pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

MEMO

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THROUGH	Mark Hammond MCH 9/28/2021 Director, Bureau of Air Quality
DATE	September 28, 2021
RE	Technical Evaluation for Case-by-Case NOx RACT Conemaugh Generating Station West Wheatfield Township, Indiana County Source IDs 031 and 032, TVOP-32-00059

MESSAGE:
This technical review memorandum outlines the technical evaluation, rationale and preliminary determination for Oxides of Nitrogen (NOx) and operational requirements for two existing coal-fired combustion units at Conemaugh 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 NOx 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 Conemaugh 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:
Conemaugh 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 8,280 MMBtu/hr with gross electrical output of 936 MW for each generator at nominal maximum operating condition. Natural gas 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-32-00059. Units 1 and 2 are both equipped with Low NOx Burners (LNB), and Selective Catalytic Reduction (SCR) systems.

Units 1 and 2 are also equipped with DEP certified continuous emission monitors (CEMS) for NOx 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/aqmguide/collection/Doc_0084_VOCFR0917791.pdf)

In 25 Pa. Code §121.1, RACT is defined as the lowest emission limit for VOCs or NOx 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 NOx emissions limits for coal-fired boilers at Conemaugh Generating Station. This included searching and identifying the best methodology, technique, technology, or other means for reducing NOx while factoring environmental, energy and economic considerations into the analysis. DEP also identified controls installed on similar air contaminant sources in other states.

DEP estimated the capital, installation and annual operating costs of NOx 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 NOX EMISSION RATE DETERMINATION:
Selective Catalytic Reduction (SCR):
DEP first evaluated the most efficient NOx reduction technology SCR that is generally used to reduce NOx 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 NOx to molecular nitrogen (N2) and water with up to 90% NOx reduction efficiency. As per EPA's Air Pollution Control technology Fact Sheet (https://www3.epa.gov/ttncatc1/dir1/fscr.pdf), the optimum temperature of the flue gas range between 480^{o}F and 800^{o}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. Each Unit at Conemaugh Station is required to provide the minimum electric output called for by PJM, the grid operator. Failure to provide the minimum load subjects the facility to substantial penalties, while the price paid for providing excess electricity is minimal.

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 (NH_4HSO_4) which deactivates catalyst surface, decreases NOx 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, Conemaugh injects aqueous ammonia into the flue gas stream when it reaches at 612°F, the original set-point established by the OEM under an operating scenario of near constant operation at or near maximum load.

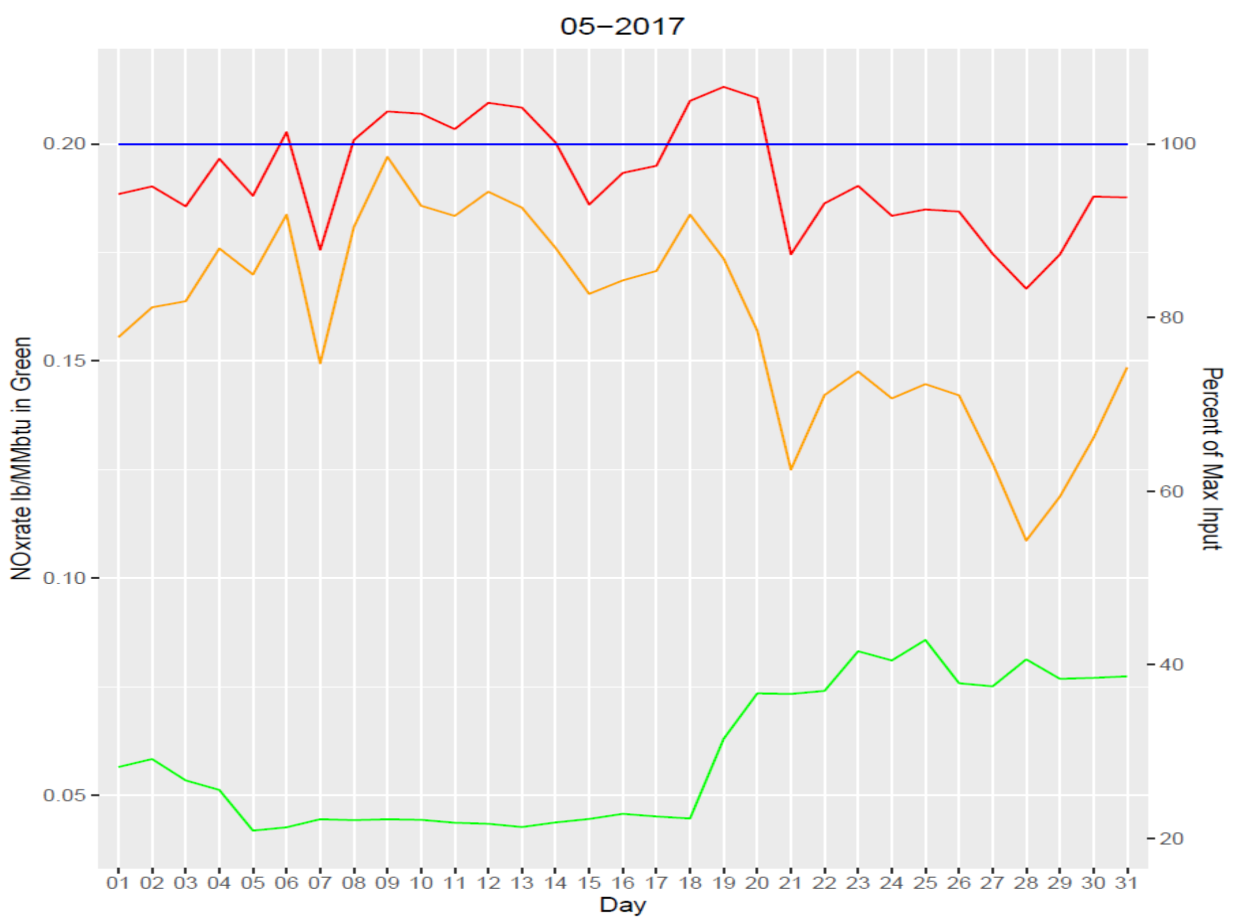
Based on a review of the ammonia feed rates, fluctuating load and NOx emission rate, any lag in the ammonia feed system is negligible. Ammonia injection rates very closely track load, and the changes in emission rate as the ammonia injection rate follows boiler load fluctuations is minor.

