COMMONWEALTH OF PENNSYLVANIA
Department of Environmental Protection
Southeast Regional Office
August 25, 2023
484.250.5920

Subject: Technical Review Memo
RACT II is RACT III Case-By-Case Analysis for Title V Operating Permit No. 09-00016
APS ID 346079, PF ID 240953
Constellation Energy Generation, LLC—Croydon Generating Station
955 River Road
Croydon, PA 19020

To: James D. Rebarchak 9/6/2023
Regional Air Quality Program Manager
Air Quality Program
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From: David S. Smith DSS 8/25/23, 9/1/2023
Engineering Specialist
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Through: Janine Tulloch-Reid, P.E. JET 8/25/2023 9/5/2023
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I. Procedural History

As part of the Reasonably Available Control Technology (RACT) regulations codified at 25 Pa. Code §§ 129.111—129.115 (relating to additional RACT requirements for major sources of NO_x and VOCs for the 2015 ozone NAAQS) (hereinafter referred to as "RACT III"), the Pennsylvania Department of Environmental Protection (DEP) has established a method under 25 Pa. Code § 129.114(i) (relating to alternative RACT proposal and petition for alternative compliance schedule) for an applicant to demonstrate that the alternative RACT compliance requirements incorporated under 25 Pa. Code § 129.99 (relating to alternative RACT proposal and petition for alternative compliance schedule) (hereinafter referred to as "RACT II") for a source that commenced operation on or before October 24, 2016, and which remain in force in the applicable operating permit continue to be RACT under RACT III as long as no modifications or changes were made to the source after October 24, 2016. The date of October 24, 2016, is the date specified in 25 Pa. Code § 129.99(i)(1) by which written RACT proposals to address the 1997 and 2008 8-hour ozone National Ambient Air Quality Standards (NAAQS) were due to DEP from the owner or operator of an air contamination source located at a major NO_x emitting facility[1] or a major VOC emitting facility[2] subject to 25 Pa. Code § 129.96(a) or (b) (relating to applicability).

The procedures to demonstrate that RACT II is RACT III are specified in 25 Pa. Code § 129.114(i)(1)(i)–(ii) and (i)(2). An applicant may submit an analysis, certified by the responsible official, that the RACT II permit

[1] As the term is defined in 25 Pa. Code § 121.1 (i.e., has a potential to emit nitrogen oxides [NO_x] of equal to or greater than 100 *tons/yr*, pursuant to subparagraph (vi)).

[2] As the term is defined in 25 Pa. Code § 121.1 (i.e., has a potential to emit volatile organic compounds (VOCs) of equal to or greater than 50 *tons/yr*, pursuant to subparagraph (v)).

requirements remain RACT for RACT III by following the procedures established in 25 Pa. Code § 129.114(i)(1)–(2).

25 Pa. Code § 129.114(i)(1) establishes cost effectiveness thresholds of $7,500 per ton of NO_x emissions reduced and $12,000 per ton of VOC emissions reduced as ''screening level values'' to determine the amount of analysis and due diligence that the applicant shall perform if there is no new pollutant specific air cleaning device, air pollution control technology or technique available at the time of submittal of the analysis.

25 Pa. Code § 129.114(i)(1)(i) specifies that the applicant that evaluates and determines that there is no new pollutant specific air cleaning device, air pollution control technology, or technique available at the time of submittal of the analysis and that each technically feasible air cleaning device, air pollution control technology, or technique evaluated for the alternative RACT requirement or RACT emission limitation approved by DEP under 25 Pa. Code § 129.99(e) had a cost effectiveness equal to or greater than $7,500 per ton of NO_x emissions reduced or $12,000 per ton of VOC emissions reduced shall include the following information in the analysis:

- A statement that explains how the owner or operator determined that there is no new pollutant specific air cleaning device, air pollution control technology, or technique available.
- A list of the technically feasible air cleaning devices, air pollution control technologies, or techniques previously evaluated under RACT II.
- A summary of the economic feasibility analysis performed for each technically feasible air cleaning device, air pollution control technology, or technique in the previous bullet and the cost effectiveness of each technically feasible air cleaning device, air pollution control technology, or technique as submitted previously under RACT II.
- A statement that an evaluation of each economic feasibility analysis summarized in the previous bullet demonstrates that the cost effectiveness remains equal to or greater than $7,500 per ton of NO_x emissions reduced or $12,000 per ton of VOC emissions reduced.

25 Pa. Code § 129.114(i)(1)(ii) specifies that the applicant that evaluates and determines that there is no new pollutant specific air cleaning device, air pollution control technology, or technique available at the time of submittal of the analysis and that each technically feasible air cleaning device, air pollution control technology, or technique evaluated for the alternative RACT requirement or RACT emission limitation approved by DEP under 25 Pa. Code § 129.99(e) had a cost effectiveness less than $7,500 per ton of NO_x emissions reduced or $12,000 per ton of VOC emissions reduced shall include the following information in the analysis:

- A statement that explains how the owner or operator determined that there is no new pollutant specific air cleaning device, air pollution control technology, or technique available.
- A list of the technically feasible air cleaning devices, air pollution control technologies, or techniques previously evaluated under RACT II.
- A summary of the economic feasibility analysis performed for each technically feasible air cleaning device, air pollution control technology, or technique in the previous bullet and the cost effectiveness of each technically feasible air cleaning device, air pollution control technology, or technique as submitted previously under RACT II.
- A statement that an evaluation of each economic feasibility analysis summarized in the previous bullet demonstrates that the cost effectiveness remains less than $7,500 per ton of NO_x emissions reduced or $12,000 per ton of VOC emissions reduced.
- A new economic feasibility analysis for each technically feasible air cleaning device, air pollution control technology, or technique.

25 Pa. Code § 129.114(i)(2) establishes the procedures that the applicant that evaluates and determines that there is a new or upgraded pollutant specific air cleaning device, air pollution control technology, or technique available at the time of submittal of the analysis shall follow.

- Perform a technical feasibility analysis and an economic feasibility analysis in accordance with 25 Pa. Code § 129.92(b) (relating to RACT proposal requirements).
- Submit that analysis to DEP for review and approval.

The applicant shall also provide additional information requested by DEP that may be necessary for the evaluation of the analysis submitted under 25 Pa. Code § 129.114(i).

II. Facility Details

Constellation Energy Generation, LLC (Constellation), operates and maintains eight no. 2 fuel oil- and/or kerosene-fired simple cycle combustion turbines, model/class nos. MS7001B/7B, manufactured by General Electric Co., at its Croydon Generating Station facility, which is located in Bristol Township, Bucks County (hereinafter referred to as "the facility"). The combustion turbines were each commissioned in 1974, are each nominally rated at 64 *MW* power output, and are used by Constellation to generate electrical power, primarily during peak demand periods, for its electrical power distribution system.

The facility is a major NO_x emitting facility[3] and is permitted under Title V Operating Permit (TVOP) No. 09-00016. On April 11, 2018, DEP issued a significant modification to the TVOP to establish alternative RACT II requirements and emission restrictions for the combustion turbines, the only sources at the facility, pursuant to 25 Pa. Code § 129.99 (see the associated DEP technical review memo, dated March 28, 2018 [*Attachment #1*]).

On **January 24, 2022**, the United States Environmental Protection Agency (EPA) approved DEP's RACT II determination for Exelon Generation Co., LLC,[4] for the combustion turbines/facility as a revision to the Commonwealth of Pennsylvania's State Implementation Plan. This approval is listed in the *Federal Register* at **87 FR 3442**, which can be accessed along with all EPA-approved RACT requirements for the Commonwealth of Pennsylvania, via the following link: https://www.epa.gov/sips-pa/epa-approved-pennsylvania-source-specific-requirements.

