DOCKETED

Docket Number:	08-AFC-10C
Project Title:	Lodi Energy Center Project
TN #:	261323
Document Title:	Preliminary Determination of Compliance
Description:	SJVAPCD's preliminary air quality compliance analysis of LEC's proposed turbine upgrade project.
Filer:	Andres Perez
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	1/28/2025 9:27:05 AM
Docketed Date:	1/28/2025

December 12, 2024

Rafael Santana
Northern California Power
12745 N Thornton Rd
Lodi, CA 95242

Re: Notice of Preliminary Decision – Preliminary Determination of Compliance
Facility Number : N-2697
Project Number: N-1243995

Dear Mr. Santana:

Enclosed for your review and comment is the District's analysis of Northern California Power's application for a Determination of Compliance for replacement/upgrade of internal combustor components of the existing gas turbine under permit N-2697-5, at 12745 N Thornton Rd, Lodi. You requested that a Certificate of Conformity with the procedural requirements of 40 CFR Part 70 be issued with this project.

The notice of preliminary decision for this project has been posted on the District's website (www.valleyair.org). After addressing all comments made during the 30-day public notice period and the 45-day EPA comment periods, the District intends to issue the Final Determination of Compliance. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Matthew Robinson of Permit Services at (209) 557-6454.

Sincerely,

Brian Clements
Director of Permit Services

BC: mr

Enclosures

cc: Courtney Graham, CARB (w/ enclosure) via email
cc: EPA Region 9 Air Permitting Manager (w/ enclosure) via EPS

DETERMINATION OF COMPLIANCE EVALUATION

Northern California Power Agency (Lodi Energy Center)
California Energy Commission
Application for Certification Docket #: 08-AFC-10C

Facility Name: Northern California Power Agency
Mailing Address: 12745 N Thornton Rd
Lodi, CA 95241-1478

Contact Name: Raphael Santana
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Alternate Contact: Jeff Adkins, Consultant
E-Mail: jadkins@trinityconsultants.com

Engineer: Matthew Robinson, Air Quality Engineer
Lead Engineer: James Harader, Supervising Air Quality Engineer
Date: December 12, 2024

District Project #: N-1243995
Permit #: N-2697-5-9
Submitted: July 25, 2024
Deemed Complete: August 13, 2024

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I. Proposal

Northern California Power Agency (NCPA) operates a 294 MW combined-cycle electric generation plant (also referred as "Lodi Energy Center (LEC)") consisting of a Siemens natural gas-fired STG6-5000F "Flex Plant™ 30" turbine equipped with Siemens ultra low-NOx (ULN) combustors, an unfired heat recovery steam generator (HRSG), and a steam operated gas turbine. The gas turbine system is equipped with a selective catalytic reduction (SCR) system to reduce NOx emissions and an oxidation catalyst system to reduce VOC and CO emissions.

NCPA has proposed modifications to the combustors to install "Gas Turbine FX Upgrade" technologies which improve thermal efficiency during high ambient temperatures. Specifically, the modifications include replacement of hot gas path components including blades, seals, vanes, and vane carriers from turbine stages 1 through 4.

The modifications will allow an increase in maximum hourly heat input rate from 2,109 MMBtu/hr to 2,166 MMBtu/hr (~2.7% increase), and increases generating capacity from 294 MW to 311 MW (~5.8% increase, 206 MW gas turbine + 105 MW steam turbine). The slight increase in heat input rate will lead to higher hourly emission rates. The facility's permits includes mass quarterly emission limits that effectively limit annual emissions from the turbine. The applicant is not proposing to increase those permitted limits. Furthermore, the turbine has operated at an average capacity level that demonstrates that the unit could reliably operate at a capacity that would fully achieve the permitted emission levels.

PTO N-2697-5-8 has been implemented and serves as the base document. Draft permit requirements for this permitting action (N-2697-5-9) are included in Appendix A. Current PTO N-2697-5-8 is included as Appendix B.

NCPA received their Title V Permit on January 7, 2020. The Title V Permit was renewed on August 6, 2024. This modification can be classified as a Title V Minor Modification pursuant to Rule 2520, and can be processed with a Certificate of Conformity (COC). Since the facility has specifically requested that this project be processed in that manner, the 45-day EPA comment period will be satisfied prior to the issuance of the Authority to Construct. NCPA must apply to administratively amend their Title V permit.

NCPA submitted a petition (referred to as an Application for Certification (AFC)) to the California Energy Commission (CEC) to amend its license on June 11, 2024 to address the changes resulting from the Gas Turbine FX Upgrade Project (08-AFC-10C). Currently, this project is going through the licensing process led by the CEC. Pursuant to SJVAPCD Rule 2201, Section 5.8, the District is required to submit a Determination of Compliance (DOC) to the CEC within 240 days after acceptance of an application as complete. A DOC is functionally equivalent to an Authority to Construct (ATC) provided that the CEC approves the AFC and the certificate granted by the CEC includes all conditions of the DOC. This document constitutes the DOC. The CEC is the lead agency for determining California Environmental Quality Act (CEQA) requirements for this project.

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (4/20/23)
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 2520	Federally Mandated Operating Permits (6/20/24)
Rule 4001	New Source Performance Standards (4/14/99)
Rule 4002	National Emissions Standards for Hazardous Air Pollutants (5/20/04)
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4301	Fuel Burning Equipment (12/17/92)
Rule 4703	Stationary Gas Turbines (9/20/07)
Rule 4801	Sulfur Compounds (12/17/92)
CH&SC 41700	Health Risk Assessment
CH&SC 42301.6	School Notice

Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. Project Location

The equipment is located at 12745 N Thornton Road in Lodi, California. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

Combustion turbine air flows through the inlet air filters, evaporative cooler and associated air inlet ductwork, is compressed in the gas turbine compressor section, and then enters the combustion turbine section. Natural gas fuel is injected into the compressed air in the combustion section and the mixture is ignited. The hot combustion gases expand through the power turbine section of the turbine, causing the shaft that drives both the electrical generator and the turbine compressor to rotate. The hot combustion gases exit the turbine section and enter the HRSG, where they heat up the feedwater that is being pumped into the HRSG. The feedwater becomes superheated steam, which is delivered to the steam turbine at high pressure (HP), intermediate pressure (IP) and low pressure (LP). The use of multiple steam delivery pressures results in an increase in cycle efficiency and flexibility. The steam is condensed and recirculated through the HRSG system. Condenser cooling water circulates through a mechanical draft evaporative cooling tower where the heat absorbed from the condenser is rejected to the atmosphere.