NOx emission limits on a daily basis:

DEP evaluated and analyzed daily NOx 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.

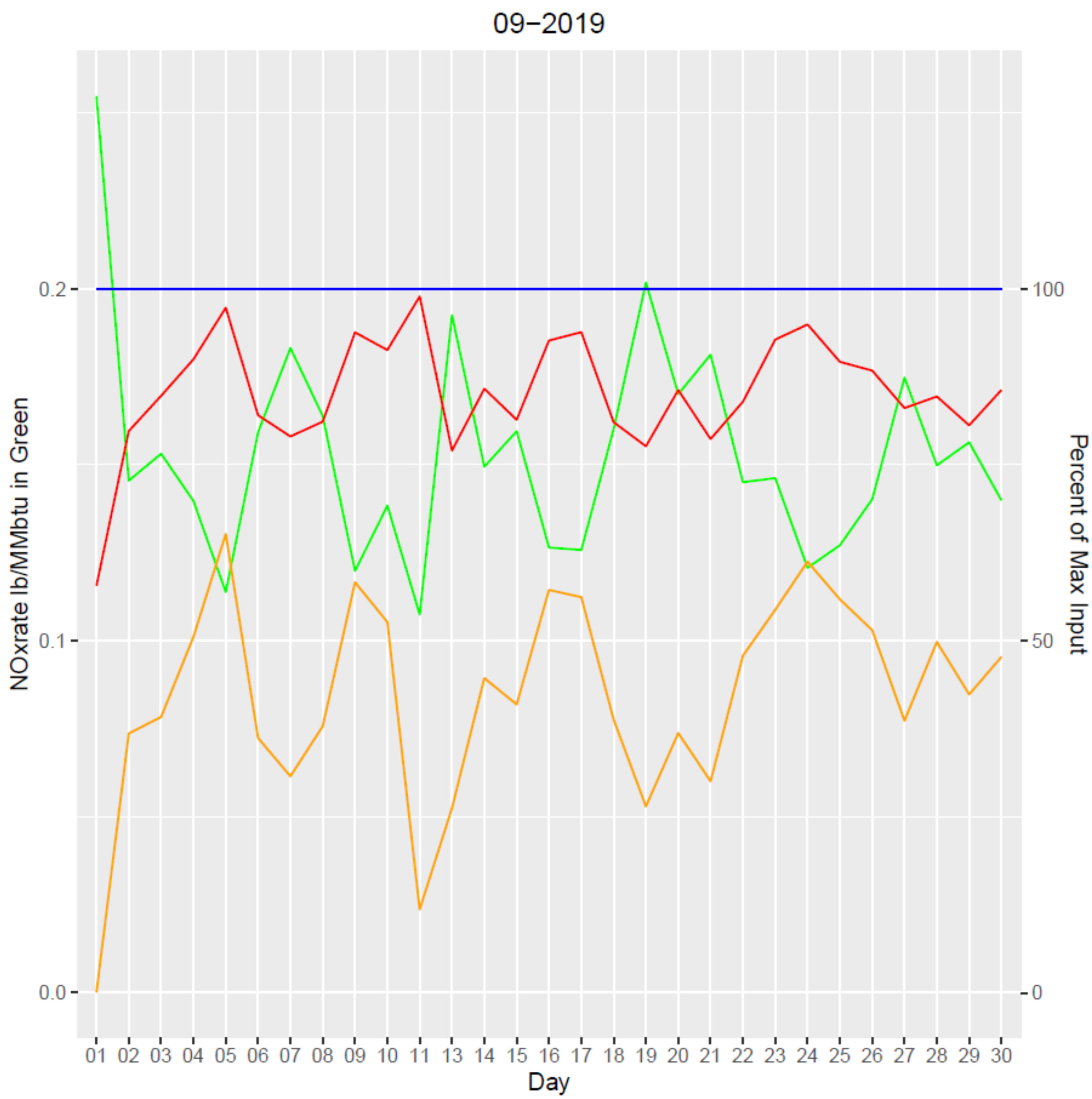
Because of the similar nature of Conemaugh's two Units, data from one unit will be considered as applicable to the other unit. Figure 1 below shows daily operating statistics for Conemaugh's Unit 1 during May of 2017. The x axis shows the day of the month while the left Y axis correlates with the green line and is in lb/MMBtu of NOx. The right Y axis is in percentage of the maximum observed input. The green line is the NOx rate of the unit for each day in lb/MMBtu. The red line is the percentage of maximum heat rate input for the unit for the day. The orange line is the percentage of max ammonia input observed. The blue line is set at 100% as a reference for the max values for the orange and red lines. As can be seen on this graph, Conemaugh was able to maintain a NOx rate of about .045 lb/MMBtu for a period of 13 consecutive days. The ammonia injection rates and heat input rates are consistently and directly correlated; an example of this is shown in Figure 1. During the period May 5 to May 18th, the ammonia injection rates and associated heat input rates have very similar curves—indicative of a ammonia injection control system operating at a set-point of 0.045 lb/MMBtu. From May 19th through the end of the month, the curves continue to correlate with each other, but the relative difference between the ammonia injection rates and heat input rates have increased. As would be expected, the NOx emission rate also increased and held a fairly steady emission rate, indicative of a set-point of 0.08 lbs/MMbtu.

