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DATE August 25, 2021

RE Technical Evaluation for Case-by-Case NO_x RACT
Keystone Generating Station
Plumcreek Township, Armstrong County
Source IDs 031 and 032, TVOP-03-00027

MESSAGE:

This technical review memorandum outlines the technical evaluation, rationale and preliminary determination for Oxides of Nitrogen (NO_x) and operational requirements for two existing coal-fired combustion units at Keystone Generating Station to include in the Pennsylvania Department of Environmental Protection (PADEP)'s State Implementation Plan (SIP) revision to address Reasonably Available Control Technology (RACT) requirements for the 2008 8-hour National Ambient Air Quality Standard (NAAQS) for ozone.

BACKGROUND:

On April 23, 2016, the Pennsylvania Department of Environmental Protection (PADEP) published 25 Pa. Code §§ 129.96 - 129.100, "Additional Requirements for Major Sources of NO_x and VOCs", commonly referred to as RACT II. 20 Pa.B. 2036. Pursuant to 25 Pa. Code § 129.99, Alternative RACT proposal and petition for alternative compliance schedule, the owner or operator of the Keystone Generating Station has proposed an alternative RACT emission limitation and RACT requirements for two coal-fired electric generating units under 25 Pa. Code § 129.99(d).

FACILITY DESCRIPTION:

Keystone Generating Station operates two bituminous coal-fired combustion units (boilers with steam turbine-driven electric generators (Units 1 and Unit 2)) that provides electricity to the Pennsylvania-Jersey-Maryland (PJM) regional electric grid. Units 1 and 2 are identical units and each have a nominal rating of 8,717 MMBtu/hr with gross electrical output of 910 MW for each generator at nominal maximum operating condition. No. 2 fuel oil is also used for start-up and for as-needed supplemental firing. Unit 1 and Unit 2 are operating as Source ID 031 and 032 respectively in the TVOP-03-00027. Units 1 and 2 are both equipped with ABB-C-E manufactured Low NO_x Burners (LNB) installed in 1995, and Selective Catalytic Reduction (SCR) systems manufactured by Babcock & Wilcox, which were installed in 2003.

Units 1 and 2 are also equipped with DEP certified continuous emission monitors (CEMS) for NO_x and contain exhaust gas stream flow monitors. Since both units are identical and are used for electricity generation, RACT emission limits and operational requirements determined after evaluation and analysis of either unit will apply to both units.

RACT:

In 40 CFR § 51.100, for the purpose of § 51.341(b) - Request for 18-month extension, RACT is defined as devices, systems, process modifications, or other apparatus or techniques that are reasonably available taking into account: (1) The necessity of imposing such controls in order to attain and maintain a national ambient air quality standard; (2) The social, environmental, and economic impact of such controls; and (3) Alternative means of providing for attainment and maintenance of such standard.

In 40 CFR Part 52, EPA has defined RACT as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.
(https://www3.epa.gov/ttn/naaqs/aqmguidance/collection/Doc_0084_VO CFR0917791.pdf)

In 25 Pa. Code §121.1, RACT is defined as the lowest emission limit for VOCs or NO_x that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility.

Therefore, a RACT analysis should consider the technological and economic impacts of controls.

RACT ANALYSIS:

DEP used a top-down approach to determine NO_x emissions limits for coal-fired boilers at the Keystone Generating Station. This included searching and identifying the best methodology, technique, technology, or other means for reducing NO_x while factoring environmental, energy and economic considerations into the analysis. DEP also identified controls installed on identical air contaminant sources in other states.

DEP estimated the capital, installation and annual operating costs of NO_x control using the EPA's OAQPS and Control Cost Manual (Sixth edition) June 12, 2019, and vendor's quotes.

DEP evaluated the cost effectiveness of technically feasible RACT control options and determined that no additional controls are cost effective.

TECHNOLOGY ANALYSIS AND NO_x EMISSION RATE DETERMINATION:

Selective Catalytic Reduction (SCR):

DEP first evaluated the most efficient NO_x reduction technology SCR that is generally used to reduce NO_x emissions from coal-fired boilers. Unit 1 and Unit 2 are already equipped and operating with SCR systems.

SCR systems typically uses a titanium or vanadium catalyst and injection of ammonia or urea at optimum temperature of flue gas to convert the flue gas NO_x to molecular nitrogen (N₂) and water with up to 90% NO_x reduction efficiency. As per EPA's Air Pollution Control technology Fact Sheet (<https://www3.epa.gov/ttnecat1/dir1/fscr.pdf>), the optimum temperature of the flue gas range between 480°F and 800°F, which EPA further refined in response to comments on the Cost Manual that it "concluded that 480°F to 800°F is an "operating" range and that 700°F to 750°F was an optimum temperature range." (https://www.epa.gov/sites/default/files/2020-07/documents/scr_costmanual_7thed_rtc.pdf) .

Flue gas temperature varies at reduced boiler loads and associated electrical generator loads, which for Keystone Units and 1 and 2 are controlled by PJM.

SCR efficiency decreases at lower than optimum flue gas temperature. Ammonia injection at flue gas temperatures less than optimum temperature also become problematic because of formation of ammonium bisulfate (NH₄HSO₄) which deactivates catalyst surface, decreases NO_x reduction efficiency and boiler thermal efficiency and may lead to catalyst plugging, fouling and unplanned boiler shutdown. The original equipment manufacturer ("OEM") of the SCR system established and documented minimum operating parameters for the SCR system, including the inlet temperature to the SCR. The SCR system was designed to operate with a baseload electric generation unit (EGU); i.e. a system with a capacity load, typically operating near maximum heat input for lengthy stretches of time. Given the age of the SCR unit and an absence of any documentation in the record to the contrary, there appears to be no manufacturer's warranty currently in effect and no company analysis of the proper minimum operating conditions appropriate for its current operating mode. Currently, Keystone injects aqueous ammonia into the flue gas stream when it reaches at 612°F, the original set-point established by the OEM.

Based on a review of the ammonia feed rates, fluctuating load and NO_x emission rate, it is clear that any lag in the ammonia feed system is negligible. Ammonia injection rates very closely track load, and the changes in emission rate as the ammonia injection rate follows boiler load fluctuations is minor.

NO_x emission limits on a daily basis:

DEP evaluated and analyzed daily NO_x emissions rates from EPA's Clean Air Markets Division (CAMD) database at varying operating load conditions for Unit 1 and Unit 2 from 2017-2020.

The test results show that at higher load, both units were able to achieve a significantly lower NOx emission rate.

Figure 1 below shows daily operating statistics for Keystone’s Unit 2 during May of 2017. The x axis shows the day of the month while the left y axis correlates with the green line that represents NOx emission rate in lb/MMBtu. The right Y axis is in percentage of the maximum observed heat input. The red line is the percentage of maximum heat input for the unit for the day. The orange line is the percentage of maximum ammonia input observed. The blue line is set at 100% as a reference for the maximum values for the orange and red lines.