As the facility is a major NO_x emitting facility that commenced operation on or before August 3, 2018, pursuant to 25 Pa. Code § 129.111(a), Constellation is subject to the RACT III requirements of 25 Pa. Code §§ 129.111–129.115. In accordance with 25 Pa. Code §§ 129.111(a)(1) and 129.115(a)(1)(i), (a)(2)(i), and (a)(5)(i)–(iii), on **December 28, 2022**, Constellation submitted a notification to DEP with a listing of the sources at the facility (i.e.,the combustion turbines), a summary of the applicable RACT III requirements and emission restrictions, and its proposal for how it intends to comply with these (hereinafter referred to as "the RACT III proposal").

As the combustion turbines have previously met alternative RACT II requirements and emission restrictions and have not been modified or changed since October 24, 2016, the due date for the RACT II proposal, Constellation has included in the RACT III proposal a limited alternative RACT III analysis, in accordance with 25 Pa. Code

[3] Accordingly, the facility is also a major facility, as the term is defined in 25 Pa. Code § 121.1 (i.e., has a potential to emit NO_x of equal to or greater than 25 *tons/yr*, pursuant to subparagraph (v)).

[4] On February 1, 2022, Exelon Corporation spun off its generation business unit, including Exelon Generation Co., LLC, into a separate, independent company named Constellation Energy Corporation, with the new owner of the facility being the subsidiary Constellation.

§ 129.114(i), as follows, to demonstrate that RACT II is RACT III (see *Limited Alternative RACT III Analysis* section, below, for further discussion):

Source ID	Source Name	RACT III Provisions
031	Simple Cycle Turbine #11	25 Pa. Code § 129.114(i)(1)(i)–(ii)
032	Simple Cycle Turbine #12	25 Pa. Code § 129.114(i)(1)(i)–(ii)
033	Simple Cycle Turbine #21	25 Pa. Code § 129.114(i)(1)(i)–(ii)
034	Simple Cycle Turbine #22	25 Pa. Code § 129.114(i)(1)(i)–(ii)
035	Simple Cycle Turbine #31	25 Pa. Code § 129.114(i)(1)(i)–(ii)
036A	Simple Cycle Turbine #32	25 Pa. Code § 129.114(i)(1)(i)–(ii)
037	Simple Cycle Turbine #41	25 Pa. Code § 129.114(i)(1)(i)–(ii)
038	Simple Cycle Turbine #42	25 Pa. Code § 129.114(i)(1)(i)–(ii)

III. Limited Alternative RACT III Analysis

In the limited alternative RACT III analysis, Constellation has stated the following:

- "Available combustion turbine control technologies are common and widely known."
- "The technology screening [in the RACT II proposal] was based on unit specific information obtained from the manufacturer, General Electric, and site engineers at Croydon."
- "No new [air pollution] control technologies have been developed since the RACT II [proposal] was completed."

While Constellation did not specify any resources checked since the time of the RACT II proposal to justify how it determined that "there is no new pollutant specific air cleaning device, air pollution control technology or technique available" for the combustion turbines, pursuant to 25 Pa. Code § 129.114(i)(1)(i)(A) and (i)(1)(ii)(A), DEP has found that the air pollution control technologies evaluated in the RACT II proposal align with those indicated in a January 2022 memo on available NO_x air pollution control technologies for natural gas-fired combustion turbines from EPA's website (see *Attachment #2*). Moreover, DEP's search of EPA's RACT/BACT/LAER Clearinghouse (RBLC) did not indicate any other air cleaning devices, air pollution control technologies, or techniques. Therefore, DEP concurs that no new pollutant-specific air cleaning device, air pollution control technology, or technique is available for the combustion turbines.

In accordance with 25 Pa. Code § 129.114(i)(1), Constellation has compared the cost effectiveness of each NO_x air pollution control technology previously evaluated in the RACT II proposal and identified as technically feasible with the cost effectiveness screening level value of $7,500 per ton of NO_x emissions reduced, as follows:

Item	Water Injection	Selective Catalytic Reduction
Total Direct Costs	$20,939,406	$39,844,560
Total Indirect Installation Costs	$7,555,166	$17,131,777
TOTAL INSTALLED COST	$28,494,572	$56,976,337
Total Utilities Cost	$931,820	$3,665,483
Additional Operation and Maintenance Cost	$262,667	$178,434
Fuel Penalty	$2,663,977	$1,450,894
TOTAL DIRECT COSTS	$3,858,464	$5,294,811
Additional Total Direct and Indirect Annual Costs	$8,360,296	$9,673,152
Capital Recovery Cost	$3,346,962	$6,692,419
TOTAL ANNUAL COSTS	$11,707,258	$16,365,571
NO_x Emissions Reduction (*tons/yr*):	1,918.42	1,918.42
Cost Effectiveness (*$/ton*):	$6,102.55	$8,530.75

As the cost effectiveness calculated for water injection in the RACT II proposal is less than the cost effectiveness screening level value, Constellation has performed a new economic feasibility analysis for water injection pursuant to 25 Pa. Code § 129.114(i)(1)(ii)(E) (see *Attachment #3*), the results of which are summarized in the below table:

Item	**Water Injection**
Total Direct Costs	$27,784,662
Total Indirect Installation Costs	$10,021,740
TOTAL INSTALLED COST	$37,806,402
Total Utilities Cost	$931,820
Additional Operation and Maintenance Cost	$262,667
Fuel Penalty	$5,327,955
TOTAL DIRECT COSTS	$6,522,442
Additional Total Direct and Indirect Annual Costs	$13,337,396
Capital Recovery Cost	$4,440,726
TOTAL ANNUAL COSTS	$17,778,122
NO_x Emissions Reduction (*tons/yr*):	1,918.42
Cost Effectiveness (*$/ton*):	$9,267.06

As the updated cost effectiveness calculated for water injection is greater than the cost effectiveness screening level value, water injection remains economically infeasible.

As the cost effectiveness calculated for selective catalytic reduction (SCR) in the RACT II proposal is greater than the cost effectiveness screening level value, Constellation is not required to perform a new economic feasibility analysis for SCR, and SCR likewise remains economically infeasible.

In accordance with 25 Pa. Code § 129.115(f), and as already required in Condition # 008, Section D (under Source IDs 031–035, 036A, and 037–038), of the previously-modified (i.e., current) TVOP, Constellation shall maintain records of all information necessary to determine compliance with all applicable requirements of 25 Pa. Code §§ 129.111 and 129.114.

Therefore, compliance with the alternative RACT II requirements and emission restrictions indicated in the TVOP assures compliance with the applicable alternative RACT III requirements and emission restrictions, and there are no changes to the TVOP conditions.

IV. Public Discussion

Since December 28, 2022, the date that Constellation submitted the RACT III proposal, DEP has not had any discussions with Constellation, EPA, or the public regarding the submittal.

V. Conclusion

DEP has analyzed Constellation's proposal for considering RACT II requirements as RACT III. As part of this, DEP has reviewed the source information and cost analyses from both the RACT II and RACT III proposals and has performed an independent analysis, as discussed in the *Limited Alternative RACT III Analysis*, above, and including the continuous review of permit applications since the applicability date of RACT II, to determine that no new pollutant-specific air cleaning device, air pollution control technology, or technique is available for the combustion turbines. Based on this review, DEP has determined that the RACT II requirements satisfy the RACT III requirements. The RACT III requirements are identical to the RACT II requirements and are as stringent as RACT II.

COMMONWEALTH OF PENNSYLVANIA
Department of Environmental Protection
March 28, 2018
610-832-6242

SUBJECT: Title V Operating Permit Review Memo (Significant Modification- RACT II)
Exelon Generation Co./ Croydon
Bristol Township
Bucks County
Application No. 09-00016
APS ID No. 346079, AUTH ID No. 1156441

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Air Quality

JAB
3/30/2018

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Introduction/Facility Description

On October 24, 2016, the Pennsylvania Department of Environmental Protection (PA DEP) received an application for a significant modification to a Title V operating permit from Exelon Generation Company/Croydon Generating station ("facility" or "company") located in Bristol Township, Bucks County. The significant modification application was submitted to incorporate the requirements of the newly promulgated *Reasonably Available Control Technology*, Phase II (RACT II) regulations into the operating permit. The application was submitted with a check for $750.00 and the proof of notifications to the municipalities, as required. The Croydon Station, located at 955 River Road in Bristol Township, Bucks County, Pennsylvania, consists of eight (8) distillate oil-fired General

Electric Frame 7B combustion turbine-generator units nominally rated at 64 MW each and were commissioned in 1974.