Figure 1



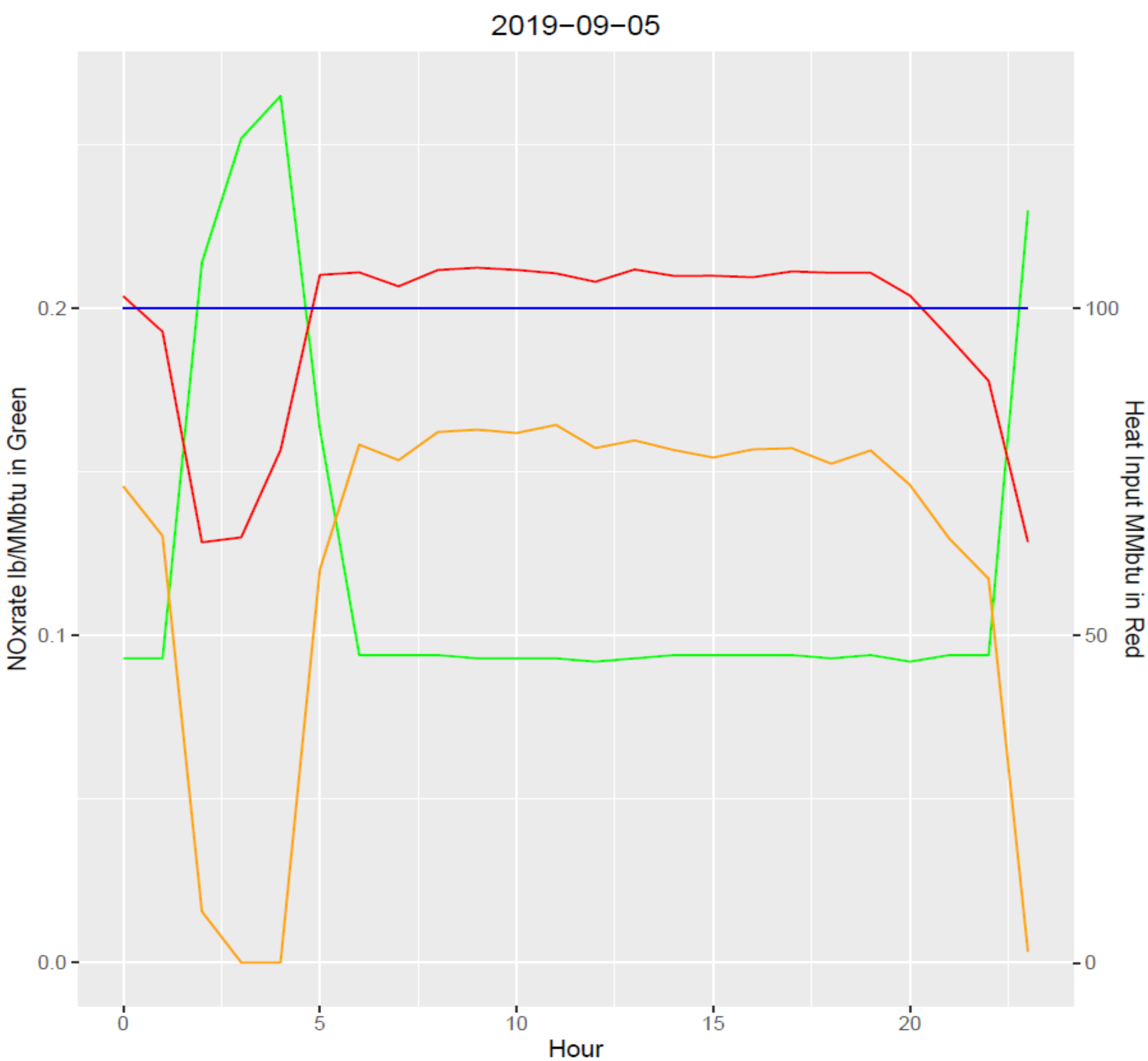
It appears that the unit was not operated with a set-point of 0.045 lb/MMBtu after May 2017 but operated with varying set-points between 0.08 and 0.065 lb /MMBtu throughout the 2017 and 2018 ozone season. This changed in 2019 during which NOx rates increased significantly overall. An example of this can be seen in Figure 2 which shows the daily emission levels for Unit 1 during September of 2019.