As can be seen in Figure 1 below, Keystone’s Unit 2 was able to maintain a NOx rate below 0.06 lb/MMBtu for every day in May of 2017 except for the 31st where the NOx rate increases to about 0.08 lb/MMBtu. In reviewing the hourly data for May 31st, the drop in the average daily rate of ammonia input occurred because the unit heat rate fell below where it had been for the rest of the month during hour 21 of May 31st, and the SCR was shut down for the rest of May 31st.

Figure 1

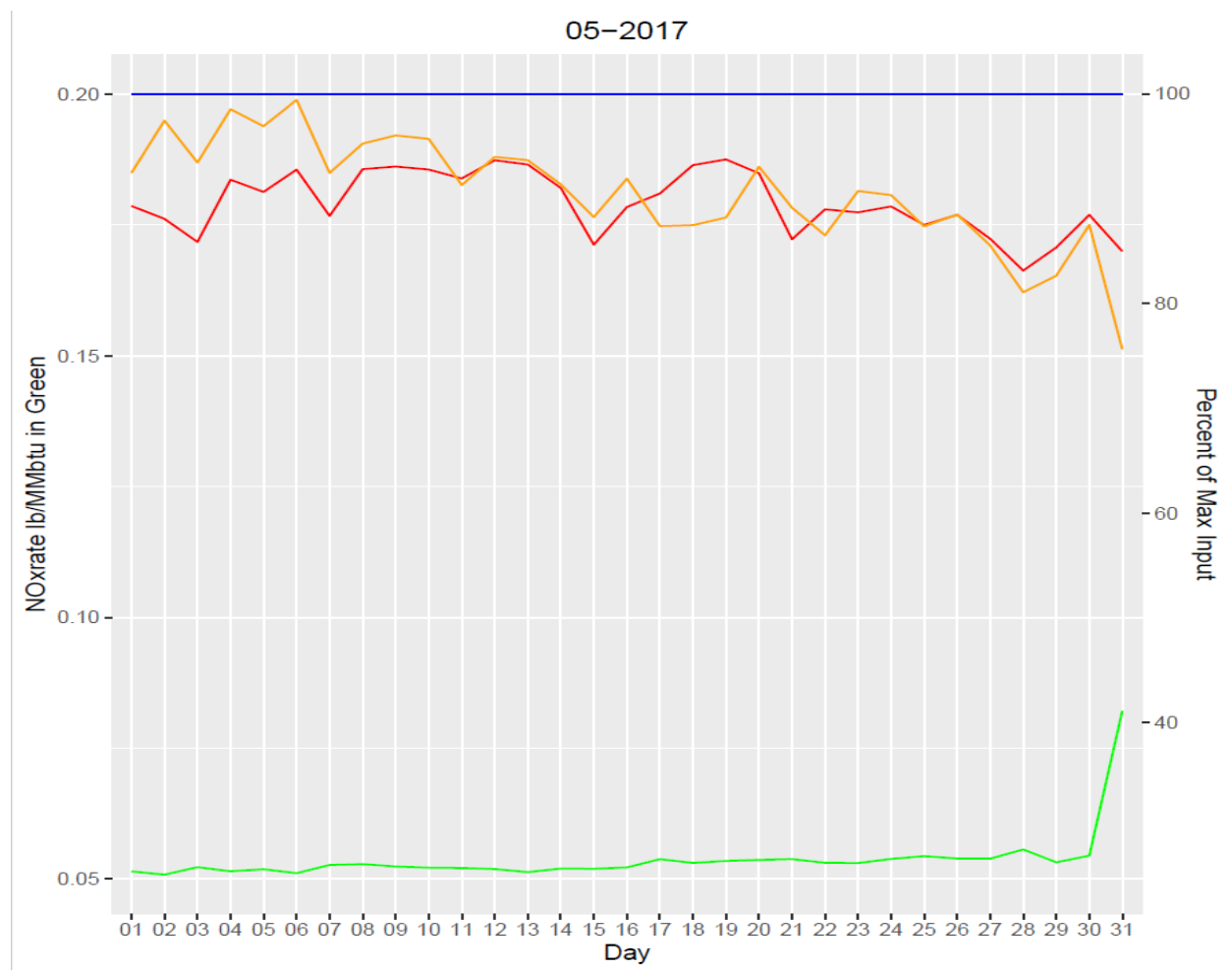


Figure 2 shows daily operating statistics for Keystone’s Unit 1 during May of 2017. During May of 2017 Keystone’s Unit 1 operated at about 0.05 lb/MMBtu from May 1st to May 10th. During May 11th a significant drop in ammonia injection was recorded with a smaller drop-in heat rate from 90% to approximately 80%. Upon review of the hourly data, as can be seen in Graph 3, the cause of this was a drop-in heat rate to about 50-60% during hours 13-18. This caused the SCR to shut down during this period. NOx rates for the rest of the day were around 0.05 lb/MMBtu. Later in the month (from the 15th on) NOx rates increased from 0.05 lb/MMBtu to 0.09 lb/MMBtu because the amount of ammonia injection rate dropped while heat rate was almost constant, indicative of an operator change in the SCR’s set-point.