RACT II Evaluation

Under the Federal Clean Air Act (CAA), Reasonably Available Control Technology (RACT) requirements must be re-evaluated when the United States Environmental Protection Agency revises a National Ambient Air Quality Standard (NAAQS). In order to implement the RACT requirements for the 1997 and 2008 8-hour ozone NAAQS, the Pennsylvania Environmental Quality Board (EQB) published a final-form rule on April 23, 2016 for additional RACT requirements for major sources of nitrogen oxides (NOx) and/or volatile organic compounds (VOCs), known as RACT II. Affected facilities are required to demonstrate compliance with the RACT II requirements by January 1, 2017. Facilities may demonstrate compliance with RACT II through one of three options including meeting presumptive RACT requirements and/or emission limitations, utilizing facility or system wide NOx averaging or proposing an alternative RACT requirement or emission limitation with a case-by-case RACT evaluation. The alternative RACT proposal must be submitted to the Pennsylvania Department of Environmental Protection (PADEP) by October 24, 2016. The Croydon Station is a major source of NOx and is therefore required to demonstrate compliance with the RACT II requirements. This case-by-case NOx evaluation has been developed to meet the alternative RACT proposal petition process allowed under the RACT II requirements.

The combustion turbines located at the Croydon Station do not meet the presumptive RACT requirements or emission limits promulgated in RACT II. Exelon performed a case-by-case NOx RACT evaluation by first identifying available NOx control technologies for the combustion turbines at the Croydon Station, then performed a technology screening to evaluate the technical feasibility of applying the identified controls to these units. For those controls that were determined to be technologically feasible, a cost evaluation was performed to determine which controls were cost effective. The RACT evaluation showed that no control technologies are cost effective for the combustion turbines at the Croydon Station. Because no control technologies are cost effective, Exelon is proposing an alternative RACT emission limit and is submitting the following RACT proposal in accordance with 25 Pennsylvania Code §129.92 (RACT proposal requirements). Exelon is proposing to keep the present limitations on each combustion turbine as an alternative.

Emission Source Summary

The station consists of eight (8) distillate oil-fired General Electric Frame 7B combustion turbine-generator units nominally rated at 64 MW each and were commissioned in 1974. The units are operated in accordance with Title V Operating Permit 09-00016 issued on November 18, 2013. The following table lists the combustion turbines at the facility:

Source ID	Source name	# 2 Fuel Oil Throughput
31	Simple Cycle Turbine # 11	5,940 Gallons/hr
32	Simple Cycle Turbine # 12	5,940 Gallons/hr
33	Simple Cycle Turbine # 21	5,940 Gallons/hr
34	Simple Cycle Turbine # 22	5,940 Gallons/hr
35	Simple Cycle Turbine # 31	5,940 Gallons/hr
36	Simple Cycle Turbine # 32	5,940 Gallons/hr
37	Simple Cycle Turbine # 41	5,940 Gallons/hr
38	Simple Cycle Turbine # 42	5,940 Gallons/hr

The case-by-case NOx RACT evaluation includes, (1) An identification of available NOx control technologies for the combustion turbines at the Croydon Station and (2) A technology screening to evaluate the technical feasibility of applying the identified controls to these units. For those controls that were determined to be technologically feasible, a cost evaluation was performed to determine which controls were economically feasible as defined by the conditions of RACT II.

The operating permit also includes the following limits:

Facility-Wide NOx (Tons/yr)	1,296
Max. NOx (per turbine) (Lbs/MMBtu)	0.7
Max. NOx (per turbine) (Lbs/hr)	587
Max. fuel throughput (per turbine) (Gallons/hr)	5,940
Capacity Factor (%) (per turbine)	20%
Max. Heat Input (MMBtu/hr) (per turbine)	838

According to RACT II, the applicable presumptive RACT NOx emissions limitations for these combustion turbines under 25 PA Code §129.97(g) is 96 ppmvd NOx at 15% oxygen for combustion turbines firing fuel oil.

NOx Control Technologies

The principal nitrogen pollutants generated by combustion turbines are nitric oxide (NO) and nitrogen dioxide (NO_2), collectively known as NOx. NOx is primarily formed by two mechanisms in the combustion turbine combustor. The first and primary mechanism is the fixation of atmospheric nitrogen during the combustion process and the resultant pollutant is referred to as thermal NOx. The second mechanism is the conversion of the fuel bound nitrogen to NOx in the presence of excess air during the combustion process. EPA has determined that here is little fuel bound NOx formation in natural gas and distillate oil fired combustion turbines and thermal NOx is the dominant mechanism in this source category. Several NOx thermal control technologies are available for combustion turbines are:

- Water injection
- Fuel switching

- Selective Catalytic Reduction (SCR)
- Dry low-NOx combustors

Water Injection

This technology is based on the injection of demineralized water into the combustion zone. This has the effect of lowering the peak flame temperature, thus reducing the level of production of thermal NOx. After admission to the combustor, the water both dilutes the combustion product stream and vaporizes while absorbing the heat of vaporization. This action lowers the peak combustion temperature. The additional mass flow rate through the combustion turbine due to water injection increases the output of the unit and decreases its efficiency. Water injection may also affect the internals of the turbine requiring more frequent maintenance. Water injection is commonly used for NOx reduction and power augmentation on combustion turbines and it is considered a proven technology. This control technology is considered technically feasible for the RACT affected units. Water injection can typically reduce NOx emissions from combustion turbines by about 60-75% from the uncontrolled condition. The maximum reduction level depends on the combustion turbine design.

Fuel Switching

This method reduces the production of NOx by switching to a fuel which produces less NOx. In the case of switching from oil to natural gas fuel, there is a significant impact on the production of thermal NOx since the flame temperature of natural gas is about 100 degrees lower than that of distillate fuel. In cases where a natural gas supply line is in close proximity to a plant, switching from distillate oil to natural gas is a feasible method of NOx control. In most cases, however, where natural gas in not immediately available, the cost of bringing the fuel to the plant makes the fuel-switch option cost prohibitive. There are no natural gas pipelines near the Croydon Station. Switching to natural gas will require laying of a large natural gas pipeline infrastructure and access at the site. This option will require detailed environmental assessment of the impacts of the pipeline on the surrounding media, industrial and residential area surrounding the facility. This option will be also extremely expensive. This technology is therefore considered not technically feasible for the RACT affected units.

