210, Robinson Power will be required to secure ERCs at a ratio of 1.15:1 in order to offset potential flue emissions of NOx from the facility. Based on the revised PTE due to the proposed changes, Robinson Power will be required by plan approval condition and regulation under 25 Pa. Code §127.206 to secure the following amount of ERCs which have been certified by the Department prior to commencement of operation:

Table 5: Calculated Offsets, Expressed in Tons

Pollutant/Area	Flue PTE	Ratio	Total ERCs as Offsets
NO_x/Transport Region	231.7	1.15:1	267

According to an email from Joe Pezze of the Hill Crest Group on March 31, 2020, "The ERCs were under an option. We have talked to the supplier who has told us that there are sufficient ERCs out there that we could get a better deal. Once we get to financial closing we will acquire the ERCs and submit a PA Application to incorporate into a Plan Approval."

Per discussions between the Department's SWRO and Central Office on April 2nd and 3rd, 2020, it was determined that the Department's interpretation of the ERC provisions is that in order to operate air contamination sources that emit nonattainment or nonattainment pollutant precursors, the permittee must have the corresponding ERCs in place. Sources that emit attainment or greenhouse gas (GHG) pollutants can commence operation prior to ERCs being secured. PA-63-00922D, Section C, Condition #027 will be revised to clarify that the ERCs for nonattainment and nonattainment pollutant precursors shall be secured prior to commencing operation of nonattainment and nonattainment pollutant precursors emitting sources as detailed in the Special Conditions section of this memo.

Recommendations

Robinson Power Company, LLC has shown that emissions due to the proposed changes and additional equipment will be minimized through the use of appropriate BAT, BACT, and LAER in this application for the natural gas-fired combined cycle power plant to be located in Robinson Township, Washington County. Robinson has also demonstrated that the proposed facility will not cause or contribute to air pollution in violation of the NAAQS, will not impair visibility, soils, and vegetation, and will not adversely affect AQRV, including visibility, in federal Class I areas. Therefore, I recommend issuance of this Plan Approval for a period of 3 years subject to the standard conditions in Section B of all plan approvals along with the following modified/additional special conditions. Other conditions included in PA-63-00922D will remain unchanged.

Modified/New Special Conditions

SECTION C. Site Level Requirements

RESTRICTIONS

#005 The emissions from all sources and associated air cleaning devices installed and operated under this authorization shall not exceed any of the following on a 12-month rolling sum basis:

(a) Nitrogen Oxides (NOx): ~~190.44~~ **231.70** tpy
(b) Carbon Monoxide (CO): ~~142.42~~ **164.90** tpy
(c) Particulate Matter (PM): ~~112.98~~ **144.50** tpy
(d) Particulate Matter with an aerodynamic diameter less than 10 microns (PM_{10}): ~~112.87~~ **144.50** tpy
(e) Particulate Matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$): ~~112.85~~ **144.50** tpy
(f) Sulfur Dioxide (SO_2): ~~15.42~~ **36.00** tpy
(g) Sulfuric Acid Mist (H_2SO_4): ~~7.67~~ **53.14** tpy
(h) Volatile Organic Compounds (VOC): ~~45.42~~ **42.00** tpy
(i) Hazardous Air Pollutants (HAP): ~~12.40~~ **16.03** tpy
(j) Formaldehyde: ~~4.40~~ **6.18** tpy
(k) Ammonia (NH3): ~~170.13~~ **205.90** tpy
(l) Greenhouse Gases, expressed as Carbon Dioxide Equivalent (CO2e): ~~2,931,104~~ **3,842,431** tpy

#008 Sulfur content of the natural gas fuel combusted at this facility shall not exceed ~~0.2~~ **0.4** grains per 100 dscf.

TESTING REQUIREMENTS

#010 (a) The Owner/Operator shall submit two hard copies and one electronic copy of a pre-test protocol to the Department for review ~~at least~~ **within** 60 days ~~prior~~ **of plan approval issuance** ~~to the performance of any EPA reference method stack test~~.