This facility uses Siemens' "Flex-Plant™ 30" technology to lower emissions from the combustion turbine during the startup period. An auxiliary boiler is being used as part of Flex-Plant package to pre-heat the combustion turbine fuel and to provide steam turbine sealing steam prior to the combustion turbine startup. This technology reduces the startup time, thereby, expected to reduce the startup emissions.

Flue gases due to combustion of natural gas fuel in the gas turbine are vented through an SCR system for control of NOx emissions, and an oxidation catalyst for control of CO and VOC emissions.

V. Equipment Listing

Pre-Project Equipment Description:

N-2697-5-8: 294 MW (NOMINAL) COMBINED-CYCLE ELECTRIC GENERATION PLANT CONSISTING OF A SIEMENS INDUSTRIAL FRAME "FLEX PLANT 30" STG6-5000F NATURAL GAS-FIRED TURBINE ENGINE WITH ADVANCED ULTRA LOW-NOX COMBUSTOR SYSTEM, AN UNFIRED HEAT RECOVERY STEAM GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION WITH AMMONIA INJECTION AND AN OXIDIZATION CATALYST AND A STEAM TURBINE GENERATOR

Proposed Modification:

NCPA has proposed modifications to the combustors to install “Gas Turbine FX Upgrade” technologies which improve thermal efficiency during high ambient temperatures. Specifically, the modifications include replacement of hot gas path components including blades, seals, vanes, and vane carriers from turbine stages 1 through 4. The modifications allow increased heat input rate (HHV) from 2,109 MMBtu/hr to 2,166 MMBtu/hr, and increases the nominal output to 311 MW (206 MW gas turbine + 105 MW steam turbine).

N-2697-5-9: MODIFICATION OF 294 MW (NOMINAL) COMBINED-CYCLE ELECTRIC GENERATION PLANT CONSISTING OF A SIEMENS INDUSTRIAL FRAME "FLEX PLANT 30" STG6-5000F NATURAL GAS-FIRED TURBINE ENGINE WITH ADVANCED ULTRA LOW-NOX COMBUSTOR SYSTEM, AN UNFIRED HEAT RECOVERY STEAM GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION WITH AMMONIA INJECTION AND AN OXIDIZATION CATALYST AND A STEAM TURBINE GENERATOR: MODIFICATIONS TO COMBUSTOR TO INSTALL GAS TURBINE FX TECHNOLOGIES

Post-Project Equipment Description:

N-2697-5-9: 311 MW (NOMINAL) COMBINED-CYCLE ELECTRIC GENERATION PLANT CONSISTING OF A SIEMENS INDUSTRIAL FRAME "FLEX PLANT 30" STG6-5000F NATURAL GAS-FIRED TURBINE ENGINE WITH ADVANCED ULTRA LOW-NOX COMBUSTOR SYSTEM, AN UNFIRED HEAT RECOVERY STEAM GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION WITH AMMONIA INJECTION AND AN OXIDIZATION CATALYST, AND A STEAM TURBINE GENERATOR

VI. Emission Control Technology Evaluation

The applicant is not proposing any changes to the existing emission control technologies. The control technologies implemented on this turbine are discussed below.

A ultra-low NOx combustor system and a selective catalytic reduction (SCR) system with ammonia injection are utilized to reduce the NOx emissions. The combustor system minimizes NOx formation by controlling combustion temperature. The SCR system selectively reduces NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. The permit contains conditions specifying parameters for optimal performance of the SCR system, as well as conditions requiring demonstrated attainment of prescribed NOx emission levels. Additionally, this permit contains conditions limiting emission of unreacted NH_3.

An oxidation catalyst is used to reduce the emissions of CO and VOC. The NCPA oxidation catalyst uses a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO_2). No reagents are used upstream of the catalyst. The permit contains conditions specifying parameters for optimum performance of the oxidation catalyst system, as well as conditions requiring demonstrated attainment of prescribed CO and VOC emission levels.

NCPA controls PM emissions with inlet air filters, lube oil coalescer. The inlet air filters will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted into the atmosphere. The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

VII. General Calculations

A. Assumptions

- To streamline emission calculations, $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions. Only if needed to determine if a project is a Federal major modification for $PM_{2.5}$, then specific $PM_{2.5}$ emission calculations will be performed.
- Other assumptions will be stated as they are made during the evaluation.

B. Emission Factors

1. Pre-Project Emission Factors (EF1)

The following table summarizes the emission factors.

Pollutant	EF1 (startup, shutdown, and combustor tuning)	EF1 (normal operation)	Source
NO_x	160.0 lb/hr	2.0 ppmvd @ 15% O_2 and 15.54 lb/hr	Permit to Operate N-2697-5-8
SO_x	6.1 lb/hr	6.1 lb/hr	
PM_{10}	9.0 lb/hr	9.0 lb/hr	
CO	1,500.0 lb/hr	2.0 ppmvd @ 15% O_2 and 9.46 lb/hr	
VOC	16.0 lb/hr	1.4 ppmvd @ 15% O_2 and 3.79 lb/hr	
NH_3	28.76 lb/hr	10.0 ppmvd @ 15% O_2 and 28.76 lb/hr	

2. Post Project Emission Factors (EF2)

The following table summarizes the proposed post-project emission factors.

- NCPA has proposed to retain existing startup/shutdown/tuning NOx, PM10, CO, and VOC emission rate, and reset the SOx and NH3 emissions to the emission rate during normal operation.

- During normal operation, the potential hourly emission rates are expected to increase proportionately as a result of the increase in maximum firing rate from 2,109 MMBtu/hr to 2,166 MMBtu/hr. Hourly emissions form NOx, SOx, CO and VOC are estimated as follows:

  PE2 (lb/hr) = PE1 (lb/hr) x (2,166 MMBtu/hr ÷ 2,109 MMBtu/hr)

- NCPA has proposed to retain the existing hourly PM10 emission rate.