Selective Catalytic Reduction (SCR)

Selective Catalytic Reduction (SCR) removes NOx from the gas at the exhaust of the combustion turbine. The SCR system comprises various components, with the central component being the reactor containing the catalyst. This catalyst is typically an active phase of vanadium pentoxide on a carrier of titanium dioxide, formed into elements of a parallel flow configuration. A honeycomb-shaped substrate is the common shape of catalyst elements. The normal operating temperature for the catalytic process is typically 550°F to 900°F. The minimum operating temperature is plant-specific and depends on flue gas conditions. Turbine exhaust that exceeds the maximum catalyst operating temperature must be cooled to within the catalyst reaction temperatures range and to prevent catalyst damage due to excessive heat. Tempering air fans that draw ambient air into the exhaust steam prior to the catalyst are used to control maximum temperatures but increase the system complexity, cost and the amount of exhaust that requires treatment. The SCR process uses ammonia as the reducing agent to convert the NOx to nitrogen (N_2) and water vapor at the catalyst surface. Ammonia vapor is introduced into the flue gas duct via an ammonia injection grid (AIG) ahead of the SCR reactor and catalyst. The ammonia & the catalyst cause the NOx to break down into nitrogen and water, which both are harmless compounds. One mole of ammonia reacts with one mole of NOx. A minor portion of ammonia will leave the catalyst unreacted. This unreacted ammonia is referred to as ammonia slip. With the reduction of NOx, other reactions between NOx and ammonia can also take place, but to a minor extent. On the catalyst surface, the primary chemical reactions that occur are:

$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$
$NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O$

The lower SCR operating temperature is determined from the composition of the flue gas with respect to SO_3, water, and NH_3. These compounds will form ammonium sulfate and ammonium bisulfate as the temperature is decreased. These salts will deposit in the catalyst pores and cause it to deactivate. The operating temperature is chosen to minimize this condensation. Several side reactions may occur under certain conditions, but the oxidation of SO_2 to SO_3 is of most concern. This reaction is usually minimized by optimal catalyst design. The oxidation rate increases as the flue gas temperature increases, another flue gas temperature driver. SCR is considered a technically feasible control technology for these units.

Dry Low NOx Combustors

Dry low NOx combustors utilize a staged combustion process to minimize residence time in the high temperature portion of the flame. They are also designed for very lean fuel-air mixtures, such that there is more oxygen available than there is fuel which results in a lower flame temperature. General Electric has not yet developed a dry low NOx burner retrofit for firing distillate oil for this model combustion turbine firing distillate oil. When firing distillate oil, the use of a dry low NOx burner requires the concurrent use of water injection. This control technology is therefore not technically feasible for these RACT affected units.

Based on the results of the technology screening analysis, water injection and SCR are the only technologically feasible NOx control options for the combustion turbines at the Croydon Station. These control technologies were further analyzed for cost effectiveness.

The cost estimates were based on the control technology option (i.e. water injection or SCR) being installed on each combustion turbine and controlling the NOx from a baseline level of 180 ppmv @15% O_2 (0.7 lbs/MMBTu) to presumptive RACT II level of 96 ppmv @ 15% O_2. Exelon is not proposing to use emission averaging between the units.

Cost Effectiveness ($/Ton): $ 6,103 for the Water Injection, and $ 8,531 for the SCR technology *(Based on difference in annual emissions from baseline condition of 180 ppmv @ 15% O_2 to the presumptive RACT II limit of 96 ppmv @15% O_2)* .

The presumptive RACT benchmark for cost effectiveness is $2,800/ton NOx. The RACT II preamble notes that a 25% buffer to the cost-effectiveness will not change the presumptive RACT determination. This buffer increases the presumptive RACT benchmark to $3,500/ton NOx. Based on this benchmark, the cost analysis shows that both water injection and SCR are not cost effective for the combustion turbines at the Croydon Station.

RACT Proposal

Based on the technology screening and economic analysis, there are no add-on NOx control technologies that are technologically feasible or cost effective for the combustion turbines at the Croydon Station. The baseline NOx emissions show that the units do not meet the presumptive RACT requirements or emissions limits specified in RACT II. Because the units do not meet the presumptive RACT emission limits, Exelon has prepared this case-by-case RACT proposal in accordance with the requirements of 25 Pennsylvania Code §129.92 for approval by the PADEP

Emission Restrictions

The facility will operate in accordance with a Title V Operating Permit that restricts NOx emissions to the following permit limits:

Permit Limits

Facility-Wide NOx (Tons/yr) 1,296
Max. NOx (per turbine) (Lbs/MMBtu) 0.7
Max. NOx (per turbine) (Lbs/hr) 587
Capacity Factor 20%

The baseline emission rate used in the economic analysis is based on the existing permit limit 0.70 lbs/MMBtu, which is 180 ppmvd@15% O_2 using stack conditions. Because the RACT evaluation showed that there were no cost-effective control technologies for the combustion turbines at the Croydon Station, Exelon proposes to keep the 0.70 lbs/MMBtu on a 30-day rolling average basis as the case by case RACT limit for each turbine. Exelon will also maintain the facility-wide NOx limit of 1,296 tons per year and the hourly NOx limit of 587 lbs/hr per turbine.

Testing Requirements

Exelon will demonstrate compliance with the proposed NOx RACT emission limitation with source testing in accordance with the terms and conditions of the facility's existing Title V Operating Permit. Exelon will test for the NOx emissions in lbs/MMBtu and lbs/hr in accordance with the provisions of 25 Pennsylvania Code §129 and 145. Exelon shall perform the testing on all combustion turbines at the facility within 10 % of the operation for all turbines, then if the permittee shows that the emission rates for NOx is similar for each, then permittee can complete two more runs on one turbine. Permittee shall do this within the first year, then afterward, permittee shall perform the testing on all eight turbines at least once every three permit terms. Permittee also set up annual tune-ups (every two years) for all turbines to make sure that they are being maintained properly in between testing.

Monitoring, Recordkeeping and Reporting Requirements

Exelon will continue to comply with the monitoring, recordkeeping and reporting requirements in accordance with the facility's existing Title V Operating Permit. Exelon will record monthly fuel consumption, monthly electrical power generated, the monthly and twelve month rolling annual capacity factor for each turbine and monthly NOx emissions calculated using the most recent stack test results. The facility will also maintain records of the emissions tests conducted on the turbines. NOx emissions will be reported annually in the facility's annual emissions report submitted to the PADEP.

Changes made to the permit with this permit modification

1. Section C: The Section C of the permit has been updated to show the compliance as proposed with the facility emissions limit.

The stack testing requirement for the NOx limit was changed to meet the RACT II requirements.

All other terms and requirements not mentioned above remained in the permit unchanged.

Existing conditions set under RACT I remain in effect.

Publication

1. PA Bulletin Notice: The intent to issue notice was published in the Pennsylvania Bulletin on November 12, 2016 (Vol. 46, No. 46).
2. Newspaper Notice: Intent to issue the TV permit notice was published in Bucks County Courier Times for three days starting November 17, 2016.
3. EPA: The draft permit was sent to EPA on December 9, 2016

Comments & Response

PA DEP received no comments from the Company, EPA, or Public.

Recommendation

It is recommended that the Title V operating permit (Significant Modification) (09-00016) be issued to Exelon Generation Co. located in Bristol Township, Bucks County.

TR- Exelon-09-00016

Combustion Turbine NOx Control Technology Memo

Final, Rev. 1

January 2022

Project 13527-002

Eastern Research Group, Inc.

Prepared by

Sargent & Lundy

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Attachment # 2

LEGAL NOTICE

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This work was funded by U.S. Environmental Protection Agency (EPA) through Eastern Research Group, Inc. (ERG) as a contractor and reviewed by ERG and EPA personnel.

Purpose

This report summarizes the available nitrogen oxides (NOx) control technologies available for natural gas combustion turbines, including natural gas combined cycle (NGCC) and simple cycle facilities. These technologies are generally divided into two categories: combustion controls and post-combustion controls. Combustion controls reduce the amount of NOx generated in the turbine combustion process and include water injection and dry and ultra-low NOx (ULN and DLN) systems. Post-combustion controls remove NOx from the exhaust gas and includes selective catalytic reduction (SCR).

The following sections provide a brief background of NOx emissions, description of the technologies, a summary of its applicability in various combustion turbines, a typical range of performance, and a cost summary for a sample combustion turbine facility.

NOx Background

There are two mechanisms by which NOx is formed in turbine combustors; fuel NOx and thermal NOx. Fuel NOx is formed by the reaction of nitrogen bound in the fuel with oxygen in the combustion air. Natural gas typically does not have a high nitrogen composition; thus, fuel NOx is not the dominant source of NOx in natural gas fired facilities. Thermal NOx formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form NOx. The major contributing chemical reactions occur in the high temperature area of the gas turbine combustor and NOx formation increases with spikes in temperature and residence time.