RECORDKEEPING REQUIREMENTS

#013.d. Current grab sample data that demonstrates that sulfur content of the natural gas fuel received at the facility does not exceed ~~0.2~~ **0.4** grains per 100 dscf. The grab sample shall be taken at least once per quarter and determined via laboratory analysis using ASTM D5504 (or equivalent test method).

REPORTING REQUIREMENTS

#019 The Facility is subject to National Emission Standards for Hazardous Air Pollutants from 40 CFR Part 63 ~~Subparts YYYY and~~ Subpart ZZZZ. In accordance with 40 CFR §63.13; copies of all requests, reports, applications, submittals and other communications regarding affected sources shall be forwarded to the Department at the address listed below unless otherwise noted

ADDITIONAL REQUIREMENTS

#026 Air contamination sources and air cleaning devices authorized to be installed at the Facility under this Plan Approval are as follows:

- Two (2) ~~Siemens, SGT6-8000H~~ **General Electric, 7HA.02** (or equivalent), natural gas-fired combustion turbines, ~~3,051~~ **3,485.8** MMBtu/hr heat input rating (~~LHV~~ **HHV**) each; controlled by SCR and oxidation catalysts; 1,000 MW total net generating capacity.
- One (1) natural gas-fired auxiliary boiler, ~~30~~ **90.1** MMBtu/hr heat input rating.
- One (1) Cummins, QSX15 (or equivalent), diesel-fired fire pump engine, 411 bhp rating; including one (1) diesel fuel storage tank, ~~100~~ **500** gallon maximum capacity.
- **One (1) natural gas-fired dew point heater, 9.69 MMBtu/hr heat input rating.**
- **One (1) natural gas-fired dew point heater, 3.34 MMBtu/hr heat input rating.**
- Miscellaneous components in natural gas service, and ~~circuit breakers~~ **SF_6 containing switchgear**; controlled by leak detection and repair (LDAR).

#027 The Owner/Operator shall secure ~~219~~ **267** tons of NOx ERCs. ERCs shall be properly generated, certified by the Department and processed through the registry in accordance with 25 Pa. Code §127.206(d)(1). Upon transfer, the Owner/Operator shall provide the Department with documentation clearly specifying the details of the ERC transaction. This facility may not commence operation **of nonattainment and nonattainment pollutant precursors emitting sources** until the required **nonattainment and nonattainment pollutant precursors** emissions reductions are certified and registered by the Department.

SECTION D. Source Level Plan Approval Requirements (Auxiliary Boiler)

Source Name: NATURAL GAS-FIRED AUXILIARY BOILER (~~30~~ **91.**1 MMBTU/HR)
Source Capacity/Throughput: ~~30.00~~ **91.00**MMBTU/HR
~~29.400~~ **89.300** MCF/HR

RESTRICTIONS

#001 Emissions from the natural gas-fired auxiliary boiler shall not exceed the following:

a. NOx – ~~0.020~~ **0.010** lbs/MMBtu.
b. CO – ~~0.055~~ **0.020** lbs/MMBtu.

#002 Visible emissions from the natural gas-fired auxiliary boiler shall not exceed 10% opacity at any time.

#003 Operation of the auxiliary boiler shall not exceed ~~80~~ **2,000** hours in any consecutive 12-month period.

TESTING REQUIREMENTS

#004 ~~The Owner/Operator shall perform NOx and CO portable analyzer testing upon the natural gas-fired auxiliary boiler according to the requirements of 25 Pa. Code Chapter 139 and EPA conditional test methods of ASTM D6522-00. Portable analyzer testing is required within 180 days of startup of the auxiliary boiler or on an alternative schedule as approved by the Department. Extension to the portable analyzer testing deadline may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified.~~

#TBD **The Owner/Operator shall perform NOx and CO emission testing upon the natural gas-fired auxiliary boiler according to the requirements of 25 Pa. Code Chapter 139. Initial performance testing is required within 180 days of startup of the auxiliary boiler or on an alternative schedule as approved by the Department. Subsequent performance testing is required at a minimum of once every 5 years thereafter. In lieu of performance testing, subsequent emissions verification may be performed using a portable analyzer calibrated and operated according to manufacturer specifications. Extension to initial and subsequent performance testing deadline may be granted by the Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified.**