Emission factors which increase as a result of this project are indicated in bold.

Pollutant	EF2 (startup, shutdown, and combustor tuning)	EF2 (normal operation)	Source
NO_x	160.0 lb/hr	2.0 ppmvd @ 15% O_2 and **15.96 lb/hr**	Applicant's proposal
SO_x	**6.27** lb/hr	**6.26 lb/hr**	
PM_{10}	9.0 lb/hr	9.0 lb/hr	
CO	1,500.0 lb/hr	2.0 ppmvd @ 15% O_2 and **9.72 lb/hr**	
VOC	16.0 lb/hr	1.4 ppmvd @ 15% O_2 and **3.89 lb/hr**	
NH_3	**29.54** lb/hr	10.0 ppmvd @ 15% O_2 and **29.54 lb/hr**	

C. Calculations

1. Pre-Project Potential to Emit (PE1)

The following table summarizes the daily emissions with or without startup/shutdown and or combustor tuning activities, as calculated in project N-1211670.

Note that the permit limits emissions of each pollutant on a quarterly basis. These quarterly emissions are used to determine the annual emissions shown in the table below.

Pollutant	PE1 (lb/day) with startup/shutdown/ combustor tuning activities	PE1 (lb/day) without startup/shutdown/ combustor tuning activities	PE1 (lb/yr)
NO_x	879.7	373.0	151,415
SO_x	146.4	146.4	53,436
PM_{10}	216.0	216.0	78,840
CO	5,570.3	227.0	198,000
VOC	164.2	91.0	33,003
NH_3	690.3	690.3	251,938

2. Post-Project Potential to Emit (PE2)

The project results in a small increase in maximum firing rate, which results in increases in maximum hourly and daily emission rates on days without a startup, shutdown, or combustor tuning. NCPA is not proposing to change emission rates on a quarterly or annual basis; NCPA is not proposing to change NOx, PM10, CO, or VOC emission rates on days when startup/shutdown or combustor tuning occurs (there is sufficient compliance margin in these limits to account for small increases in hourly emission rates). PE2 is calculated by the equations shown below. PE2, with increases indicated in bold, is summarized in the following table.

PE2 (lb/day) = PE2 (lb/hr) x 24 hr/day

Pollutant	PE2 (lb/day) with startup/shutdown/ combustor tuning activities	PE2 (lb/day) without startup/shutdown/ combustor tuning activities	PE2 (lb/yr)
NO_x	879.7	**383.0**	151,415
SO_x	**150.4**	**150.2**	53,436
PM_{10}	216.0	216.0	78,840
CO	5,570.3	**233.3**	198,000
VOC	164.2	**93.4**	33,003
NH_3	**709.0**	**709.0**	251,938

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site, including all ERCs held as certificates and all emission reduction credits sold or transferred.

The SSPE1 can be calculated by adding the PE1 from all units with valid ATCs or PTOs and the sum of the ERCs that have been banked at the source and which have not been used on-site ($Total_{ERC}$). The SSPE1 is obtained from project N-1211670

$SSPE1_{Total} = SSPE1_{Permit\ Unit} + Total_{ERC}$

SSPE1 (lb/year)						
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**	**NH_3**
N-2697-1-8	40,880	11,571	17,520	117,530	19,992	137,900**
N-2697-4-5	97	0	4	23	7	0
N-2697-5-8	151,415	53,436	78,840	198,000	33,003	251,938
N-2697-6-2	0	0	8,176	0	0	0
N-2697-7-2	1,240	416	1,108	---*	616	0
ERC	0	0	0	0	0	0
SSPE1	**193,632**	**65,423**	**105,648**	**315,553**	**53,618**	**389,838**

*Total CO emissions from units N-2697-5 and N-2697-7 were limited to 198,000 lb/year.
**Ammonia slip from N-2697-1-8 is limited to 25 ppmvd @ 15% O2 (0.034 lb-ammonia/MMBtu), and 463 MMBtu/hr (4,055,880 MMBtu/yr). Potential emissions of ammonia are estimated as follow: 0.034 lb-ammonia/MMBtu × 4,055,880 MMBtu/yr = 137,900 lb-ammonia/yr

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source, except for emissions units proposed to be shut down as part of a Stationary Source Project, and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site, including all ERCs held as certificates and all emission reduction credits sold or transferred.

This project does not result in any change to SSPE. Therefore, SSPE2=SSPE1.

SSPE2 (lb/year)						
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**	**NH_3**
N-2697-1-8	40,880	11,571	17,520	117,530	19,992	137,900
N-2697-4-5	97	0	4	23	7	0
N-2697-5-9 (ATC)	151,415	53,436	78,840	198,000	33,003	251,983
N-2697-6-2	0	0	8,176	0	0	0
N-2697-7-2	1,240	416	1,108	---*	616	0
ERC	0	0	0	0	0	0
SSPE2	**193,632**	**65,423**	**105,648**	**315,553**	**53,618**	**389,838**

5. Major Source Determination

<u>Rule 2201 Major Source Determination:</u>

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status, the following shall NOT be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months), pursuant to the Clean Air Act, Title 3, Section 302, US Codes 7602(j) and (z)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)						
	NOx	**SOx**	**PM10**	***PM2.5**	**CO**	**VOC**
SSPE1	193,632	65,423	105,648	105,648	315,553	53,618
SSPE2	193,632	65,423	105,648	105,648	315,553	53,618
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	Yes	No	No	No	Yes	Yes

*PM2.5 assumed to be equal to PM10

NCPA is an existing Major Source for NOx, CO, and VOC emissions and will remain a Major Source for these pollutants.

<u>Rule 2410 (Prevention of Significant Deterioration) Major Source Determination:</u>

The facility or the equipment evaluated under this project is listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 100 tpy for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO_2	**VOC**	**SO_2**	**CO**	**PM***	**PM10**
Estimated Facility PE before Project Increase	97	27	33	158	53	53
PSD Major Source Thresholds	100	100	100	100	100	100
PSD Major Source?	No	No	No	Yes	No	No

*PM assumed to be equal to PM10.