There are several compounds that NOx represents, but NO and NO_2 are the most prevalent compounds found in combustion turbine exhaust. The use of duct firing in combined cycle facilities also adds to the total amount of NOx emissions generated. The majority of emissions from combustion turbines at full load are in the form of NO, however, NO is converted to NO_2 in the atmosphere to form ozone (O_3). Additionally, the use of oxidation catalyst for carbon monoxide (CO) control can increase the NO_2 ratio, by oxidizing NO to NO_2.

Water & Steam Injection

Description

Water and steam injection have been used since the 1970's as a means of controlling NOx emission from combustion turbines. Inside the combustion turbine, fuel rich zones that create high flame temperatures are the result of the simultaneous mixing of fuel and air and their subsequent combustion. Injecting water or steam into the flame area of the combustor provides a heat sink that lowers the combustion zone temperature and reduces thermal NOx formation. As noted earlier in the report, as the combustion zone temperature decreases, NOx production decreases exponentially. Water used in this process must be of high quality (e.g. demineralized water) to prevent deposits and corrosion from occurring in the turbine. While many combined cycle facilities may have existing demineralized water treatment on site, existing simple cycle facilities often do not. In those cases, there is the option to build or rent new water treatment equipment or have high quality water delivered to site.

Water is more efficient for reducing the flame temperature than steam, as the energy required to vaporize the water creates a larger heat sink. Generally, the steam flow required is 1.5-2 times the amount of water required for given NOx reduction. Water and steam injection systems are designed to a specific "water-to-fuel ratio" (WFR) which has a direct impact on the controlled NOx emission rate and is generally controlled by the turbine inlet temperature and ambient temperature.

As combustion turbine designs are developed with higher firing temperatures to increase thermal efficiencies, higher water injection rates are required to control NOx emissions. However, points are reached where the amount of water and steam injected begins to create several design issues that must be considered. As water is injected at higher rates to further reduce NOx emissions, the thermodynamic efficiency of the combustion turbine will decrease, seen as an increase in heat rate, due to the energy required to turn the water into steam; however, depending on the overall mass flow being added, there is a potential to break even on total power generated. In addition, higher water and steam injection rates can cause an increase in the dynamic pressure activity in the combustor which can cause wear and tear within the combustion turbine. As the addition of water and steam creates thermodynamic inefficiencies in the combustion process, higher levels of carbon monoxide production are commonly seen. The rate of carbon monoxide production increases as the amount of water and steam injected increases. Overall, water and steam injection create a dichotomy due to the need for facilities to inject higher water and steam rates to meet lower NOx emission limits, exacerbating the problems associated with increased injection.

Applicability and Typical Performance

Water injection is a well-established technology and modern technology can offer NOx emissions of below 42 ppm (0.05 lb/mmbtu), with the lowest practical emissions of 25 ppm (0.03 lb/mmbtu).[1] Compared to other NOx emission control technologies, water injection may have a lower capital cost, but higher variable costs. This makes water injection especially attractive for peaking combustion turbines or other units that operate infrequently. It is most often applied to smaller frame turbines (e.g. GE LM series of aeroderivatives), rather than the modern large-frame heavy duty turbines (>200 MW) that have been installed since 2010; generally water injection has been superseded by other technology for combustion based NOx control on heavy-duty turbines (see DLN section). The high variable cost is partly due to the quality of water that is required for injection, which not every plant has excess capacity to meet, especially simple cycle facilities, thus facilities with water limitations would not be well suited for water injection. While there may be scenarios where water and steam injection would be more attractive than other control technologies, injection can be added to both new combined cycle and simple cycle facilities, as well as retrofitting existing units. This control method is one of the most historically used technologies to reduce NOx emissions. In addition, water and steam injection can be combined with post combustion control technologies such as SCR systems to further reduce NOx emissions.

Dry Low NOx (DLN) And Ultra-Low NOx (ULN) Burners

Description

DLN combustor technology premixes air and a lean fuel mixture prior to injection into the combustion turbine that significantly reduces peak flame temperature and thermal NOx formation. Conventional combustors are diffusion controlled where fuel and air are injected separately. Combustion occurs locally at stoichiometric interfaces resulting in hot spots that produce high levels of NOx. In contrast, DLN combustors generally operate in a premixed mode where air and fuel are mixed before entering the

[1] GE Power Generation, Schorr, M. M., & Chalfin, J. (1999, September). *Gas Turbine NOx Emissions Approaching Zero – Is it Worth the Price?* (GER 4172). General Electric Power Systems. https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-4172-gas-turbine-nox-emissions-approaching-zero-worth-price.pdf

combustor. The underlying principle is to supply the combustion zone with a completely homogenous, lean mixture of fuel and air. DLN combustor technology generally consists of hybrid combustion, combining diffusion flame (for low loads) plus DLN flame combustor technology (for high loads). Due to the flame instability limitations of the DLN combustor below approximately 50 percent of rated load, the turbine is typically operated in a conventional diffusion flame mode until the load reaches approximately 50 percent. As a result, NOx levels rise when operating under low load conditions. For a given turbine, the DLN combustor volume is typically twice that of a conventional combustor. ULN technology is a further development of DLN technology that uses similar combustor designs to achieve enhanced fuel/air mixing that allow for even further reduction in NOx emissions.

Applicability and Typical Performance

DLN and ULN systems are an attractive option for most combustion turbines due to the lower fuel nitrogen content in natural gas. They offer the potential for substantial reduction of NOx from turbines, as well as improved performance when compared to water injection. Depending on the frame size, these systems can achieve baseline NOx emissions of 9-15 ppm (0.01 – 0.018 lb/mmbtu) for DLN and as low as 5 ppm (0.006 lb/mmbtu) for ULN. However, the combustor design for DLN and ULN systems is typically larger than conventional types, and space may not be available in older turbines for the upgrade. DLN combustors also can be limited in wider operating ranges than conventional combustors. Gas facilities that are expected to cycle on a regular my experience spikes in NOx emissions due to the nature of how the technology performs at lower loads.

DLN / ULN capital costs vary with the size of the turbine and the specifics of the particular turbine being retrofitted. Baseline NOx level will also significantly affect the estimate of cost per ton of NOx reduced. DLN and ULN technologies are applicable to both combined cycle and simple cycle units, and are a developing technology that is being included in new facilities design to help meet ultra-low emission requirements along with being an attractive option for existing facilities that have the available space to accommodate the upgraded combustors. Similar to water and steam injection systems, DLN and ULN can be used in combination with post combustion technologies such as SCR to meet even lower emission rates at the stack.

Selective Catalytic Reduction (SCR)

Description

Selective catalytic reduction (SCR) is the most widely used treatment for a gas turbine and typically required on new installations as part of the Best Available Control Technology (BACT) evaluation results. SCR is a process in which ammonia reacts with NOx in the presence of a catalyst to reduce the NOx to nitrogen and water. The catalyst enhances the reactions between NOx and ammonia, according to the following reactions, but must be within a specific temperature window:

$$2\ NO + 2\ NH_3 + \frac{1}{2}\ O_2 \rightarrow 2\ N_2 + 3\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Note that for high NOx reduction, ammonia is typically injected at higher than a 1.0 stoichiometric ratio of ammonia-to-NOx removed; this results in ammonia slip. Systems design is therefore balanced to ensure NOx reduction is maximized while ammonia slip is minimized.