Figure 2



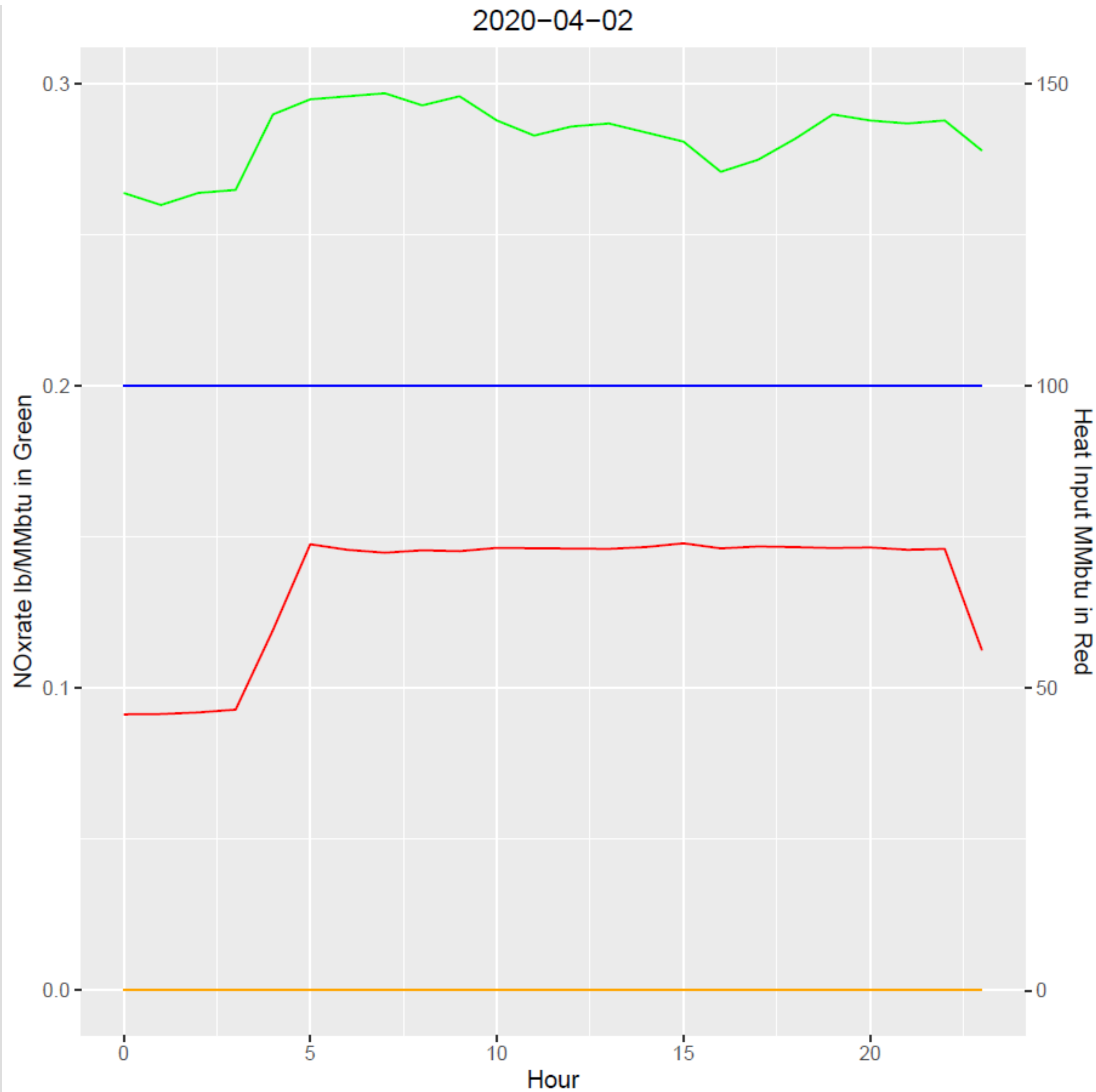
Review of the hourly data for Unit 1 during September of 2019 shows that the unit was operating at variable loads from approximately 50 to 100%, and ammonia injection ceased when the unit was operating at nearly 50% load. During periods of operation near 100% load, the NOx level is uniformly controlled to a level of almost exactly 0.1 lb/MMBtu. This strongly suggests that additional emission reductions would be achieved if the operator operated the SCR with a lower emissions setpoint while the SCR is running. Figure 3, shows Conemaugh's operations on 9/5/2019 for Unit 1. Figure 3 shows one example of Conemaugh's operators controlling NOx emission rate to a target of .1 lb/MMBtu when the SCR is on. This trend is exhibited for the entire month of September of 2019 for Unit 1. Note that the ammonia injection and heat input curves remain nearly identical, but that the difference between the two curves has further increased again.