As shown above, the facility is an existing PSD major source for at least one pollutant.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the Quarterly Net Emissions Change (QNEC), and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

As shown in Section VII.C.5 above, the facility is a Major Source for NOx, CO, and VOC.

a. BE NOx

Pursuant to Rule 2201, a Clean Emissions Unit is defined as an emissions unit that is equipped with an emissions control technology with a minimum control efficiency of at least 95% or is equipped with emission control technology that meets the requirements for achieved-in-practice BACT as accepted by the APCO during the five years immediately prior to the submission of the complete application.

In the 2021 project N-1211670 the equipment under this permit was found to meet the requirements for achieved-in-practice BACT of District BACT guideline 3.4.2 (gas turbine ≥50 MW uniform load with heat recovery) was considered to be 2.0 ppmvd NOx @ 15% O2 (1-hour average, excluding startup and shutdown), and fast start technology. The gas turbine under permit N-2697-5 is required to comply with 2.0 ppmvd NOx @ 15% O2 over 1-hour average period, which satisfies the achieved-in-practice BACT standard (above). Therefore, this unit qualifies as a Clean Emission Unit and the BE is set equal to PE1.

BE = PE1 = 151,415 lb-NOx/yr

b. BE SO_X

As shown in Section VII.C.5 above, the facility is not a Major Source for SO_X emissions.

Thus, BE is equal to PE1.

BE = PE1 = 53,436 lb-SOx/yr

c. BE PM10

As shown in Section VII.C.5 above, the facility is not a Major Source for PM10 emissions.

Thus, BE is equal to PE1.

BE = PE1 = 78,840 lb-PM_{10}/yr

d. BE CO

As shown in Section VII.C.5 above, the facility is a Major Source for CO emissions. Pursuant to Rule 2201, a Clean Emissions Unit is defined as an emissions unit that is equipped with an emissions control technology with a minimum control efficiency of at least 95% or is equipped with emission control technology that meets the requirements for achieved-in-practice BACT as accepted by the APCO during the five years immediately prior to the submission of the complete application.

In the 2021 project N-1211670 the equipment under this permit was found to meet the requirements for achieved-in-practice BACT of District BACT guideline 3.4.2 (gas turbine ≥50 MW uniform load with heat recovery) which required 6.0 ppmvd CO @ 15% O2. The gas turbine under permit N-2697-5 is required to comply with 2.0 ppmvd CO @ 15% O2, which is below the achieved-in-practice BACT standard (above). Therefore, this unit qualifies as a Clean Emission Unit, and the BE is set equal to PE1.

BE = PE1 = 198,000 lb-CO/yr

e. BE VOC

As shown in Section VII.C.5 above, the facility is a Major Source for VOC emissions. Pursuant to Rule 2201, a Clean Emissions Unit is defined as an emissions unit that is equipped with an emissions control technology with a minimum control efficiency of at least 95% or is equipped with emission control technology that meets the requirements for achieved-in-practice BACT as accepted by the APCO during the five years immediately prior to the submission of the complete application.

In the 2021 project N-1211670 the equipment under this permit was found to meet the requirements for achieved-in-practice BACT of District BACT guideline 3.4.2 (gas turbine ≥50 MW uniform load with heat recovery) which required less than or equal to 2.0 ppmvd VOC (as methane) @ 15% O2. The gas turbine under permit N-2697-5 is required to comply with 1.4 ppmvd VOC (as methane) @ 15% O2, which is below the achieved-in-practice BACT standard (above). Therefore, this unit qualifies as a Clean Emission Unit, and the BE is set equal to PE1.

BE = PE1 = 33,003 lb-VOC/yr

7. Senate Bill 288 Major Modification

A Senate Bill (SB) 288 Major Modification is a federal major modification under 40 CFR 51.165 as it existed on December 19, 2002. 40 CFR Part 51.165 (12/19/02) defines a Major Modification as any physical change in or change in the method of operation of *an existing major stationary source* that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.

Per section VII.C.5 above, this facility is a Major Source for NOx, CO, and VOC. Since San Joaquin Valley air basin is in attainment for CO emissions, no SB-288 threshold was established for CO emissions. This project's PE2 for NOx and VOC emissions, as calculated in Section VII above, is compared to the SB 288 Major Modification Thresholds in the following table in order to determine if further SB 288 Major Modification calculation is required.

SB 288 Major Modification Thresholds			
Pollutant	**Project PE2 (lb/year)**	**Threshold (lb/year)**	**SB 288 Major Modification Calculation Required?**
NO_x	151,415	50,000	Yes
VOC	33,003	50,000	No

Since the project's PE2 surpasses the SB 288 Major Modification Thresholds for NOx, the project Net Emissions Increase (NEI) will be compared to the SB 288 Major Modification thresholds in order to determine if this project constitutes an SB 288 Major Modification.

The project NEI is the total of emission increases for every permit unit addressed in this project and is calculated as follows:

NEI = ∑(PE2 – AE)

Where: PE2 = The sum of all the PE2s for each permit unit in this project
AE = Actual emissions, as of a particular date, shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a consecutive 24-month period which precedes the particular date and which is representative of normal source operation. The reviewing authority shall allow the use of a different time period upon a determination that it is more representative of normal source operation

As seen in the table above,

PE2 = 151,415 lb-NOx/yr

NCPA submitted NOx emissions data from January 2019 to May 2024 (Appendix C). The data between May 2021 through April 2023 represents the 24-month normal source operation. The annual average NOx emissions were 59,438 pounds per year. Thus,

AE = 59,438 lb-NOx/yr

The PE2 and AE values used to calculate the NEI and make the SB 288 Major Modification determination in the following table.

SB 288 Major Modification Calculation and Determination					
Pollutant	**PE2 (lb/yr)**	**AE (lb/yr)**	**NEI (lb/yr)**	**Thresholds (lb/yr)**	**SB 288 Major Modification?**
NO_x	151,415	59,438	91,977	50,000	Yes

As demonstrated in the preceding table, this project constitutes an SB 288 Major Modification for NOx emissions.