For an SCR system, multiple reagents may be used, including anhydrous ammonia, aqueous ammonia (19% and 29%), and ammonia generated from urea conversion. This process requires additional equipment to store, vaporize, dilute, and mix the reagent prior to being injected into the system through the ammonia injection grid (AIG). The SCR reactor is located downstream of the combustion turbine itself, and in the case of a combined cycle facility with a heat recovery steam generator (HRSG), it is located within the tube banks at an appropriate temperature region. The typical temperature window for this process is roughly 600-750°F. The most widely used SCR catalyst is formulated with titanium oxide (TiO_2) as a base substance and vanadium pentoxide (V_2O_5) as the active component. Other compounds, such as tungsten oxide and silicon oxide, are added for strength or thermal resistance. Unlike with coal-fired applications, the catalyst used is typically stacked vertically with gas flow horizontally through the catalyst face, has a much smaller pitch due to the limited particulate and plugging concerns, and does not deactivate as rapidly due to minimal catalyst poisons in the flue gas.

Applicability and Typical Performance

SCR systems are used throughout the power industry as a NOx control technology and developments in catalyst technologies have allowed for broader implementation of the process. Almost all new combustion turbine facilities, whether simple cycle or combined cycle, require an SCR system in conjunction with a combustion technology (DLN or water/steam injection) in order to meet stringent NOx emission rates. Based on data from the Clean Air Market Database (CAMD), 80% of combined cycle facilities implement an SCR system compared to 10% of simple cycle units. A combination of SCR with combustion control technologies can achieve levels as low as 2 ppm (0.002 lb/mmtbu) of NOx with 2-5 ppm of ammonia slip, which is currently considered Lowest Available Emission Rate (LAER) for combined cycle units.

Typically, SCR systems are installed in combined cycle applications downstream of the high-pressure steam tubes section due to temperature impacts on the reaction process. However, developments in low and high temperature SCR systems have made installations of SCR systems more widely possible. High temperature catalyst (>800°F), which includes more precious metal composition, can be used on simple cycle systems downstream of the turbine; however, in most applications, a reactor is built with tempering air to utilize typical catalyst temperature composition.

Existing combined cycle facilities with SCR units in place that are looking to further reduce NOx emissions need to understand available space inside their reactor for extra catalyst volume or activity. For combined cycle facilities originally built without SCR, if extra space in the HRSG was not dedicated for the future AIG and catalyst, it may be impossible to retrofit the facility with SCR. Simple cycles units looking to add an SCR unit would see high costs as well due to either the use of a high temperature system that can be placed immediately downstream of the combustion turbine, or a larger SCR reactor that would require tempering air. Either way, duct or stack expansion is required to make an appropriate reactor with decreased flue gas velocity through the catalyst.

As noted above, temperatures of the flue gas and in the SCR play a major role in performance. Temperature requirements dictate the location of where an SCR system is placed within the duct path in order to maintain efficiency of the reactions. Facilities that expect to operate at or near full load will have constant temperatures along the flue gas path, however, cycling units will experience large temperature swings of the flue gas decreasing the reaction kinetics inside the SCR. Below the catalyst design temperature window (typically around 50-60% load), ammonia injection must cease, which may alter the facility’s ability to meet NOx emissions rate at low load. As such, the SCR system design temperature typically dictates the minimum emission compliance load.

Other impacts to the existing facility operation with retrofitting an SCR would be impact to the overall turbine backpressure. Adding a new catalyst bed can add around 4 in.w.c. of pressure drop to the system, causing backpressure to the combustion turbine. This results in a nominal increase to the performance and heat rate of the turbine.

Combustion Turbine Emission Control Summary

The following table provides a qualitative summary of the technologies described in the above sections when reviewing its applicability towards new and existing facilities.

Table 1 – Control Technology Considerations

Control Technology	New Facilities	Existing Facilities (Retrofit)
Water / Steam Injection	- Common system installed historically on small frame turbines. - Requires high quality water for injection. Facility must have available water treatment system. - Due to higher operating costs / lower capital, attractive option for peaking or cycling operation. - Can be used in conjunction with SCR.	- Can be retrofitted to majority of existing facilities (combined or simple cycle). - Similar water considerations. - Similar operational considerations.
Dry / Ultra Low NO_x	- Common system installed in new facilities. - Can be used in conjunction with SCR.	- Can be retrofitted to majority of existing facilities, however, turbine must have available space for new combustors as they are larger than conventional type.
Selective Catalytic Reduction	- Common system installed in new facilities, especially in HRSGs. - Can be used in conjunction with Water/Steam Injection or DLN / ULN systems to achieve BACT or LAER limits.	- Hard to retrofit on NGCC if extra HRSG space was not provided initially. - Requires separate reactor for simple cycle applications that are very costly.

Sample Unit Cost Estimate Summary

To further evaluate the NOx reduction technologies described in the above sections, order of magnitude costs were developed for two potential configurations: a sample simple cycle peaker SCR retrofit and a sample NGCC SCR retrofit. The following section provides a cost summary of the technologies when retrofitting an SCR system outlined in Table 2 below. Project costs account for direct costs of a complete NO_x control system along with general conditions, and project indirect costs. The cost estimate is based largely on Sargent & Lundy LLC experience on similar projects. Detailed engineering has not been performed, and specific site characteristics other than those listed in Table 2 were not taken into consideration. The estimate includes but is not limited to the following scope;

- Direct Costs
    - Material / Equipment and Labor
        - Civil / Structural / Architectural
        - Mechanical Equipment, Piping, Valves, Insulation

        - Electrical equipment
        - Instrumentation and controls
- General Conditions
    - Additional labor costs, site overhead and other construction indirects
- Indirect Costs
    - Engineering, construction management support, startup/commissioning, contingency.

Operating and maintenance (O&M) costs are also provided in Table 3. Costs are based on fixed costs associated with labor and variable costs associated with utilities, water, reagents, and catalysts as required for operation of the specific control system on an annual basis along with any performance impacts to the plant output. The capacity factor of the facility is accounted for in the order of magnitude cost.

Table 2 – Sample Unit Information

Parameter	Units	Example 1	Example 2
Facility Type		Simple Cycle Combustion Turbine	Natural Gas Combined Cycle
Output	MW	50 MW Turbine	90 MW Turbine
NOx Emissions	lb/mmbtu	0.15	0.05
	ppmvd @ 15% O_2	~40	~13
Capacity Factor	%	15 (during ozone season)	65
Existing NOx Control		Water Injection	Steam Injection

Table 3 – Example 1 Order of Magnitude Cost Summary

Reference Case[1]	Control Technology	Project Cost[2]	Annual O&M Cost[3]
Example 1	SCR System	$16,000,000	$70,000
	DLN / ULN	$2,500,000	$60,000
	Water Injection	$5,000,000	$100,000
Example 2	SCR System	$6,200,000	$300,000

Notes:

1 – Costs based on a retrofit of the sample unit described in Table 2.

2 – Project Costs are overnight total project costs, including all project indirects. All costs are provided in 2021 dollars, reference project cost information used as the basis was adjusted to 2021 dollars using on an escalation factor of 2.5% based on the industry trends over the last ten years (2010 – 2020) excluding the current market conditions.

3 – O&M costs consider loss of power sales due to additional turbine back pressure along with aux power consumption, reagent, and catalyst costs.

As shown in Table 3 above, an SCR system is expected to have the highest project cost of the three evaluated technologies for simple cycle, with the DLN and Water Injection system capital costs being much lower. Cost for the simple cycle SCR factors in a new stack, reactor casing, tempering air system, and a reagent injection system, accounting for large capital items that are not necessary for DLN and water injection. The cost for a NGCC SCR is much smaller, due to only including catalyst, AIG, and an ammonia system; it is assumed that there is already additional space reserved within the HRSG for the catalyst and AIG itself and that the flue gas velocity and temperatures are already appropriate for SCR operation.

Table 4 below summarizes additional considerations when evaluating the capital and operating costs of NO_x reduction technologies that may have a large impact on the overall project.