Figure 2

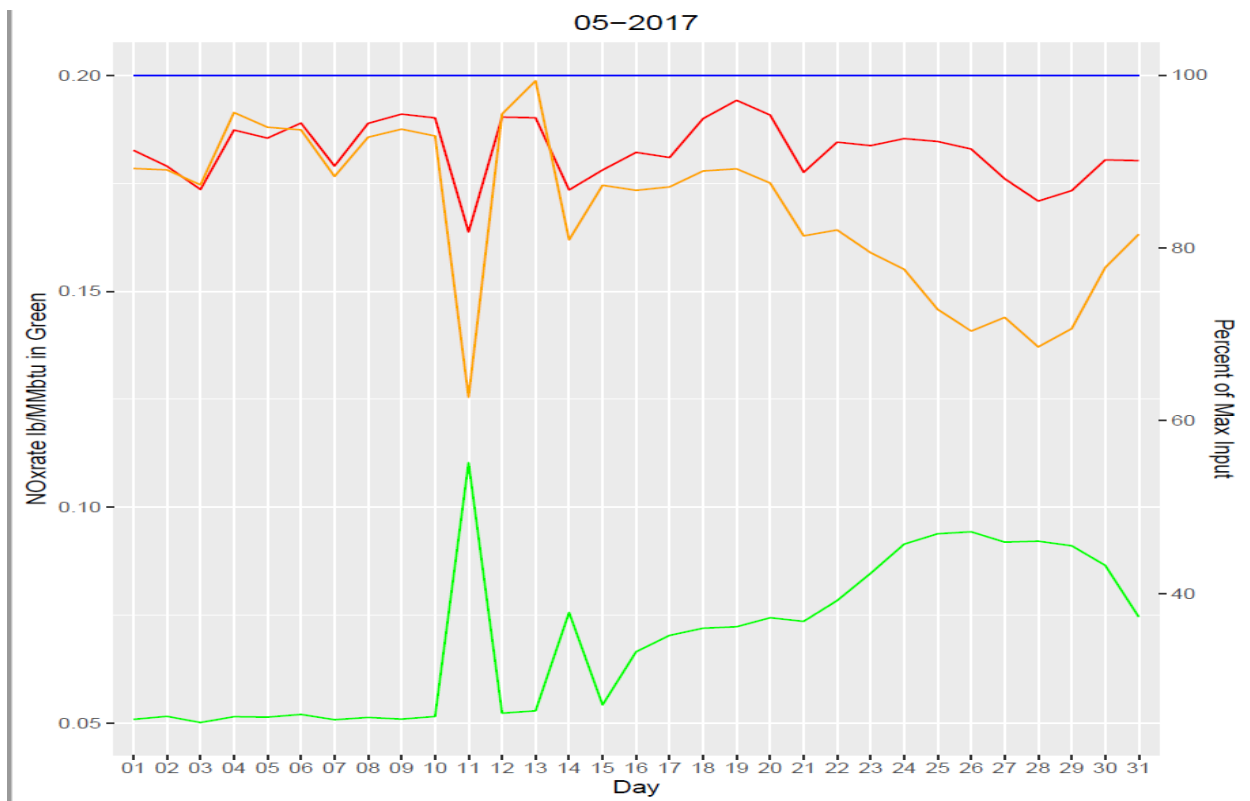
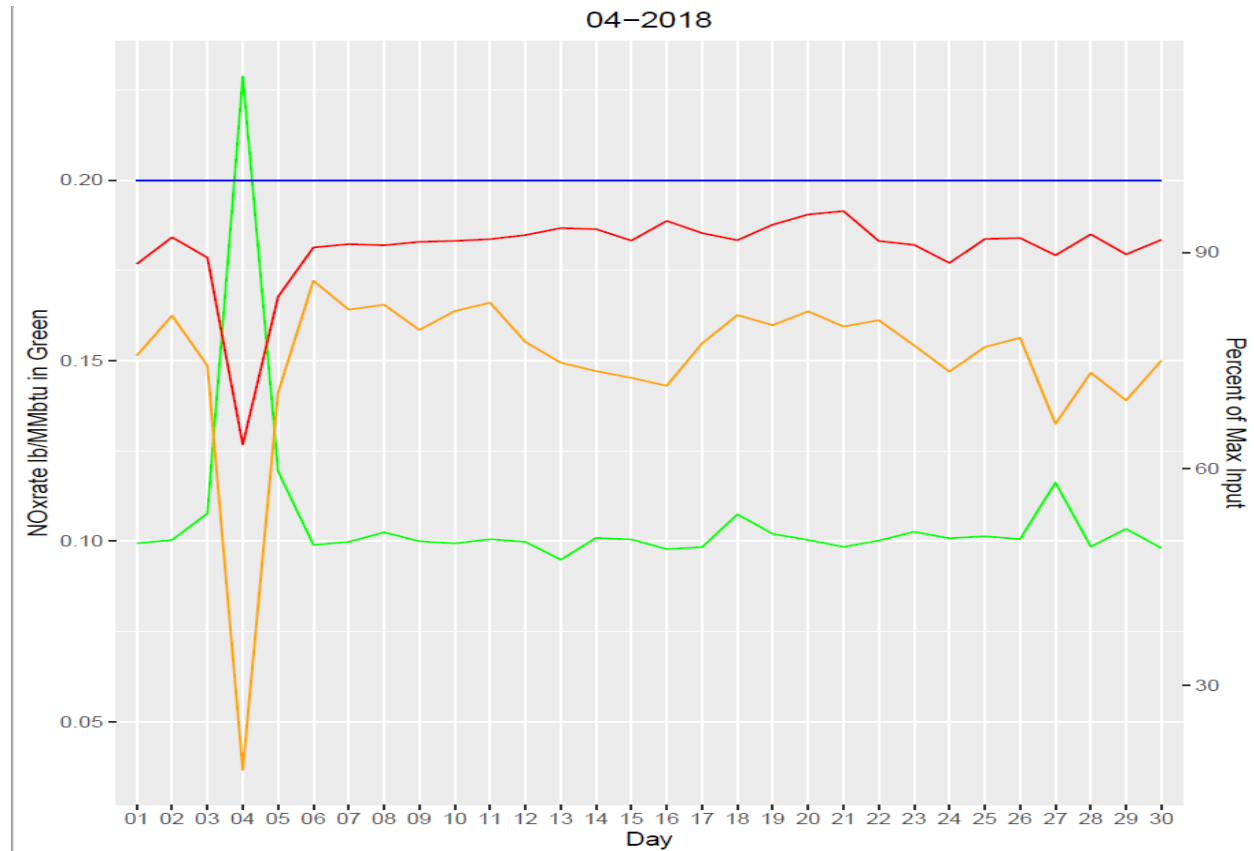


Figure 3 shows daily operating statistics for Keystone’s Unit 1 during April of 2018. During April 6th through the 30th of 2018, Keystone’s Unit 1 operated above 90% load most of the time with no spikes significantly below this level. During this time, they also operated at a NOx level of 0.1 lb/MMBtu and only deviated from that point by more than 0.01 for one day (to about 0.115). When comparing this period to May 2017, less ammonia is being injected relative to the unit’s exhaust volume. This can be seen by observing how much lower the orange line is relative to the red line in April of 2018 (Figure 3) vs May 2017 (Figure 1). This indicates that less ammonia was being injected during April 2018 vs May 2017 relative to the exhaust volume. The

result of injecting less ammonia here is a predictable increase in NO_x emissions relative to May 2017 despite similar consistent high load (mostly over 90%) operations during both these periods. In looking at the hourly data few to no large load swings were observed during April 2018. In addition, the high consistency of NO_x rate, combined with the highly consistent plant load and past lower NO_x rate under similar circumstances, are highly indicative of a system set-point adjustment to a target to 0.1 lb/MMBtu.