8. Federal Major Modification / New Major Source

Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

As defined in 40 CFR 51.165, Section (a)(1)(v) and part D of Title I of the CAA, a Federal Major Modification is any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act. The significant net emission increase threshold for each criteria pollutant is included in Rule 2201.

NCPA is a Major Source for NOx, CO and VOC emissions. SJV is in attainment with the ambient air standard for CO; therefore, there is no significance threshold for CO in Table 3-1 of Rule 2201 and the CO project emissions increase will not be calculated. The NOx and VOC net emissions increases are estimated below.

The determination of Federal Major Modification is based on a two-step test. For the first step, only the emission *increases* are counted. In step 1, emission decreases can not cancel out the increases. Step 2 allows consideration of the project's net emissions increase as described in 40 CFR 51.165 and the Federal Clean Air Act Section 182 (e), as applicable.

Step 1: Project Emissions Increase

For modified existing emissions units, according to 40 CFR 51.165(a)(2)(ii)(C), the project's emission increase for each pollutant is equal to the sum of the differences between the projected actual emissions (PAE) and the baseline actual emissions (BAE). Please note that in step 1, since the District is classified as extreme non-attainment for ozone, no NOx and VOC emission decreases associated with the proposed project shall be accounted for.

Project Emissions Increase = $\sum(PAE - BAE)$

As described in 40 CFR 51.165(a)(1)(xxviii)(B), when using historical data and company's expected business activity to determine PAE, the portion of the emissions after the project that the existing unit could have accommodated (Unused Baseline Capacity, UBC) before the project (during the same 24-month baseline period used to determine BAE) and that are unrelated to the particular project (including emissions increases due to product demand growth) are to be excluded.

Otherwise, according to 40 CFR 51.165(a)(1)(xxviii)(B)(4), when determining PAE, in lieu of using the method described in 40 CFR 51.165 (a)(1)(xxviii)(B)(1)-(3), *Projected Actual Emissions*, the owner/operator may elect to use emissions unit's Potential to Emit. If appropriate projected actual emissions are not provided by the applicant, then the emissions unit's Potential to Emit is used to calculate the emissions increase.

Since the project proponent has provided the required historical and projected operation data (see Appendix D) required to calculate PAE, the project emissions increase will be calculated as follows:

Project Emissions Increase = PAE – BAE – UBC

Where: PAE = Projected Actual Emissions, and
BAE = Baseline Actual Emissions
UBC = Unused baseline capacity

Refer to Appendix E for detailed calculations. The following table summarizes PAE, BAE, UBC, and the Project Emissions Increase of NOx and VOC for the modified unit.

Project Net Emissions Increase For Modified Emissions Units (EI)			
Permit Unit	**Item**	**NO_X**	**VOC**
N-2697-5	PAE (lb/yr)	151,415	33,003
	BAE (lb/yr)	59,438	12,161
	UBC (lb/yr)	91,977	20,842
	EI (lb/yr)	0	0

As seen in the table above, the proposed project will not have any emissions increase for NOx or VOC emissions.

The project's combined total emission increases, as seen above, summarized and compared to the Federal Major Modification Thresholds in the following table.

Federal Major Modification Thresholds for Emission Increases			
Pollutant	**Total Net Emissions Increase (lb/yr)**	**Thresholds (lb/yr)**	**Federal Major Modification?**
NOx*	0	0	No
VOC*	0	0	No

*If there is any emission increases in NOx or VOC, this project is a Federal Major Modification and no further analysis is required.

Since none of the Federal Major Modification Thresholds are being surpassed with this project, this project does not constitute a Federal Major Modification.

Since the owner/operater has estimated the Projected Actual Emissions (PAE) based on all information relevant to the emission unit(s), the following permit condition will be added to the permit:

- If the emission unit's actual NOx, SOx, CO, PM, PM10 (all PM can be assumed to be equal to PM10), or VOC emissions exceed the actual emissions projected under project N-1243995 on a calendar year basis, the permittee must report to the District the annual emissions as calculated pursuant to paragraph 40 CFR 51.165(a)(6)(iii) or 40 CFR 52.21(r)(6)(iii) and any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection). Such information must be submitted to the District for a period of 10 calendar years beginning the year of operation under ATC N-2697-5-9 and shall be submitted within 60 days of the end of each calendar year. [District Rules 2201 and 2410]

New Major Source

This facility is not a Major Source for SOx, PM10, or PM2.5 and is not becoming a Major Source for these pollutants as a result of this project. Therefore, this project cannot constitute a New Major Source for SOx, PM10, or PM2.5.

This facility is an existing Major Source for NOx, CO, and VOC and is remaining a Major Source for these pollutants as a result of this project. Therefore, the project cannot constitute a New Major Source for NOx, CO, or VOC.

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10

As demonstrated in the "PSD Major Source Determination" Section above, the facility was determined to be a existing PSD Major Source. Because the project is not located within 10 km (6.2 miles) of a Class 1 area – modeling of the emission increase is not required to determine if the project is subject to the requirements of Rule 2410.

I. Project Emission Increase – Significance Determination

a. Evaluation of Calculated Post-project Potential to Emit for New or Modified Emissions Units vs PSD Significant Emission Increase Thresholds

As a screening tool, the post-project potential to emit from all new and modified units is compared to the PSD significant emission increase thresholds, and if the total potentials to emit from all new and modified units are below the applicable thresholds, no futher PSD analysis is needed.

PSD Significant Emission Increase Determination: Potential to Emit (tons/year)					
	NO2	**SO2**	**CO**	**PM**	**PM10**
Total PE from New and Modified Units	75.7	26.7	99.0	39.4	39.4
PSD Significant Emission Increase Thresholds	40	40	100	25	15
PSD Significant Emission Increase?	Yes	No	No	Yes	Yes

As demonstrated in the table above, because the post-project potential to emit from all new and modified emission units is greater than at least one PSD significant emission increase threshold, further analysis is required to determine if the project will result in an increase greater than the PSD significant emission increase thresholds. See step b. below for further analysis.

b. Evaluation of Calculated Emission Increases vs PSD Significant Emission Increase Thresholds

In this step, the emission increase for each subject pollutant is compared to the PSD significant emission increase threshold, and if the emission increase for each subject pollutant is below their threshold, no further analysis is required.