RECORDKEEPING REQUIREMENTS

#005 The Owner/Operator shall maintain the following comprehensive and accurate records:

a. Hours of operation of the auxiliary boiler on a 12-month rolling sum basis;
b. Fuel type and consumption (expressed in MMscf) of the auxiliary boiler on a 12-month rolling sum;
c. Emission test reports, all operating data collected during tests, and a copy of the calculations performed to determine compliance with emission limitations for the auxiliary boiler; **and**
d. **Records of annual tune-ups/inspections.**

WORK PRATICE REQUIREMENTS

#TBD **The Owner/Operator shall conduct an annual tune-up/inspection of the auxiliary boiler. At a minimum, the tune-up/inspection shall consist of the following:**

a. As applicable, inspect the burner, and clean or replace any components of the burner as necessary;

b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly;

d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with the NOx requirement to which the auxiliary boiler is subject;

e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer as long as it is calibrated and operated according to the manufacturer's recommendations; and

f. Maintain records of the annual tune-up/inspection which shall, at a minimum, include the following:

(1) The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the small combustion unit;
(2) A description of any corrective actions taken as part of the tune-up; and
(3) The date(s) the annual tune-up/inspection was conducted.

SECTION D. Source Level Plan Approval Requirements (Diesel-Fired Fire Pump Engine)

#009 ~~The diesel-fired fire pump engine may only be tested when the combustion turbines are not in operation.~~

SECION D. Source Level Plan Approval Requirements (Switchgear)

#002 The Owner/Operator shall implement a sulfur hexafluoride (SF_6) leak detection and repair (LDAR) program to minimize ~~circuit breaker~~ **switchgear** SF_6 leaks as follows:

a. ~~Circuit breakers~~ **Switchgear** are to be state-of-the-art sealed enclosed-pressure ~~circuit breakers~~ **switchgear** with leak detection equipment that:

(1) Alerts the operator when 10 wt% of the SF_6 has escaped from any breaker.
(2) Alerts the operator when ~~a leak exceeds 5,000 ppm SF_6~~ **the SF_6 reaches a loss of 0.5% over the course of a year**.

b. When alarms are triggered, the operator shall take corrective action as soon as practicable to repair the circuit breaker units to a like-new state to minimize emissions of SF_6 to the maximum extent possible.

c. Leaks shall be repaired no later than fifteen (15) calendar days after the leak is detected.

SECTION E. Group Name: Dew Point Heaters (NEW)

RESTRICTIONS

#001 **Emissions from the natural gas-fired dew point heaters shall not exceed the following:**

a. NOx – 0.012 lbs/MMBtu.
b. CO – 0.037 lbs/MMBtu.

TESTING REQUIREMENTS

#002 **The Owner/Operator shall perform NOx and CO portable analyzer testing upon the natural gas-fired dew point heaters according to the requirements of 25 Pa. Code Chapter 139 and EPA conditional test methods of ASTM D6522-00. Portable analyzer testing is required within 180 days of startup of the dew point heaters or on an alternative schedule as approved by the Department. Extension to the portable analyzer testing deadline may be granted by the**

Department in writing in response to a written request from the Owner/Operator and upon a satisfactory showing that an extension is justified.

SECTION E. Group Name: CEMS (Combustion Turbines)

The requirements for CEMS #5 and #6 to monitor % CO_2 will be removed. The calculation of the lb/gross MW-hr will be determined on the same basis as in 40 CFR part 60, Subpart TTTT (annual lbs CO_2 divided by the annual gross MW-hr).

SECTION E. Group Name: Combustion Turbines

RESTRICTIONS

#002 During normal operation, emissions from each combined cycle combustion turbine shall not exceed the following:

NO_x – 2.0 ppmvd @ 15% O_2
NO_x – 25.40 lb/hr

Compliance Method/Averaging Period:
Initial: U.S. EPA Reference Method 7E.
Continuous: 1-hour block.