Figure 3

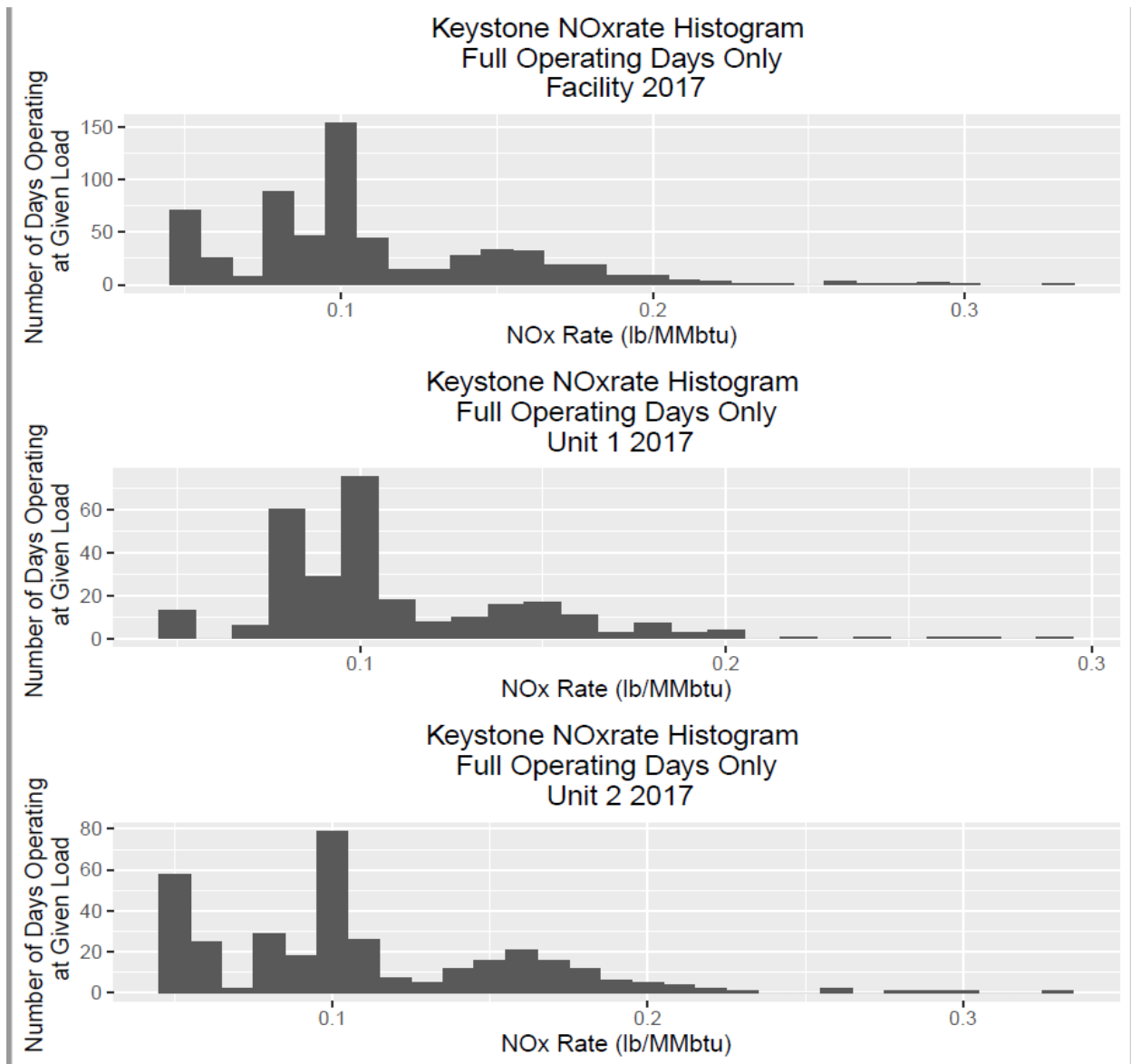


Both units at Keystone seem to be able to achieve a NO_x rate of 0.060 lb/MMBtu on a daily average basis. However, varying load conditions and other factors can and do affect SCR performance and resulting NO_x emission rates. For this reason, DEP recommends a NO_x emission rate of 0.080 lb/MMBtu on a daily average basis with operation of SCR for Unit 1 and Unit 2. This limit excludes, emissions during start-up, shut-down, and malfunction; operation pursuant to emergency generation required by PJM, including any necessary testing for such emergency operations; and during periods in which compliance with this emission limit would require operation of any equipment in a manner inconsistent with technological limitations, good engineering and maintenance practices, and/or good air pollution control practices for minimizing emissions. These exclusions are included in the Maryland regulations for coal-fired electric generating units. [MD COMAR Title 26, Subtitle 11, Chapter 38.04.(4)]. One or more

members of KeyCon LLC also own and operate one or more coal-fired electric generating units with SCR located in Maryland either directly or through a parent and/or subsidiary relationship. The daily NO_x emission rate includes a factor of safety to provide an appropriate compliance margin as well as to account for other factors in the facility's projected future operation.

DEP also evaluated and analyzed daily NO_x emissions rates from EPA's CAMD database at all operating conditions for Unit 1 and Unit 2 from 2017-2020.

Figure 4



As can be seen from Figure 4, in 2017, Unit 1 achieved a NO_x emission rate from 0.05 lb/MMBtu to as high as 0.33 lb/MMBtu on a daily average under all operating conditions with

existing LNB and SCR system. DEP believes that given Keystone's clear targeting of an emission level of 0.1 lb/MMBtu when the SCR is in operation, the achieved NOx emission rate was not representative of an SCR set-point reflective of the equipment's demonstrated capabilities to reduce NOx.

Low NOx Burner upgrade:

Low NOx Burner (LNB) upgrade involves changing the design of a standard burner to enlarge the flame resulting in lower flame temperatures and lower thermal NOx formation which, in turn, results in lower overall NOx emissions. The Keystone units are already equipped with LNB's. Based on information provided in its application, upgrading the existing LNB's to a new burner from R-V Industries could achieve approximately 17% NOx reduction.

Keystone's evaluation of an LNB upgrade found it to be technically infeasible with a cost-effectiveness of \$14,405 tons of NOx removed for Unit 1 and \$18,239 per ton of NOx removed for Unit 2 as shown in the following Tables:

The replacement burners can achieve a 17% NOx reduction (~ 0.22 lb/MMBtu NOx emission rate) when the minimum continuous operating temperature is less than 611°F (i.e., temperature below which ammonia injection into the SCR cannot commence).