Figure 3



Additional review of the data found examples during which the SCR was not running at operating loads that clearly support SCR operation. Figure 4 shows one such example from Unit 1 during April 2nd of 2020, prior to the start of the ozone season. The heat input remained steady at 75% for most of the month but no ammonia was injected on most days. During earlier years, 2017-2019, ammonia was consistently injected at this heat input. Simply choosing not to operate the SCR is not indicative of the control level achievable by the system.

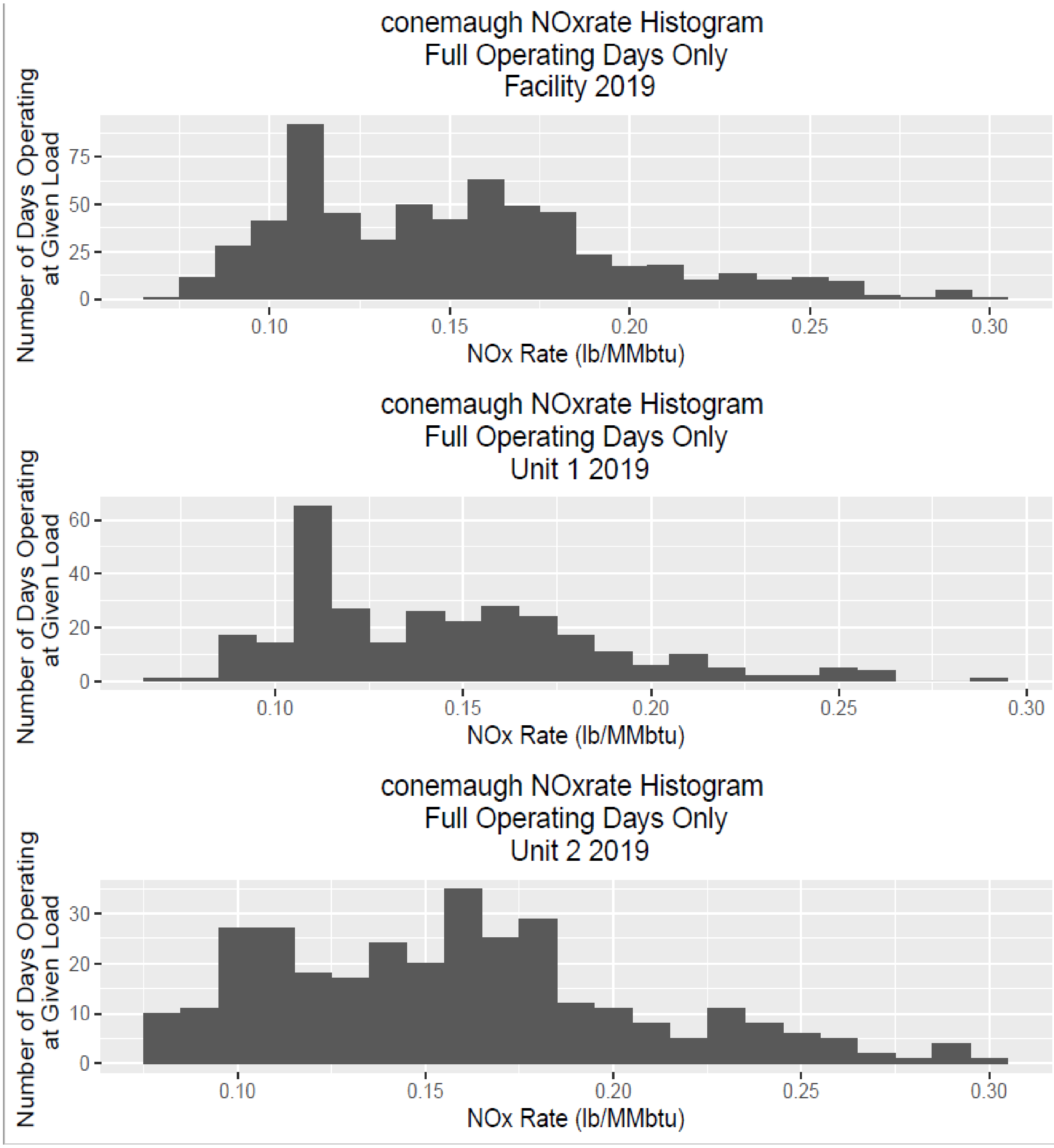
Figure 4



Based on the data presented, DEP recommends a permit limit on the NOx emission rate of 0.070 lb/MMBtu on a daily average basis with operation of SCR for both units. 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 common exclusions and are included in other state's presumptive RACT regulations. For example, Maryland's regulations for coal-fired electric generating units includes nearly identical provisions, with the exception that the Maryland regulations include an explicit exclusion for low-load operations. [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 NOx emission rate includes a factor to provide an appropriate compliance margin, fluctuations in load, any lag in the control system as well as to account for other factors in the facility's projected future operation.

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

Figure 5



As can be seen from Figure 5, in 2017, Unit 1 achieved a NOx emission rate from 0.05 lb/MMBtu to as high as 0.30 lb/MMBtu on a daily average under all operating conditions with existing LNB and SCR system. DEP believes that given Conemaugh'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 Conemaugh 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.

Conemaugh's evaluation of an LNB upgrade found it to be economically infeasible with a cost-effectiveness of $12,998 tons of NOx removed for Unit 1 and $8,345 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 6-2: Low-NOx Burner Replacement/Tuning Capital Cost Estimate – Per Boiler

Cost Item	Computation Method	Factor	Cost	Notes
Direct Costs				
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	--	$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

Cost Item	Computation Method	Factor	Cost	Notes
				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	
Installation Costs, Indirect				
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.
Modeling and Optimization Studies	Conemaugh Station Estimate	--	$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 6-3: Low-NOx Burner Replacement/Tuning Annual Cost Estimate

Cost Item	Computation Method	Factor	Cost	Notes
Direct Operating Costs				
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	