CO – 2.0 ppmvd @ 15% O_2 on a 1-hour average.
CO – 15.50 lb/hr

Compliance Method/Averaging Period:
Initial: U.S. EPA Reference Method 10.
Continuous: 1-hour block.

VOC – 1.0 ppmvd @ 15% O_2
VOC – 4.40 lb/hr

Compliance Method/Averaging Period:
Initial: U.S. EPA Reference Method 18 and 25A.
Continuous: 3-hour block based on initial test and VOC to CO correlation.

PM – ~~0.0054 lb/MMBtu~~
PM – ~~18.20~~ **16.40** lb/hr

Compliance Method/Averaging Period:
U.S. EPA Reference Methods 201/201A or equivalent and Method 202.

PM_{10} – ~~0.0054 lb/MMBtu~~
PM_{10} – ~~18.20~~ **16.40** lb/hr

Compliance Method/Averaging Period:
U.S. EPA Reference Methods 201/201A or equivalent and Method 202.

$PM_{2.5}$ – ~~0.0054 lb/MMBtu~~
$PM_{2.5}$ – ~~18.20~~ **16.40** lb/hr

Compliance Method/Averaging Period:
U.S. EPA Reference Methods 201/201A or equivalent and Method 202.

SO_2 – ~~0.00062 lb/MMBtu~~ **4.10 lb/hr**

Compliance Method/Averaging Period:
U.S. EPA Reference Method 6C.

H_2SO_4 – ~~0.00034 lb/MMBtu~~ **6.10 lb/hr**

Compliance Method/Averaging Period:
U.S. EPA Reference Method 8.

HCHO - 91 ppbvd @ 15% O_2

Compliance Method/Averaging Period:
Initial: U.S. EPA Reference Method 320, or ASTM D6348-03 provided that %R as determined in Annex A5 of ASTM D6348-03 is equal or greater than 70% and less than or equal to 130%.
Continuous: 3-hour block based on initial test and HCHO to CO correlation.

NH_3 - 5.0 ppmvd @ 15% O_2 on a 3-hour average.

Compliance Method/Averaging Period:
Initial: U.S. EPA Conditional Test Method CTM-027.
Continuous: 3-hour block.

CO_2 – ~~813~~ **850** lb/MWh (gross energy output) on a monthly 12-month rolling average.

Compliance Method/Averaging Period:
Initial: U.S. EPA Reference Method 3A.
Continuous: 12-month rolling.

*Alternative compliance methods may be approved in writing by the Department.

#003 Total emissions from both combined cycle combustion turbines, including periods of startup, shutdown, **and commissioning** shall not exceed the following on a 12-month rolling sum basis:

NOx – ~~190.~~26 **229.96** tons
CO – ~~142.02~~ **160.81** tons
VOC – ~~45.40~~ **41.20** tons

PM – ~~112.82~~ **143.66** tons
PM_{10} – ~~112.82~~ **143.66** tons
$PM_{2.5}$ – ~~112.82~~ **143.66** tons
SO_2 – ~~15.42~~ **35.92** tons
H_2SO_4 – ~~7.67~~ **53.14** tons
HCHO – ~~4.40~~ **6.17** tons
NH_3 – ~~170.13~~ **205.90** tons
CO_2e – ~~2,930,740~~ **3,842,957** tons

#004 ~~Heat input to both combined cycle combustion turbines, excluding during periods of startup and shutdown, shall not exceed 41,670,370 MMBtu on a 12-month rolling sum basis. This limit may be increased based on actual stack test results with written approval from the Department.~~

TESTING REQUIREMENTS

#004 The Owner/Operator shall perform NOx, CO, VOC ~~(with and without duct firing)~~, PM, PM_{10}, $PM_{2.5}$, **H_2SO_4, SO_2,** HCHO, ~~hexane~~, and NH_3 emission testing…