Table 6-3 Low-NOx Burner Replacement/Tuning Capital Cost Estimate – Per Boiler

Cost Item	Computation Method	Factor	Cost	Notes
<u>Direct Costs</u>				
Purchased Equipment (PE)	Vendor Quote x factor	1.00	\$1,901,250	Quote provided by R-V Industries, Inc.
Taxes	PE x factor	0	\$0	PE exempt from 6% PA sales tax
Freight	PE x factor	0.05	\$95,063	Table 2.4 of EPA's OAQPS Control Cost Manual, Sixth Edition, January 2002.
Total Purchased Equipment Costs (PEC)	Sum	----	\$1,996,313	PE + Taxes + Freight
Direct Installation Costs	Conemaugh Station Estimate (applicable to Keystone Station as well)	----	\$1,700,000	The budgetary estimate does not consider that all existing dampers on the current burners would need to be replaced, which is an extremely labor intensive effort that is not accounted for in the vendor quote. The listed cost (based on a comparable project) accounts for this omission.
Total Direct Costs (TDC)	Sum PEC + Installation Costs	----	\$3,696,313	
<u>Installation Costs, Indirect</u>				
Engineering / supervision	TDC x factor	0.10	\$369,631	OAQPS Control Cost Manual, Sixth Edition, January 2002
Construction / field expenses	TDC x factor	0.10	\$369,631	OAQPS Control Cost Manual, Sixth Edition, January 2002
Construction fee	TDC x factor	0.10	\$369,631	OAQPS Control Cost Manual, Sixth Edition, January 2002
Start-up	TDC x factor	0.01	\$36,963	OAQPS Control Cost Manual, Sixth Edition, January 2002
Performance test	TDC x factor	0.01	\$36,963	OAQPS Control Cost Manual, Sixth Edition, January 2002
Contingencies	TDC x factor	0.20	\$739,263	Due to the uncertainties associated with the preliminary, budgetary nature of the cost information, a contingency of 20% is warranted.

Cost Item	Computation Method	Factor	Cost	Notes
Modeling and Optimization Studies	Conemaugh Station Estimate (applicable to Keystone Station as well)	----	\$500,000	This budgetary estimate does not consider a critical analysis of potential changes in combustion zone conditions such as lower temperatures, decreased combustion efficiency (related to decreased oxygen availability and resultant increase in carbon monoxide) and increase in corrosion potential around the furnace walls. The listed cost (based on a comparable project) accounts for this omission.
Loss of Revenue Associated with Special Outage Required to Install Equipment	Lost generation x factor	25.00	\$10,710,000	Factor = Estimated generation revenue price (\$/MWh), 28 day outage, 850 MW generation capacity, 75% annual capacity factor
Total Indirect Costs (TIC)	Sum	----	\$13,132,083	
Total Capital Investment (TCI)	Sum TDC + TIC	----	\$16,828,395	TDC + TIC

Table 6-4 Low-NOx Burner Replacement/Tuning Annual Cost Estimate

Cost Item	Computation Method	Factor	Cost	Notes
<u>Direct Operating Costs</u>				
Operating Labor - Operator (OL)	---	---	---	No additional OL costs expected
Operating Labor - Supervision	---	---	---	No additional Supervisory Labor costs expected
Maintenance Labor (ML)	---	---	---	No additional ML costs expected
Maintenance Materials	---	---	---	No additional Maintenance Material costs expected
Total Direct Operating Costs (DOC)	Sum		\$0	
<u>Indirect Operating Costs</u>				
Overhead	(OL + ML) x factor	0.80	\$0	No change from current conditions; i.e., Overhead is included in the current overhead cost of the existing burners
Property Taxes	TCI x factor	0.01	\$168,284	OAQPS Control Cost Manual, Sixth Edition, January 2001

Cost Item	Computation Method	Factor	Cost	Notes
Insurance	TCI x factor	0.01	\$168,284	OAQPS Control Cost Manual, Sixth Edition, January 2002
Administration	TCI x factor	0.02	\$336,568	OAQPS Control Cost Manual, Sixth Edition, January 2002
Capital Recovery ⁽¹⁾	TCI x factor	0.0944	\$1,588,481	Factor per Equation 2.8a of EPA's OAQPS Control Cost Manual, Sixth Edition, 2002. (20 year life and 7% interest rate).
Total Indirect Operating Costs (IOC)	Sum	----	\$2,261,617	
Total Annualized Cost (TAC)	Sum DOC+ IOC	----	\$2,261,617	Per unit
(1) Based on information available from the Station, the firm-specific nominal interest rate for the Keystone Station is at least 7%. A 7% interest rate has been set by the United States Office of Management and Budget (OMB) and is described in the January 2002 EPA Air Pollution Control Cost Manual. Over the years, 7% has been used as a consistent basis for evaluating emission control options for BACT, RACT and BART analyses. As shown in Table 23 on Page 70 in PA DEP's June 2018 Technical Support Document for General Operating Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations (GP-5A) and the General Plan Approval and General Operating Permit for Natural Gas Compression Stations, Processing Plants, and Transmission Stations (GP-5), PA DEP also supports use of an interest rate of 7%.				

Table 6-5 Low-NOx Burner Replacement/Tuning Cost-Effectiveness (\$/ton NOx Removed)

Unit No.	NOx Before Control ⁽¹⁾ (tons/yr)	NOx After Control ⁽²⁾ (tons/yr)	Total Annualized Cost ⁽³⁾ (\$/yr)	Cost Effectiveness (\$ / ton NOx Removed)
1	3,937	3,780	\$2,261,617	\$14,405
2	3,203	3,079	\$2,261,617	\$18,239
Average				\$16,322
(1) Based on CY2019 actual annual emissions. See Table 4-1. (2) Based on available emissions and operating data for CY2019, the LNB upgrades are expected to reduce emissions by 157 tons/year for Unit 1 and 124 tons/year for Unit 2. (3) See Table 6-4 for calculation of annual costs.				

DEP evaluated Keystone's proposed cost analysis and disagrees with aspects of this cost analysis, such as cost associated with modeling and optimization studies that should be a part of installation cost and shouldn't be included separately. Additionally, the Capital Recovery Factor should be calculated at 5.5% at 20 years as recommended in EPA's control cost spreadsheets instead of 7%, and the use of gross lost revenue instead of net loss revenue, which is specifically identified as the proper factor in the US EPA Cost Manual (EPA/452/B-02-001, EPA Air Pollution Control Cost Manual 6th edition, Section 1, Chapter 2, Page 2-30).