For existing emissions units, the increase in emissions is calculated as follows:

Emission Increase = PAE – BAE - UBC

Where: PAE = Projected Actual Emissions, and
BAE = Baseline Actual Emissions
UBC = Unused baseline capacity

The project's total emission increases, as calculated in Appendix E, are listed below and compared to the PSD significant emission increase thresholds in the following table.

PSD Significant Emission Increase Determination: Emission Increase (tons/year)					
	NO2	**SO2**	**CO**	**PM**	**PM10**
Emission Increases (only)	0	0	0	0	0
PSD Significant Emission Increase Thresholds	40	40	100	25	15
PSD Significant Emission Increase?	No	No	No	No	No

As shown in the table above, the emission increases from the project, for all new and modified emission units, does not exceed any of the PSD significant emission increase thresholds. Therefore the project does not result in a PSD major modification.

Since the owner/operater has estimated the Projected Actual Emissions (PAE) based on all information relevant to the emission unit(s), the following permit condition will be added to the permit:

- If the emission unit's actual NOx, SOx, CO, PM, PM10 (all PM can be assumed to be equal to PM10), or VOC emissions exceed the actual emissions projected under project N-1243995 on a calendar year basis, the permittee must report to the District the annual emissions as calculated pursuant to paragraph 40 CFR 51.165(a)(6)(iii) or 40 CFR 52.21(r)(6)(iii) and any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection). Such information must be submitted to the District for a period of 10 calendar years beginning the year of operation under ATC N-2697-5-9 and shall be submitted within 60 days of the end of each calendar year. [District Rules 2201 and 2410]

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix F.

VIII. Compliance Determination

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

Pursuant to District Rule 2201, Section 4.1, BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions[1]:

a. Any new emissions unit with a potential to emit exceeding 2.0 pounds per day, or the relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding 2.0 pounds per day,
b. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding 2.0 pounds per day, and/or
c. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

a. New or relocated emissions units – PE > 2.0 lb/day

As discussed in Section I above, there are no new or relocated emissions units associated with this project. Therefore BACT for new units with PE > 2 lb/day purposes is not triggered.

b. Modification of emissions units – AIPE > 2.0 lb/day

AIPE = PE2 – HAPE

Where,
AIPE = Adjusted Increase in Permitted Emissions, (lb/day)
PE2 = Post-Project Potential to Emit, (lb/day)
HAPE = Historically Adjusted Potential to Emit, (lb/day)

HAPE = PE1 x (EF2/EF1)

Where,
PE1 = The emissions unit's PE prior to modification or relocation, (lb/day)
EF2 = The emissions unit's permitted emission factor for the pollutant after modification or relocation. If EF2 is greater than EF1 then EF2/EF1 shall be set to 1
EF1 = The emissions unit's permitted emission factor for the pollutant before the modification or relocation

[1] Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

AIPE = PE2 – (PE1 ∗ (EF2 / EF1))

AIPE calculation is summarized in the table below. Emissions of NH3 are not considered as these result from the SCR system which is a control device, by definition, not an emission unit.

Pollutant	PE2 (lb/day)	PE1 (lb/day)	EF2 (lb/hr)	EF1 (lb/hr)	AIPE
NO_x	383.1	373.0	15.96	15.54	10.1
SO_x	150.4	146.4	6.27	6.1	4.0
PM_{10}	216.0	216.0	9.0	9.0	0.0
CO	233.2	227.0	9.72	9.46	6.2
VOC	93.5	91.0	3.90	3.79	2.5

AIPE is greater than 2.0 lb/day for NOx, SOx, CO, VOC. Additionally, as shown in VII.C.4, the SSPE2 for CO is greater than 200,000 lb/year. Therefore, BACT is triggered for NOx, SOx, CO, and VOC.

c. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project constitutes an SB 288 Major Modification for NOx emissions. Therefore, BACT is triggered for NOx.

2. BACT Guideline

BACT Guideline 3.4.2, which applies to gas turbines equal to or greater than 50 MW uniform load with heat recovery, was rescinded 8/16/2023. Therefore, a project specific determination is made for this project. (See Appendix G)

3. Top-Down BACT Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

Pursuant to the attached Top-Down BACT Analysis (see Appendix G), BACT has been satisfied with the following:

NOx: 2.0 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown); selective catalytic reduction; fast start technology

SOx: PUC-regulated natural gas fuel

CO: 2.0 ppmvd @ 15% O2 (3-hr average, excluding startup and shutdown); oxidation catalyst

VOC: 1.4 ppmvd @ 15% O2 (1-hr average, excluding startup and shutdown); oxidation catalyst

B. Offsets

1. District Emission Offset Requirements

a. District Offset Applicability

Pursuant to District Rule 2201, Section 4.5, District offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals or exceeds the offset threshold levels in Table 4-1 of District Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

District Offset Determination (lb/year)					
	NOx	**SOx**	**PM10**	**CO**	**VOC**
SSPE2	193,632	65,423	105,648	315,553	53,618
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets Triggered?	Yes	Yes	Yes	Yes	Yes

b. District Offset Quantity (DOQ) Required

As seen in the table above, District offsets are triggered for NOx, SOx, PM_{10}, CO and VOC emissions under Rule 2201. Therefore, offsets analysis is required for these pollutants.

<u>NOx</u>

As demonstrated above, the facility's SSPE2 for NOx is greater than the offset threshold. Therefore, offset calculations are required.

The quantity of offsets in pounds per year for NO_X is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR, for all new or modified emissions units in the project
Where,

PE2 = Post-Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

Otherwise,

BE = HAE

Per Section VII.C.6 above, BE is 151,415 lb-NOx/yr.

There is no increases in cargo carrier emissions. Therefore, offsets can be determined as follows:

Offsets Required (lb/year) = ([PE2 – BE] + ICCE) x DOR

PE2 (NO_X) = 151,415 lb/year
BE (NO_X) = 151,415 lb/year
ICCE = 0 lb/year
DOR = 1.5 (assumed)

Offsets Required (lb/year) = ([151,415 – 151,405] + 0) x 1.5
= 0 lb-NO_X/year

SOx

As demonstrated above, the facility's SSPE2 for SOx is greater than the offset threshold. Therefore, offset calculations are required.