Table 4 - Capital and Operating Cost Considerations

Control Technology	Capital Cost	Operating and Maintenance Cost
Water / Steam Injection	May require an upgrade to the water treatment system. Cost can increase if a new water treatment system is required.	Requires high quality water for injection and continued inspection and maintenance.
Dry / Ultra Low NO_x	New combustors that must replace existing conventional type. More expensive than conventional combustors.	General maintenance similar to conventional combustors.
Selective Catalytic Reduction	Moderate incremental cost for including in initial NGCC HRSG design. High cost for simple cycle systems to provide a separate reactor.	Reagent supply, catalyst replacement, and general maintenance. Catalyst and reactor pressure drop can decrease turbine output.

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Table C-2: Basis for Calculations

Parameter	Value	Units	Reference/Basis
Unit Description:			
Unit Type	GE Frame 7B Simple Cycle		
Number of units	8		
CT Load	64	MW	10 Deg F - Winter Condition (Note: 49 MW in summer)
Fuel	Fuel oil #2		
Maximum Heat Input at 10 F ambient	838	mmbtu/hr	Croydon TV permit
NOX Permit Limit	0.7	lb/mmbtu	Croydon TV permit
NOX Permit Limit	586.6	lb/hr	Croydon TV permit
NOX Permit Limit at 100% CF per CT	2569	tpy/CT	calculated
NOX Permit Limit at 100% CF for all 8 CTs	20554	tpy/all 8 CTs	calculated
Permitted capacity factor for each CT	20%		TV permit
NOX Permit Limit at site average CF for all 8 CTs	4111	tpy/all 8 CTs	calculated
Design Control Condition:			
Baseline Uncontrolled Emissions	180	ppmvd @15% O2	Estimated based on lbs/MMBTU limit in TV permit
	0.700	lbs/MMBTu	Title V permit
Presumptive RACT	96	ppmvd @15% O2	PADEP 129.112(g)(2)(ii)(C) Presumptive RACT
	0.373	lbs/MMBTu	calculated
NOx Control per CT	0.327	lbs/MMBTu/CT	calculated
% control	46.7%		calculated
Annual NOx Controlled at 100% capacity factor	1199.01	tpy/CT	calculated
Permitted Capacity Factor	20%	each	
Average capacity factor for site	20%		
Annual NOx Controlled at permitted capacity factor	239.80	tpy/CT	calculated
No. of units at Facility	8		
Total NOx Controlled at Permitted Capacity Factors	1918.42	tpy for all 8 CTs	calculated
Labor Requirements			
Hourly Cost of Operation Labor	$73.80	per hour	Based on annual burdened rate of $147607 and 2000 hrs/yr
Hourly Cost of Maintenance Labor	$73.80	per hour	Based on annual burdened rate of $147607 and 2000 hrs/yr
Hourly cost of supervisory labor	$82.79	per hour	Based on annual burdened rate of $165,585 and 2000 hrs/yr
Estimated annual operating labor at site - Water Injection	2000	hrs/yr	Estimated 2000 hrs per year of operation - one (1) operator present during operation
Estimated annual maintenance labor at site - Water Injection	52	hrs/yr	Routine and emergency maintenance; Station is curremtly unmanned
Estimated annual operating labor at site - SCR	2000	hrs/yr	Estimated 2000 hrs per year of operation - one (1) operator present during operation
Estimated annual maintenance labor at site - SCR	52	hrs/yr	Routine and emergency maintenance; Station is curremtly unmanned
Estimated supervisory labor as percentage of op/main labor	10%		Estimated
Economic Factors			
Life of Units	20	years	
Construction Period - water Injection	1	year	Site-specific estimate based on staging of construction
State tax (PA)	6%	Pennsylvania state tax	
Local tax	0%	Outside Philadelphia	
Interest during construction	4.7%	Constellation Data	
Interest on Capital	10.0%	Constellation Data	
Reagent/Fuel			
Delivered Demin Water Cost	$13.00	$/1000 gal	Based on Constellation data for similar sites
Fuel oil heating value	137560	BTU/Gallon	TV Permit
Delivered #2 Fuel Oil Cost	$3.12	$/gallon	Constellation data
Electricity cost for site	$183.08	$/MWH	Site Data
Performance Impacts			
Estimated net heat rate increase for water injection	2.00%	Estimated from vendor (GE) communication	

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RACT III Control Technology Cost Evaluation

Table C-3: Capital Costs for Water Injection

Item				Basis	Unit Cost	Subtotal	Total
DIRECT COSTS							
• **Purchased Equipment**							
Purchased Equipment (PE)						$16,687,485	
	(8) Water injection system GE supply			GE proposal	$9,920,000		
	Laser scan survey (total for all units)			GE proposal	$139,236		
	(8) GE Mark Vie controls upgrade			GE proposal	$3,936,000		
	(8) NOx analyzers @$50k each			Engr Estimate	$492,000		
	(3) On-site Monitoring Lite Instrumentation			GE proposal	$47,749		
	(2) 1 million gallon demineralized water storage tanks & pumps			Engr Estimate	$2,152,500		
Freight & Tax Subtotal						$1,835,623	
	Freight	5.0%	assumed	% of PE	$834,374		
	Sales Tax	6.0%	Site	% of PE	$1,001,249		
	Local tax	0.0%					
Purchased Equipment Cost (PEC)						**$18,523,108**	
• **Direct Installation Cost**							
Foundations & Supports		8.0%	OAQPS	% of PEC		$1,481,849	
Handling and Erection		20.0%		% of PEC	Eng Estimate for site	$3,704,622	
Site Prep including relocation of interferences		10.0%	OAQPS	% of PEC		$1,852,311	
Buildings		0.0%		% of PEC	None needed	$0	
Electrical (MCC, wiring, control dashboards)		4.0%	OAQPS	% of PEC		$740,924	
Piping (All including recirculation except from vendor)		2.0%	OAQPS	% of PEC		$370,462	
Insulation, heat tracing		4.0%		% of PEC		$740,924	
Painting		2.0%		% of PEC		$370,462	
Direct Installation Cost (DIC)						**$9,261,554**	
Total Direct Costs (TDC)							**$27,784,662**
INDIRECT INSTALLATION COSTS							
• **Engineering and Project Management**		10.0%	OAQPS	% of PEC		$1,852,311	
• **Construction and Field Expenses**		5.0%	OAQPS	% of PEC		$926,155	
• **Contractor Fees**		10.0%	OAQPS	% of PEC		$1,852,311	
• **Start-up**		2.0%	OAQPS	% of PEC		$370,462	
• **Performance Test including initial RATA**				Estimate		$10,000	
• **Contingencies**		20.0%	OAQPS	% of PEC		$3,704,622	
• **Interest During Construction**				TDC*I*n		$1,305,879	
Construction Period (n)		1	Years				
Interest Rate (I)		4.7%		Constellation data			
Total Indirect Installation Costs (TIIC)							**$10,021,740**
TOTAL INSTALLED COST (TIC)							**$37,806,402**

Basis:
1: Retrofit of eight (8) GE 7B combustion turbines. to reduce NOx to 96 ppmvd @15% O2 (RACT Presumptive Limit).
2: Cost of water injection system including injection skid, piping from skid to combustors, new shower head liquid fuel nozzles, revised control curve, and laser scan survey for developing system layout from General Electric October 7, 2016 budgetary proposal, updated in December 2022.
3: Cost of controls upgrade to GE Mark VIe required for GE to incorporate water injection control program and associated combustor tuning per GE October 7, 2016 budgetary price; GE price includes hardware and installation.
4: Cost of demineralized water receiving and storage system (tank sized for maximum 144 hours of full load operation of all eight units) from engineering estimates.
5: All other costs are based on either percentages for generic plants per OAQPS manual or engineering judgement based on site specific data.