RECORDKEEPING REQUIREMENTS

#007 The Owner/Operator shall maintain the following comprehensive and accurate records:

a. Hours of operation of each combustion turbine on a 12-month rolling sum basis.
b. Hours of operation of each combustion turbine operating in startup or shutdown on a 12-month rolling sum basis including the date, time, type (cold, warm, hot), and duration of each event.
c. Fuel type and consumption (expressed in MMscf) of each combustion turbine on a 12-month rolling sum basis.
d. ~~Heat input (expressed in MMBtu) to both combustion turbines combined, excluding during startup and shutdown, on a 12-month rolling sum basis.~~
e. Pressure differential across, and inlet and outlet temperature to each oxidation catalyst control device.
f. Inlet temperature to each oxidation catalyst control device on an hourly 4-hour rolling average.
g. Pressure differential across, ammonia injection rate prior to, and inlet and outlet temperature to each SCR control device.
h. Emission test reports, all operating data collected during tests, and a copy of the calculations performed to determine compliance with emission limitations for the combustion turbines.
i. Monitoring information and report data as specified in 25 Pa. Code Chapter 139 Subchapter C and the most recent version of the Department's Continuous Source Monitoring Manual.

#008 **During the initial commissioning of the combustion turbines, the Owner/Operator shall maintain the following comprehensive and accurate records:**

a. Total duration of the commissioning period for each combustion turbine.
b. Duration of operation prior to the installation of the SCR and oxidation catalysts for each combustion turbine.
c. Load levels and heat input rates during the commissioning process for each combustion turbine.

d. Observations for the presence of visible emission during the commissioning process from each combustion turbine.
e. Methodology for calculating emissions during the commissioning process.

WORK PRACTICE REQUIREMENTS

#010 The Owner/Operator may only operate a combined cycle combustion turbine in a defined operating mode. Operating modes of the combined cycle combustion turbines are defined as follows:

Startup – ~~Beginning upon combustion of fuel within the combustion chamber and ending when the SCR catalyst bed reaches its design operating temperature.~~ **Beginning from the time a non-zero value is measured at the HRSG stack (of a permitted pollutant) to the time emissions compliance is achieved at the HRSG stack as measured by the CEMs.**

Shutdown – ~~Beginning when the SCR catalyst bed drops below its design operating temperature and ending when fuel is no longer being combusted~~. **Beginning from the time that shutdown has been initiated and the HRSG stack emissions exceed the normal operation limits and ending when fuel is no longer being combusted.**

Normal – Any time fuel is being combusted other than startup or shutdown.

#011 Startups and shutdowns from each combined cycle combustion turbine shall be limited as follows:

a. Cold start is defined as a restart occurring 72 or more hours after a shutdown. **Cold start period shall not exceed 55 minutes per occurrence.**
b. Warm start is defined as a restart occurring between 8 hours and 72 hours after a shutdown. **Warm start period shall not exceed 40 minutes per occurrence**.
c. Hot start is defined as a restart occurring less than 8 hours after a shutdown. **Hot start period shall not exceed 20 minutes per occurrence.**
d. Duration of each startup and shutdown shall be minimized to the extent possible consistent with manufacturer's procedures.
e. Duration of all startups and shutdowns combined shall not exceed ~~33.8~~ **147** hours in any consecutive 12-month period.

#012 **Operation of the combustion turbines prior to the installation of the SCR and oxidation catalysts shall be minimized to the extent practicable.**

SECTION E. Group Name: NSPS Subpart KKKK (Combustion Turbines)

#002 The Owner/Operator shall comply with the applicable SO_2 limits specified in 40 CFR §60.4330. [Compliance with the natural gas fuel sulfur limit of ~~0.2~~ **0.4** grains/100 dscf will show compliance with this requirement.]

SECTION E. Group Name: NSPS Subpart TTTT (Combustion Turbines)

#001 The Owner/Operator shall comply with the applicable CO_2 gross energy output standard in Table 2 to 40 CFR Part 60 Subpart TTTT [Compliance with the BACT CO_2 limit of ~~813~~ **850** lb CO2/MWh will demonstrate compliance with this requirement].

Appendix A

Summary of Air Quality Analyses for Prevention of Significant Deterioration