The quantity of offsets in pounds per year for SO_X is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR, for all new or modified emissions units in the project
Where,

PE2 = Post-Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

BE = PE1 for:

- Any unit located at a non-Major Source,

- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

Otherwise,

BE = HAE

Per Section VII.C.6 above, the BE is 53,436 lb-SOx/yr.

There is no increases in cargo carrier emissions. Therefore, offsets can be determined as follows:

Offsets Required (lb/year) = ([PE2 – BE] + ICCE) x DOR

PE2 (SO_X) = 53,436 lb/year
BE (SO_X) = 53,436 lb/year
ICCE = 0 lb/year
DOR = 1.5 (assumed)

Offsets Required (lb/year) = ([53,436 – 53,436] + 0) x 1.5
= 0 lb-SO_X/year

<u>PM10</u>

As demonstrated above, the facility's SSPE2 for PM_{10} is greater than the offset threshold. Therefore, offset calculations are required.

The quantity of offsets in pounds per year for PM_{10} is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR, for all new or modified emissions units in the project
Where,

PE2 = Post-Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

Otherwise,

BE = HAE

Per Section VII.C.6 above, the BE is 78,840 lb-PM_{10}/yr.

There is no increases in cargo carrier emissions. Therefore, offsets can be determined as follows:

Offsets Required (lb/year) = ([PE2 – BE] + ICCE) x DOR

PE2 (PM_{10}) = 78,840 lb/year
BE (PM_{10}) = 78,840 lb/year
ICCE = 0 lb/year
DOR = 1.5 (assumed)

Offsets Required (lb/year) = ([78,840 – 78,840] + 0) x 1.5
= 0 lb-PM_{10}/year

<u>CO</u>

As demonstrated above, the facility's SSPE2 for CO is greater than the offset threshold. Therefore, offset calculations are required.

The quantity of offsets in pounds per year for PM_{10} is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR, for all new or modified emissions units in the project
Where,

PE2 = Post-Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

Otherwise,

BE = HAE

Per Section VII.C.6 above, the BE is 198,000 lb-CO/yr.

There is no increases in cargo carrier emissions. Therefore, offsets can be determined as follows:

Offsets Required (lb/year) = ([PE2 – BE] + ICCE) x DOR

PE2 (CO) = 198,000 lb/year
BE (CO) = 198,000 lb/year
ICCE = 0 lb/year
DOR = 1.5 (assumed)

Offsets Required (lb/year) = ([198,000 – 198,000] + 0) x 1.5
= 0 lb-CO/year

VOC

As demonstrated above, the facility's SSPE2 for VOC is greater than the offset threshold. Therefore, offset calculations are required.

The quantity of offsets in pounds per year for VOC is calculated as follows for sources with an SSPE1 greater than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = (Σ[PE2 – BE] + ICCE) x DOR, for all new or modified emissions units in the project
Where,

PE2 = Post-Project Potential to Emit, (lb/year)
BE = Baseline Emissions, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, Located at a Major Source.

Otherwise,

BE = HAE

Per Section VII.C.6 above, the BE is 33,003 lb-VOC/yr.

There is no increases in cargo carrier emissions. Therefore, offsets can be determined as follows:

Offsets Required (lb/year) = ([PE2 – BE] + ICCE) x DOR

PE2 (VOC) = 33,003 lb/year
BE (VOC)= 33,003 lb/year
ICCE = 0 lb/year
DOR = 1.5 (assumed)

Offsets Required (lb/year) = ([33,003 – 33,003] + 0) x 1.5
= 0 lb-VOC/year

District Offset Quantities
As seen in the above section, District offsets are triggered but are not required.

2. Federal Emission Offset Requirements

As demonstrated in section VII.C.8 above, this project is not a New Major Source or a Federal Major Modification for any pollutant addressed in this project. Thus, federal offsets are not triggered for this project and no further discussion is required.

C. Public Notification

1. Applicability

Pursuant to District Rule 2201, Section 5.4, public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed,
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant, and/or
e. Any project at a minor source which results in an SSPE exceeding 80% of the major source threshold for any pollutant.

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

As demonstrated in Section VII.C.7 of this evaluation, this project is an SB 288 Major Modification. Therefore, public noticing is required for this project for SB 288 Major Modification purposes.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. There are no new emissions units associated with this project. Therefore public noticing is not required for this project for PE > 100 lb/day.

c. Offset Threshold

Public notification is required if the pre-project Stationary Source Potential to Emit (SSPE1) is increased to a level exceeding the offset threshold levels. The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Thresholds (lb/year)					
	NOx	**SOx**	**PM10**	**CO**	**VOC**
SSPE1	193,632	65,423	105,648	315,553	53,618
SSPE2	193,632	65,423	105,648	315,553	53,618
Offset Threshold	20,000	54,750	29,200	200,000	20,000
Public Notice Required?	No	No	No	No	No

As demonstrated above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District Rule 2201, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds (lb/year)						
	NOx	**SOx**	**PM10**	**CO**	**VOC**	**NH_3**
SSPE2	193,632	65,423	105,648	315,553	53,618	389,838
SSPE1	193,632	65,423	105,648	315,553	53,618	389,839
SSIPE	0	0	0	0	0	0
SSIPE Public Notice Threshold	20,000	20,000	20,000	20,000	20,000	20,000
Public Notice Required?	No	No	No	No	No	No

As demonstrated above, the SSIPEs for all pollutants were less than 20,000 lb/year; therefore public noticing for SSIPE purposes is not required.

e. Minor Sources with SSPE Exceeding 80% of Major Source Threshold

Public notification is required for any project for new and/or modified stationary sources at minor source facilities that results in a SSPE exceeding 80% of the major source threshold.