Indirect Operating Costs				
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
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	1	$2,261,617	Per unit

(1) Based on information available from the Station, the firm-specific nominal interest rate for Conemaugh 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 6-4: 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	3,672	3,498	$2,261,617	$12,998
2	3,995	3,724	$2,261,617	$8,345
Average				**$10,672**

(1) See Table 6-3 for calculation of annual costs.
(2) Based on CY2019 actual annual emissions. See Table 4-1.
(3) Based on available emissions and operating data for CY2019, the LNB upgrades are expected to reduce emissions by 174 tons/year for Unit 1 and 271 tons/year for Unit 2.

As shown in **Table 6-4**, the cost of installation of per ton of NOx removed is excessive at an average of $10,600/ton of NOx removed.

DEP evaluated Conemaugh'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, 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 net lost revenue instead of gross lost revenue, which is specifically identified as the proper factor in the US EPA (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 all of the appropriate factors, including use of estimated net revenue lost. DEP used 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. Conemaugh has publicly represented 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 Conemaugh's data, proportioned over the shutdown period. In other words, this calculation assumes that Conemaugh's RGGI cost estimates are correct, although this has clearly not been established by DEP. Recalculating the costs with revised CRF, lost net revenue and removing cost for modeling and optimization, DEP found cost-effectiveness for replacement of existing LNB with an upgraded LNB at $6,350 for Unit 1 and $4,077 for Unit 2 per ton of NOx removed and therefore, 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	174
TPY saved unit 2	271
dollars per ton unit 1	**$6,350**
dollars per ton unit 2	**$4,077**

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	0.970573561
tons of CO2 75% 28 days 850 MW unit	415,794
cost of RGGI allowances	**$3,313,876**

Boiler tuning parameters adjustments:
This option involves making a number of adjustments to the boiler operating parameters that affect the generation of NOx in the boiler fire box. 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 boiler's regular inspection, preventive maintenance, tuning, practicing during shutdown and upset conditions to prevent excess emissions, inspections and testing of Over Fire Air (OFA) components, and adjusted of burner angle to minimize NOx emissions results in lowering NOx emissions by 5-15% or at an average of 10%. The changes in 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.