Notes

Cost for GE Mark Vie controls upgrade per combustion turbine =	$492,000	Updated value from GE 12/2022
Cost for GE water injection scope of supply per combustion turbine including the revised control curve=	$1,240,000	Updated value from GE 12/2022
Cost for site laser scan survey =	$139,236	Updated value from GE 12/2022
Cost to Install GE remote monitoring to maintain required reliability	$47,749	Updated value from GE 12/2022
Full load water injection rate per combustion turbine (GE Data)=	27400	lb/h
Full load water usage with all Combustion turbines operating at full load =	219200	lb/h
	438	gpm
Minimum demineralized water storage requirement =	1,892,374	gallons

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RACT III Control Technology Cost Evaluation
Table C-4: Operating and Annualized Costs for Water Injection

Item	Variables	Basis	Unit Cost	Subtotal	Total
Total Direct Costs (TDC)	*(Calculated on previous table)*				**$27,784,662**
TOTAL INSTALLED COST (TIC)	*(Calculated on previous table)*				**$37,806,402**
ANNUAL COSTS					
• **Utilities Cost**				$333,199	
Utility Rate	183.077 $/MW-hr	estimated			
Capacity	1,820 MW-hr/yr				
• **Demin water Cost**				$598,621	
Total Utilities Cost					**$931,820**
• **Additional Operation and Maintenance (O&M) Cost**					
Annual Maintenance Labor Cost				$3,838	
Annual operating Labor Cost				$147,607	
Annual supervosry Labor cost				$16,989	
Annual testing cost including RATA			estimate	$10,000	
Annual Maintenance Material Cost				$59,900	
Annual Inspection Cost				$24,333	**$262,667**
• **Fuel Penalty**					
Additional fuel cost for compensating higher heat rate				$5,327,955	**$5,327,955**
• **Capacity Change Credit**				$0	**$0**
Total Direct (O&M) Cost					**$6,522,442**
ADDITIONAL INDIRECT ANNUAL COSTS					
• **Overhead**	60%	% of O&M - OAQPS			**$3,913,465**
• **Administrative Charges**	2%	% of TCI - OAQPS			**$756,128**
• **Annual Contingency**	5%	% of TDC - OAQPS			**$1,389,233**
• **Property Taxes**	1%	% of TCI - OAQPS			**$378,064**
• **Insurance**	1%	% of TCI - OAQPS			**$378,064**
Total Additional Indirect Costs					**$6,814,954**
Additional Total Direct and Indirect Annual Costs (TIIC)					**$13,337,396**
• **Capital Recovery Cost**		TCI*CRF - OAQPS			**$4,440,726**
Life (n)	20	assumed			
Interest Rate (i)	0.10	Constellation Input			
Capital Recovery Factor (CRF)	0.1175	$(i*(1+i)^n)/((1+i)^n-1)$			
TOTAL ANNUAL COSTS					**$17,778,122**

COST EFFECTIVENESS ANALYSIS (Total Annual Costs / Emissions Reduction) based on Average Permitted Capacity Factor of 23.8%	
Total Annual Costs:	**$17,778,122**
NOx Emissions - Reduction (TPY):	1918.42
Cost Effectiveness ($/Ton):	**$9,267**

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Table C-5: Water Injection Supporting Calculations

Electricity Cost Calculation:

No. of combustion turbines	8	#	Comments
Demineralized Water Tank Pumps, power	170	hp	Required water pressure at water injection skid: 15-65 psig per GE; full load water injection rate is 438 gpm; pressure at combustor showerhead estimated at 200 psig
Annual hours of operation	8760	hr/yr	
Average capacity factor for site	20.0%		TV permit
Expected annual hour of operations for pumps	1752	hr/yr	
Annual power consumption for pumps	1,777	MW-hr/yr	Calculated
Demin water storage tank heaters	2	#	
Tank heater power	30	kw	Tank heater average winter electric usage
Annual hours of operation winter only	720	hr/yr	4 months in a year (winter) - 6 hours a day (during night when ambient is <32 F)
Annual power consumption heater	43	MW-hr/yr	Calculation
Total Additional Parasitic Power Requirements	1,820	MW-hr/yr	
Cost of electricity Generation at site:	$183.08	per MW-hr	Site data
Annual electricity cost:	$333,199	per year	Calculation

Demineralized Water Cost Calculations:

Water usage rate per CT	27400	lb/hr	Vendor (GE) Data
No. of CTs operating	8	# of units	
Total water usage at site	219200	lbs/hr	
Total hours per year	8760	hrs/yr	
Site average capacity factor	20.0%		TV permit
Annual water usage rate	384038400	lbs/yr	
	46048	1000 gals/yr based on water density of 8.34 lbs/gal	
Delivered cost of Demin water	13	$/1000 gal	Based on Constellation data for similar sites
Annual cost of water	$598,621	per year	Calculation

Labor Costs

Operating Labor

Annual operating labor requirements per shift for site	2000	hrs/yr	Estimated 2000 hrs per year of operation - one (1) operator present during operation
Site specific labor costs for operating labor	$73.80	$/hr	site data
Annual operating labor cost	$147,607	$/yr	

Maintenance labor

Annual maintenance labor requirements per shift for site	52	hrs/yr	Routine and emergency maintenance; Station is curremtly unmanned
Site specific labor costs for operating labor	$73.80	$/hr	Site data
Annual operating labor cost	$3,838	$/yr	

Supervisory Labor:

Supervisory Labor hours	205	hr/yr	10%	of operating & maintenance labor
Supervisory labor rate	$82.79	$/hr		
Supervisory Labor cost	$16,989	$/yr		

Total labor cost	$168,434	$/yr	

Maintenance Material & Inspection Cost

Maintenance material cost for site per year	$59,900	per yr	Same as 2012 RACT Study
Inspection Cost (combustion system) for Site per 3 years	$73,000	per 3 years	Same as 2012 RACT Study
Annual inspection cost	$24,333	per year	calculated

Fuel Penalty Cost:

Net estimated heat rate increase at NOx limit of 96 ppmvd @15% O2	2.00%	Based on vendor (GE) communication	
Rating of each simp0le cycle unit	838	MMBTU/hr	
Capacity factor for simple cycle units	20%		
Average permitted capacity factor for station	20%		
Total annual heat input for station at site average capacity factor	11745408	MMBTU/yr	basis: 8 units
Additional heat input due to heat rate increase due to water injection	234908	MMBTU/yr	incremental value due to increase in heat rate
Fuel oil high heating value	137560	Btu/gal	Station TV Permit Data
Additional fuel oil requirement	1707678	gal/yr	
Delivered cost of fuel oil at site	$3.12	$/gal	Site data: Ref John Tissue email dated October 10, 2016
Additional fuel cost at site for all 8 CTs	$5,327,955	$/yr	for all 8 CTS

Capacity Change Credit

Capacity change credit is the revenue gained by the facility due to increased output of the facility for operating water injection. The facility plans to maintain the permitted capacity (64 MW) because the safety and operability impacts of higher generation capacity on downstream electrical equipment are unknown at this time. The facility will increase the fuel input to compensate lower heat rate as shown above under Fuel Penalty Cost. Therefore, capacity change credit is not calculated.

From: Whelton, Jeffrey J (GE Gas Power) <jeffrey.whelton@ge.com>
Sent: Wednesday, December 14, 2022 2:32 PM
To: Hatton III, Albert Miller M:(Constellation Power - TSA) <Albert.Hatton@constellation.com>; Del Grosso, Anthony:(Constellation Power) <anthony.delgrosso@constellation.com>
Subject: Updated 2022 Estimates. FW: GE proposals

Hello Al, Tony:

Below are the updated 2022 estimates for the SCR System and Water Injection System.

All CPI Inflation 2016-2022: +23%
Series Title: PPI Commodity data for Metals and metal products, not seasonally adjusted 2016-2022: +57%
PPI Commodity data for Metals: 60%
All CPI Inflation: 40%
Total Application Escalation 2016-2022: 43.4%

2022 7B SCR System Budget Estimate: $17.52M
2022 Water Injection System Budget Estimate Per Gas Turbine: $1.24M

The budgetary estimates and scopes are subject to change. The estimates are intended only to assist in CEG's budget planning and does not constitute a firm quotation on the part of GE.

Thank you.

Jeff

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