DEP independently performed a cost-analysis for replacement of existing LNB with LNB upgrade using the appropriate factors. DEP used an equipment life for LNB at 20 years and an annual interest rate of 5.5 percent to calculate the capital recovery factor and a net lost revenue value of \$3,313,876. Keystone has represented in other written submissions that the facility will not be profitable once the Regional Greenhouse Gas Initiative (RGGI) program is implemented. Net revenue loss is therefore set at the full cost of RGGI credits using Keystone’s data, proportioned over the shutdown period. In other words, this calculation assumes that Keystone’s net loss revenue is equal to its maximum claimed RGGI cost estimates. For a number of reasons, DEP disagrees with Keystone’s claims regarding its potential future RGGI costs, but use of this method of establishing net revenue loss ensures that the calculation is conservative in terms of not under-estimating net loss revenue. Recalculating the costs with revised CRF, lost net revenue and removing cost for modeling and optimization, the DEP determined that the cost-effectiveness for replacement of the existing LNB with an upgraded LNB at \$7,038 for Unit 1 and \$8,911 for Unit 2 per ton of NOx removed was determined to be cost-prohibitive option.

purchased equipment cost	\$1,901,250
freight	\$95,063
installation	\$1,700,000
startup	\$36,963
performance test	\$36,963
contingencies	\$739,263
lost revenue set to cost of RGGI allowances	\$3,313,876
engineering and supervision	\$369,631
construction field expenses	\$369,631
construction fee	\$369,631
Total Capital Investment	\$8,932,271
Annual Cost	
20 year 5.5%	\$747,631
property tax	\$89,323
insurance	\$89,323
admin	\$178,645
total annual cost	\$1,104,922
TPY saved unit 1	157
TPY saved unit 2	124
dollars per ton unit 1	\$7,038
dollars per ton unit 2	\$8,911

cost of RGGI allowances during down period	
cost of RGGI allowances Auction 52 held June 2nd 2021 dollars	7.97
unit size MW	850
down days	28
capacity factor percent	75
2019 CO2 emissions unit 1 tons	6,345,067
2019 CO2 emissions unit 2 tons	5,181,173
2019 power generated unit 1 MWh	6,498,402
2019 power generated unit 2 MWh	5,377,298
average CO2 Emissions tons	5,763,120
average heat input tons	5,937,850
plant efficiency tons CO2 per MWh	0.9705736
tons of CO2 75% 28 days 850 MW unit	415,794
cost of RGGI allowances	\$3,313,876

Boiler operating parameters adjustments:

This option involves making adjustments to the boiler operating parameters that affect the generation of NOx in the boiler fire box. Some changes that can be made to affect NOx generation include excess air levels, secondary air biasing, fuel/auxiliary air damper adjustments, burner tilt, fuel flow biasing, and changes to primary air flows.

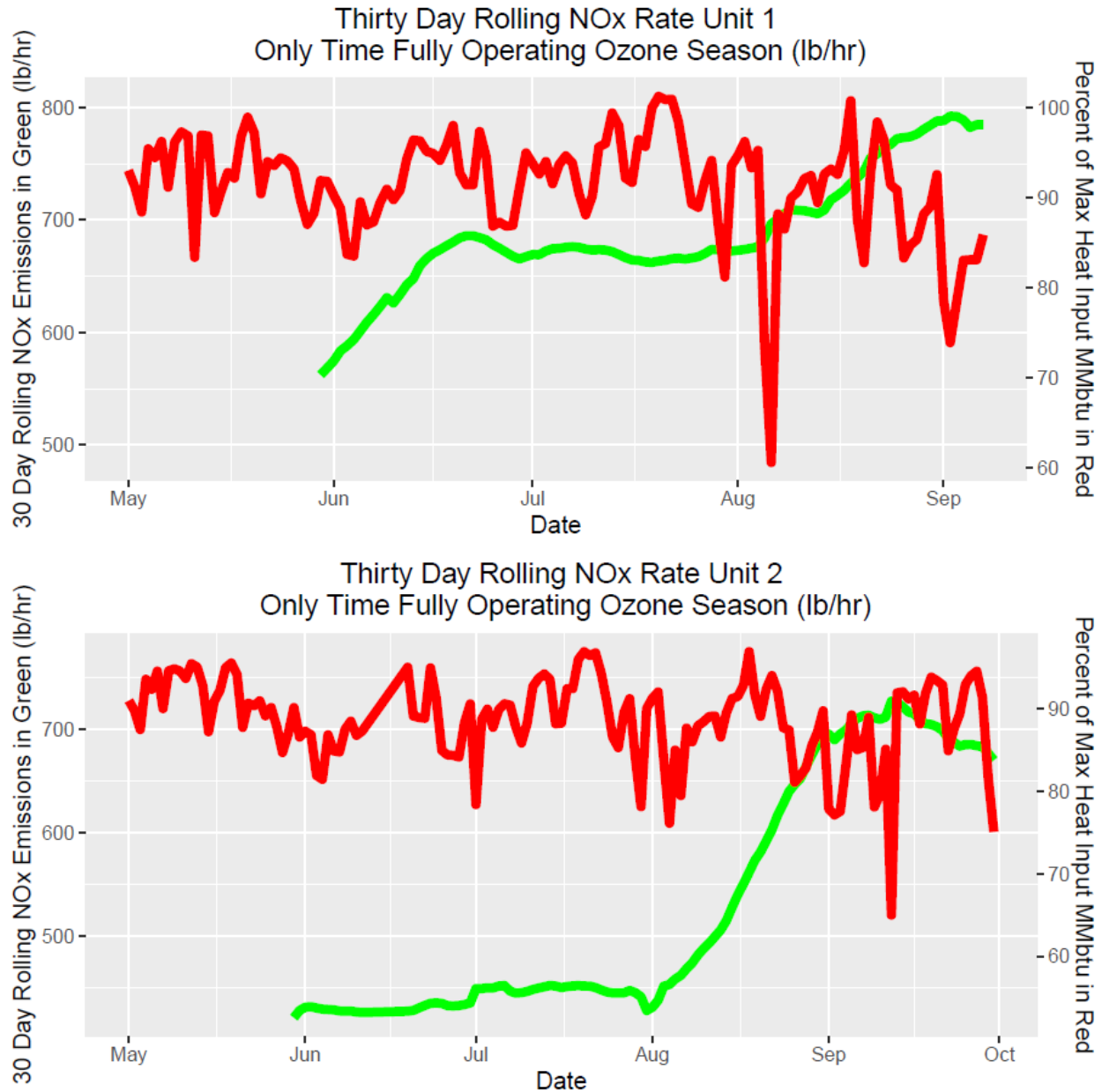
Generally, the regular inspection, preventive maintenance, adjustments to the boiler operating parameters, procedures for shutdown and upset conditions to prevent excess emissions, inspections and testing of Over Fire Air (OFA) components, and/or adjustment of burner angle to minimize NOx emissions results in lowering NOx emissions by 5-15% or at an average of 10%. The changes in the emission rate set-point over time indicate that the boiler has not been tuned to minimize NOx emissions, but rather has been tuned to maximize output. A boiler cannot be simultaneously tuned to achieve both of those goals. Nonetheless, DEP has selected the midpoint of the range of NOx emission reductions.

DEP determined a NOx emission rate of 0.30 lb/MMBtu on a daily average basis at all operating conditions for Unit 1 and Unit 2 as RACT. This value includes an appropriate compliance margin and changes in the boiler utilization.

NOx emission limits on a 30-day rolling average:

DEP also evaluated and analyzed mass-based NOx emission rate in pounds per hour on a 30-day rolling average from EPA’s CAMD database at all operating conditions for Unit 1 and Unit 2 from 2017-2020. Mass based emission rate on a 30-day rolling average is dependent on number of hours a unit is operated, on average, at high load vs low load for the past 30 days.