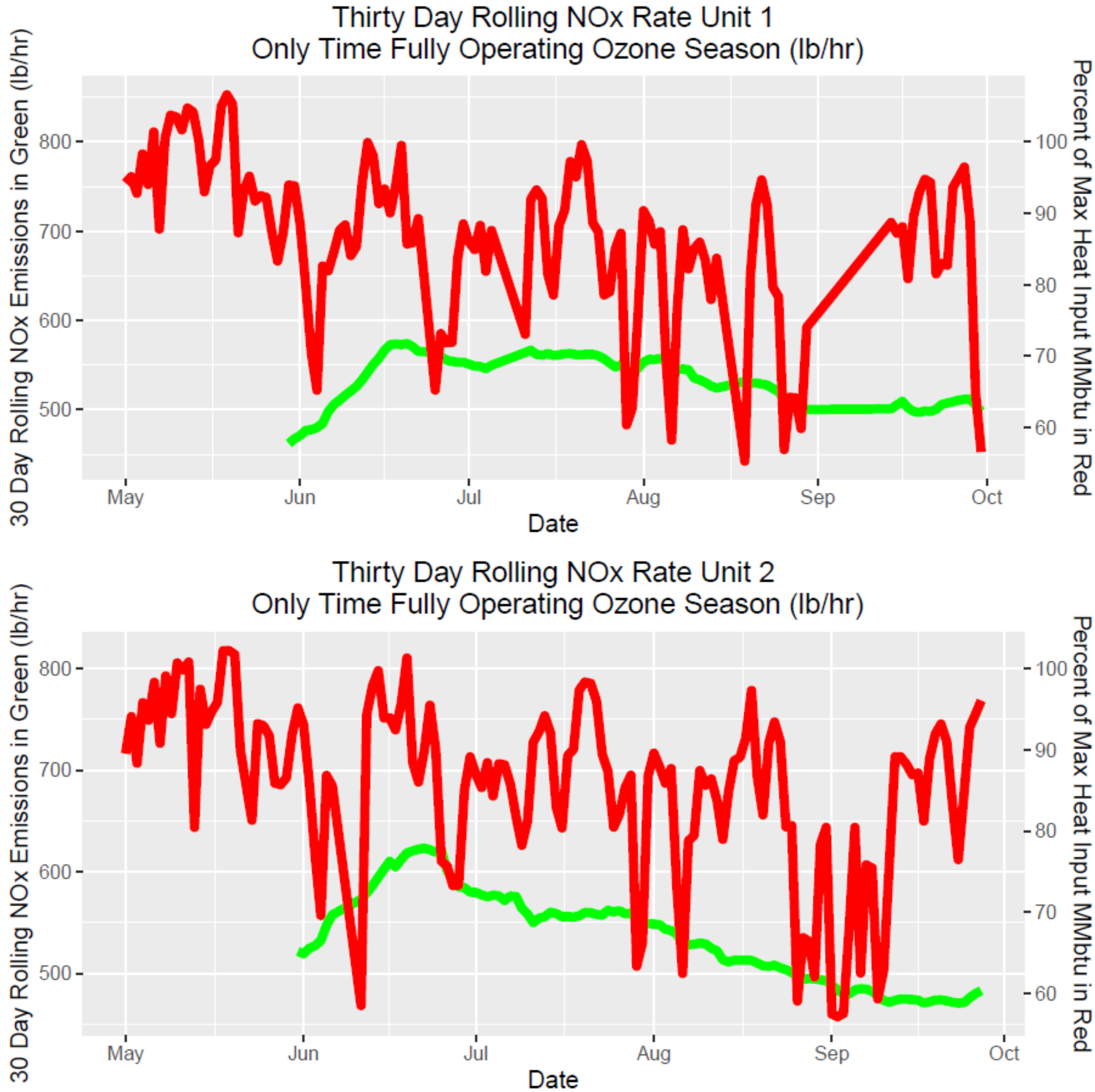
Therefore, DEP determined a NOx emission rate of 0.27 lb/MMBtu on a daily average basis at all operating conditions for both Units 1 and 2 as RACT. This value includes an appropriate compliance margin.

NOx emission limits on a 30 operational day rolling average basis:

As previously stated, the Department is proposing a daily limit of .070 lb/MMBtu based on the emission reduction potential of the SCR, including an appropriate margin for compliance. Each of Conemaugh's units emits about 580 lb NOx per hour assuming an emission level of .070 lb/MMBtu and 100% load. The impact to the environment should never exceed this level on a long-term basis. The Department is proposing a limit of 700 lb/hr limit on a 30 operational day rolling basis which accounts for all operating scenarios including situations during which the SCR is not able to operate. The compliance buffer also accounts for the fact that both units at Conemaugh operates as much as 10% over their rated capacity,