Figure 5



As per Figure 5, Unit 1 and 2 was operating between 60 to 100% load during ozone season in 2017 and both were able to achieve at or below 800 lbs/hr, on a 30-operating day rolling average basis, continuously. From the CAMD data, DEP believes that by managing combination of hours of operations when a unit is operating at loads supporting SCR and at lower loads with LNB, Unit 1 and Unit 2 can achieve 800 lbs/hr on a 30-operating day rolling average basis despite the changes in utilization of the boiler.

DEP determines a NOx emission rate of 800 lbs/hr on a 30-operating day rolling average basis at all operating conditions for Unit 1 and Unit 2 as RACT.

Selective Non-Catalytic Reduction (SNCR):

SNCR system converts NO_x to its elemental components by injecting either urea or ammonia under high temperature conditions. In this add on control technology, ammonia or urea is injected into the flue gas where the temperature of the flue gas is about 1800°F to 1900°F. At this temperature, NO_x and the ammonia or urea react to form nitrogen gas and water. There is a great deal of temperature sensitivity in this reaction and since the urea or ammonia are often injected as aqueous solutions, there is an energy penalty on the overall boiler efficiency from vaporizing the water. Relatively small concentrations of ammonia result from the use of this NO_x control. This system typically provides for 20% reduction in NO_x emissions.

Unit 1 and Unit 2 already use LNB and SCR. SNCR efficiency is low when emissions are well controlled by combustion controls. SNCR may not be technically feasible due to frequent load changes. SNCR is not likely to provide a significant emission reduction due to frequent load variations and the existing controls.

DEP determines SNCR technology to be technically infeasible option for Unit 1 and Unit 2.

Switching to natural gas:

The Keystone generating station does not have access to an adequate natural gas supply. Installing a pipeline may make this option extremely expensive. As per Keystone's proposal, the natural gas pipeline cost and unit conversion cost together would be approximately \$160 million. Conversion of the units from coal to natural gas would result in a ~ 30% heat rate penalty, which would impact the economic viability of the units for dispatch.

DEP believes that cost-effectiveness of switching coal-fired units to natural gas-fired units and installing a new pipeline would exceed the cost-effectiveness benchmark and therefore determines conversion to natural gas option as economically infeasible option.

Conversion to solar or wind power:

Replacing coal-fired units with solar or wind power units would require acquisition of large land areas and associated permitting issues. DEP determines conversion of coal-fired power plant to solar or wind power plant option as technically and economically infeasible.

Oxygen enhanced combustion:

An oxygen enhanced combustion system uses a cryogenic process to supply pure oxygen; atmospheric-pressure combustion for fuel conversion in a conventional supercritical pulverized-coal boiler and substantial flue gas recycle making it cost-prohibitive for large coal units. This technology hasn't been demonstrated on coal-fired boilers. DEP determines oxygen enhanced combustion as technically infeasible option.

Flue gas recirculation (FGR):

Flue gas is used as a thermal diluent to reduce combustion temperatures in FGR system. Flue gas is withdrawn after the economizer or air heater and re-admitted through the burner windbox. This technology reduces thermal NO_x and is not applied to coal-fired EGU boilers because NO_x

emissions from coal-fired boilers are primary fuel NO_x and the flue gas contains relatively high concentrations of ash. DEP determined that the FGR system is a technically infeasible option.

Rotating opposed fire air (ROFA):

In the ROFA system, gases are set within the furnace into rotation via an asymmetric boosted over-fire air system which reduces NO_x emissions. Unit 1 and Unit 2 are tangentially fired boilers with separated overfire air. Tangential firing involves injecting fuel and air at a certain angle in the corners of the furnace that allows for imparting rotation to the reacting jets of fuel and air. ROFA is similar to tangentially fired technology that is already used in Unit 1 and Unit 2.

SCR optimization:

The owner or operator of Keystone Generating Station will be required to work closely with the SCR catalyst vendor to monitor SCR performance in accordance with the catalyst management plans (CMPs) developed for the SCR systems.

Economizer bypass:

The owner or operator of Keystone Generating Station has evaluated the possibility of bypassing the economizer during boiler's low load operation, startup and shutdown to allow SCR operation. Keystone has considered the economizer bypass option as a technically infeasible option due to interference from the main coal feed belts and also retrofit of an economizer bypass would encounter more issues. DEP has determined the economizer bypass as a technically infeasible option.

V-temp system:

The V-temp system reduces heat absorption by the economizer during reduced boiler operating load conditions, thus increasing the flue gas temperature at the downstream SCR. However, it also negatively impacts boiler efficiency, specifically at varying load operations. The V-Temp system is installed on boilers at Conemaugh Generating Station. The V-Temp system was in-service during the 2017 and 2018 ozone seasons, but not during the 2019 ozone season because PJM specifies the minimum electrical outputs from Conemaugh generating units and data for 2019 shows that the electrical output for both units swings on nearly a daily basis from near minimum sustainable load to full operating load. Such swings in operating load result in the engaging / disengaging of the V-Temp system twice (and sometimes more times) per day. The quantity of thermal inertia associated with the engaging / disengaging of the V-Temp system in a short time period results in deleterious effects on boiler and fuel / air / water systems and creates difficulties with maintaining operations that help avoid unplanned boiler trips.

PJM also specifies the electrical outputs from Unit 1 and Unit 2 at Keystone Generating Station, which may result in both boilers operating at varying loads. DEP determines installation of V-temp system on Unit 1 and Unit 2 at Keystone generating station as a technically infeasible option for RACT determination.

Flue gas reheat:

Flue gas reheat during low load, startup and shutdown increases the flue gas temperature making operation of SCR technically feasible at low load operations. The option involves the

installation of burners, dilution air fans and ductwork near the economizer exits to reheat the flue gas. As per owner or operator of Keystone Generating Station, three 130 MMBtu/hr burners with an equipment footprint of 56 ft by 36 ft would be required in order to provide reheat at lower load operations. Due to the size and weight of this equipment, the required elevation, and interferences from existing equipment, this option is not technically feasible. DEP concurs with Keystone's analysis and determines flue gas reheat system as a technically infeasible option for installation of three 130 MMBtu/hr burners with an equipment footprint. The Keystone application does not include an analysis of partial flue gas reheat using one or two 130 MMBtu/hr burners, nor does it analyze other heat inputs. Clearly, any additional flue gas reheat will have a beneficial effect on NO_x emission rates, and Keystone will be required to submit an engineering analysis, within 180 days of the effective date of this permit, evaluating partial flue gas reheat.

Dry sorbent injection:

SCR systems cannot be operated at select low loads due to deposition of ammonium sulfate and ammonium bisulfate formed by ammonia reacting with SO₃. Dry sorbent injection before the SCR uses sodium carbonate to reduce SO₃ concentrations and prevent the formation of ammonium sulfate and bisulfate. The station has concerns about the increase in particulate loading across the SCRs and downstream electrostatic precipitators (ESPs), which would likely result in increased induced draft fan blade wear and accelerated blade replacement. The presence of SO₃ in the flue gas stream is also desirable because it results in enhanced particulate capture by the Electrostatic Precipitator (ESP).

An SO₃ mitigation system is already installed on both units at Keystone Generating Station just before the flue gas desulphurization (FGD) systems to control SO₃ / H₂SO₄ emissions from the FGDs.

Compliance demonstration, Recordkeeping, Monitoring and Reporting requirements:

The facility shall demonstrate compliance with NO_x emissions limits using existing Continuous Emissions Monitoring System (CEMS). The facility shall comply with recordkeeping, monitoring and reporting requirements as set forth by NWRO in the Title V Operating Permit. These requirements shall apply to emission limits, the emissions rate and other records as specified by NWRO for the facility. The records shall be reported to the program on the schedule specified by NWRO in the permit. §127.12(a)(3), §127.411(a)(4)(i), §127.12b(c), §127.441, §127.442 and §127.511.

NO_x RACT emission limits for Unit 1 and Unit 2:

DEP concludes that the following NO_x emissions limits are reasonable and to be incorporated in RACT permit as they reflect control levels achieved by the application of existing control technologies and after considering both the economic and technological analysis of other NO_x mitigations measures.

- (1) Emissions of NO_x expressed as NO₂ for Units 1 and 2 are individually limited to a maximum of 0.080 lb NO_x /MMBtu on a daily average basis. This limit excludes, emissions during start-up, shut-down, and malfunction; operation pursuant to emergency

generation required by PJM, including any necessary testing for such emergency operations; and during periods in which compliance with this emission limit would require operation of any equipment in a manner inconsistent with technological limitations, good engineering and maintenance practices, and/or good air pollution control practices for minimizing emissions.

Startup means: The period in which operation of the EGU is initiated after a shutdown event for any purpose. Startup ends when any of the steam from the boiler is used to generate electricity for sale over the grid or for any other purpose (including on-site use). Any fraction of an hour in which startup occurs constitutes a full hour of startup.

Shutdown means: The period in which cessation of operation of an EGU is initiated for any purpose. Shutdown begins when the EGU no longer generates electricity or when no fuel is being fired in the EGU, whichever is earlier. Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown.

Daily average means: The total mass for each of the hours during the calendar day divided by the total heat input for each of the hours during the calendar day. This calculation methodology would also apply to the limit contained in (2), below.

- (2) Emissions of NO_x expressed as NO₂ from Unit 1 and 2 are individually limited to a maximum of 0.30 lb NO_x /MMBtu on a daily average basis under all operating conditions.
- (3) Emissions of NO_x expressed as NO₂ from Unit 1 and 2 are individually limited to a maximum 800 lbs NO_x/hr on a 30-operating day rolling average basis under all operating conditions.
- (4) The owner or operator shall calibrate, operate, and maintain all elements of the SCR system and units in accordance with the manufacturer's specifications, in a manner consistent with good engineering and air pollution control practices when the SCR system is in use.
- (5) The owner or operator shall operate and maintain LNB in accordance with the manufacturer's specifications and in a manner consistent with good engineering and air pollution control practices. 127.441 (do not SIP).
- (6) The owner or operator shall maintain NO_x controls as effective as reasonably possible during startups and shutdowns.
- (7) The owner or operator shall take steps to bring NO_x controls back into full service as quickly as practicable whenever the control equipment experiences a malfunction.
- (8) The owner or operator shall document and report to the DEP, information regarding the cause of the malfunction and the steps for bringing the controls back.

- (9) All operators of Unit 1, Unit 2, SCR, and LNB shall be trained in the operation and maintenance of the unit(s) they are assigned to operate by qualified personnel. 127.441 (do not SIP).
- (10) The owner or operator shall develop, maintain and implement an operation and maintenance plan (O&M Plan) for Unit 1 and Unit 2 and the SCR. The O&M Plan shall include, but not be limited to the following:
- (a) Inspection, repairs, and preventive maintenance procedures to be followed to ensure proper operation of the Unit 1 and Unit 2 and SCR system and continuing compliance with the applicable emission limits specified in this Permit.
 - (b) A description of preventive maintenance schedules, spare parts inventories, procedures and protocols for unscheduled outages, and provisions for equipment replacement and measures to be taken to protect SCR system in the event of failure or shutdown.
 - (c) Inspections of duct work and boiler casing and repairs of leaks to maintain flue gas temperature.
 - (d) Details of the practices and procedures to be followed during periods of startup, shutdown and upset conditions in order to prevent emissions in excess of the standards specified in this permit.
- (11) The owner or operator shall develop, maintain and implement an operation and maintenance plan (O&M Plan) for Unit 1 and Unit 2 and LNB. The O&M Plan shall include, but not be limited to the following:
- (a) Inspection, repairs, and preventive maintenance procedures to be followed to ensure proper operation of the Unit 1 and Unit 2 and LNB and continuing compliance with the emission standards specified in this Permit.
 - (b) A description of preventive maintenance schedules, spare parts inventories, procedures and protocols for unscheduled outages, and provisions for equipment replacement and measures to be taken to protect air pollution control equipment in the event of any control equipment failure or shutdown.
 - (c) Details of the practices and procedures to be followed during periods of startup, shutdown and upset conditions in order to prevent emissions in excess of the standards specified in this permit.
 - (e) Inspections, repair and testing of Over Fire Air (OFA) components.

- (f) Details of the practices and procedures to be followed to ensure that the boiler is tuned to optimize NO_x reduction over combustion efficiency, including but not limited to the properly adjusted burner angle.
- (12) The facility shall tune the boiler to minimize NO_x emissions within 6 months of the effective date of this permit. 127.441 (do not SIP).
- (13) The facility shall tune the boiler to minimize NO_x emissions annually after the initial boiler tuning. 127.441 (do not SIP)
- (14) Within 3 months of the effective date of this permit, the facility shall set the SCR at a target NO_x emission rate of 0.060 lb. NO_x per MMBtu. 127.441 (do not SIP)
- (15) After operating the SCR with an outlet NO_x emission rate set-point of 0.06 lb per MMBtu for twelve consecutive months, the facility shall submit an engineering study within 180 days that analyzes the overall environmental performance of the system at that set-point. 127.441 (do not SIP)
- (16) During the 60 days of each calendar year, the facility shall perform a catalyst activity test.
- (17) Within 60 days of receiving the results of catalyst activity test, the facility shall consult with the SCR catalyst vendor to monitor SCR performance in accordance the catalyst management plans (CMPs) developed for the SCR systems.