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

Figure 6



As per Figure 6, Unit 1 and 2 was operating between 55% and 100% load during ozone season in 2017, and both were able to achieve at or below 625 lbs/hr, on a 30-operating day rolling average basis, continuously. During this time both units operated at a NOx emission rate of around .075 lb NOx/MMBtu with occasional operations at higher rates, generally between .075 and .1 lb NOx/MMBtu with occasional spikes much higher. Given that the Department believes that NOx rates below .07 are readily achievable with the SCR in operation, and the fact that both units were able to achieve a 30 day rolling NOx rate of under 625 lb/hr despite operating at a rate between .075 and .1, DEP believes that Conemaugh Generating Station can achieve a NOx rate of 700 lb/hr on a 30 day rolling basis. Even if the facility were to operate at low load for a significant time during a 30 day averaging period—generating significantly more mass emissions than operation at higher loads with SCR, emission rates at high load should be significantly below 700 lb/hr allowing the facility to "make up" for higher emissions during times of low load, assuming the facility operates to the NOx rate of .045-.05 lb/MMbtu it is usually capable of meeting when the SCR is operating.

DEP determines a NOx emission rate of 700 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 NOx 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, NOx 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 NOx control. This system typically provides for 20% reduction in NOx 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 Conemaugh generating station does not have access to an adequate natural gas supply. Installing a pipeline may make this option extremely expensive. As per Conemaugh'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. DEP also notes that at least one power plant in Pennsylvania is in the process of constructing a pipeline to acquire an adequate natural gas supply to convert its coal-fired EGU equipped with SCR to natural gas operation.

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 plan to solar or wind power plant option as technically and economically infeasible. In addition, this

would constitute a change in the nature of the source which is beyond the scope of a RACT analysis.

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 NOx and is not applied to coal-fired EGU boilers because NOx emissions from coal-fired boilers are primary fuel NOx 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 NOx 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 Conemaugh 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 Conemaugh Generating Station has evaluated the possibility of bypassing the economizer during boiler's low load operation, startup, and shutdown to allow SCR operation. Conemaugh 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 is 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 Conemaugh claims that the short-term swings in the minimum electrical outputs specified by

PJM result in issues in maintaining a minimum sustainable load to full operating load. Conemaugh states that such swings in operating load result in the engaging / disengaging of the V-Temp system twice (and sometimes more times) per day, although no supporting information has been provided in the application. Conemaugh also claims that 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. No information was provided as to the periods of operation that do not have significant short terms swings in load.

PJM specifies the electrical outputs from Unit 1 and Unit 2 at Conemaugh Generating Station, which may result in both boilers operating at varying loads. DEP determines operation of V-temp system on Unit 1 and Unit 2 at Conemaugh generating station is technically infeasible during periods of short-term fluctuating loads, although it does have efficacy during certain operating periods.

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 Conemaugh 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 Conemaugh'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 Conemaugh application does not include an analysis of partial flue gas reheat using one or two 130 MMBtu/hr burners, not does it analyze other heat inputs. Clearly, any additional flue gas reheat will have a beneficial effect on NOx emission rates, and Conemaugh 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 SO_3. Dry sorbent injection before the SCR uses sodium carbonate to reduce SO_3 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 SO_3 in the flue gas stream is also desirable because it results in enhanced particulate capture by the Electrostatic Precipitator (ESP).

An SO_3 mitigation system is already installed on both units at Conemaugh Generating Station just before the flue gas desulphurization (FGD) systems to control SO_3 / $H2SO_4$ emissions from the FGDs.

Compliance demonstration, Recordkeeping, Monitoring and Reporting requirements:

The facility shall demonstrate compliance with NOx 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.

NOx RACT emission limits for Unit 1 and Unit 2:
DEP concludes that the following NOx 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 NOx mitigations measures.

(1) Emissions of NOx expressed as NO_2 for Units 1 and 2 are individually limited to a maximum of 0.070 lb NOx /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 NOx expressed as NO_2 from Unit 1 and 2 are individually limited to a maximum of 0.27 lb NOx /MMBtu on a daily average basis under all operating conditions.

(3) Emissions of NOx expressed as NO_2 from Unit 1 and 2 are individually limited to a maximum 700 lbs NOx/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. (State only requirement)

(6) The owner or operator shall maintain NOx controls as effectively as reasonably possible during startups and shutdowns.

(7) The owner or operator shall take steps to bring NOx 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.

(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 NOx reduction over combustion efficiency, including but not limited to the properly adjusted burner angle.

(12) The facility shall tune the boiler to minimize NOx emissions within 6 months of the effective date of this permit. (State only requirement)

(13) The facility shall tune the boiler to minimize NOx emissions annually after the initial boiler tuning. (State only requirement)

(14) Within 3 months of the effective date of this permit, the facility shall set the SCR at a target NOx emission rate of 0.05 lb. NOx per MMBtu. (State only requirement)

(15) After operating the SCR with an outlet NOx emission rate set-point of 0.05 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. (State only requirement)

(16) During the first 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.