80% of Major Source Thresholds (lb/year)					
	NOx	**SOx**	**PM10**	**CO**	**VOC**
SSPE1	193,632	65,423	105,648	315,553	53,618
SSPE2	193,632	65,423	105,648	315,553	53,618
80% of Major Source Threshold	16,000	112,000	112,000	160,000	16,000
Public Notice Required?	No	No	No	No	No

As demonstrated above, the SSPE2 did not surpass 80% of the major source threshold for any pollutant emitted by this project; therefore, public noticing for this purpose is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project because it is a SB288 Major Modification. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be electronically published on the District's website prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions:

- Except during startup, shutdown and combustor tuning periods, emissions from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) - 15.96 lb/hr and 2.0 ppmvd @ 15% O2; CO - 9.72 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.89 lb/hr and 1.4 ppmvd @ 15% O2; PM10 - 9.0 lb/hr; or SOx (as SO2) - 6.26 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001, and 4703]

- During start-up, and shutdown and combustor tuning periods, the emissions shall not exceed any of the following limits: NOx (as NO2) - 160.00 lb/hr; CO - 1,500.00 lb/hr; VOC (as methane) - 16.00 lb/hr; PM10 - 9.00 lb/hr; SOx (as SO2) – 6.26 lb/hr; or NH3 – 29.54 lb/hr. [District Rule 2201]

- NH3 emissions shall not exceed any of the following limits: 10.0 ppmvd @ 15% O2 over a 24-hour rolling average period and 29.54 lb/hr. [District Rule 2201]

- Emissions from the gas turbine system, on days when startup, shutdown and/or combustor tuning activities occur, shall not exceed the following limits: NOx (as NO2) - 879.7 lb/day; CO - 5,570.3 lb/day; VOC - 164.2 lb/day; PM10 - 216.0 lb/day; SOx (as SO2) – 150.4 lb/day, or NH3 – 709.0 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201]

- Emissions from the gas turbine system, on days when startup, shutdown and/or combustor tuning activities do not occur, shall not exceed the following: NOx (as NO2) - 383.0 lb/day; CO – 233.3 lb/day; VOC – 93.4 lb/day; PM10 - 216.0 lb/day; SOx (as SO2) – 150.2 lb/day, or NH3 – 709.0 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

In order to ensure that the new combustor complies with various emission limits in the permit, source testing is required to be conducted within 60 days of initial startup. Periodic source testing requirements are kept same as in their existing permit to operate (PTO). The following conditions outline testing requirements:

- Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted within 60 days of initial startup under this permit and at least once every seven years. CEM relative accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with 40 CFR 60, Appendix F (Relative Accuracy Audit). If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NOx and CO testing frequency shall return to the once every seven years schedule. [District Rule 1081]

- Source testing to determine compliance with the NOx, CO, VOC and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 60 days of initial startup under this permit and at least once every 12 months thereafter. [District Rules 2201, 4.0 and 4703, 6.3.1; and 40 CFR 60.4400(a)]

2. Monitoring

No additional monitoring is required. Monitoring requirements from existing permit will be replicated in the ATC under this project.

3. Recordkeeping

No additional recordkeeping is required. Record keeping requirements from existing permit will be replicated in the ATC under this project.

4. Reporting

No additional reporting is required. Reporting requirements from existing permit will be replicated in the ATC under this project.

F. Ambient Air Quality Analysis (AAQA)

Section 4.15 of District Rule 2201 requires that an AAQA be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis.

The proposed location is in an attainment area for NOx, CO, and SOx. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NOx, CO, or SOx.

The proposed location is in a non-attainment area for the state's PM10 as well as federal and state PM2.5 thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM10 and PM2.5.

The AAQA Summary Sheet is included in Appendix H of this document, and summarized in the table below.

Pollutant	Air Quality Standard (State/Federal)				
	1 Hour	3 Hour	8 Hour	24 Hour	Annual
CO	Pass		Pass		
NOx	Pass				N/A
SOx	Pass	Pass		Pass	N/A
PM10				Pass	N/A
PM2.5				Pass	N/A

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII.C.9 above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

This facility is subject to this Rule, and has received their Title V Operating Permit. A significant permit modification is defined as a "permit amendment that does not qualify as a minor permit modification or administrative amendment." In accordance with Rule 2520, Minor Permit Modifications are permit modifications that:

1. Do not violate requirements of any applicable federally enforceable local or federal requirement;

   The proposed project is not expected to violate any federally enforceable local or federal requirements.

2. Do not relax monitoring, reporting, or recordkeeping requirements in the permit and are not significant changes in existing monitoring permit terms or conditions;

   NCPA is not proposing to relax or making any changes to the existing monitoring, reporting, or recordkeeping requirements.

3. Do not require or change a case-by-case determination of an emission limitation or other standard, or a source-specific determination for temporary sources of ambient impacts, or a visibility or increment analysis;

   This project does not require or change any case-by-case determination.

4. Do not seek to establish or change a permit term or condition for which there is no corresponding underlying applicable requirement and that the source has assumed to avoid an applicable requirement to which the source would otherwise be subject. Such terms and conditions include:

   a. A federally enforceable emission cap assumed to avoid classification as a modification under any provisions of title I of the Federal Clean Air Act, prevention of significant deterioration (PSD) provisions of the CAA, or EPA PSD regulations; and

   b. An alternative emissions limit approved pursuant to regulations promulgated under section 112(i)(5) of the Federal Clean Air Act;

   NCPA is not seeking to establish or change existing permit requirement that would exempt them from an applicable requirement.

5. Are not 'Title I modifications' as defined in this rule, modifications as defined in 'section 111 or 112 of the Federal Clean Air Act', or 'major modifications under the prevention of significant deterioration (PSD) provisions of Title I of the CAA or under EPA PSD regulations'

   <u>Title I modifications</u>
   Section 3.31 of Rule 2520 defines "Title I Modification" to be same as defined in District Rule 2201. An older version of District Rule 2201 (4/25/02) defined Title I modification.

Since that time state and federal laws required the District to amend it's Rule 2201 multiple times. These amendments led to the removal of Title I Modification, instead, the District incorporated a separate state and federal provisions - "SB-288 Major Modification" (state based provision) and "Federal Major Modification" (federal regulation (40 CFR 51.165) based provision) in the latest District Rule 2201.

Since Title V permit is a federally mandated operating permit, identifying changes to a Title V permit as "minor" or "significant" are based on results of a "Federal Major Modification". If a project is a "Federal Major Modification" under Rule 2201, then that project is a "major modification" under federal regulations.

As discussed in section VII.C.8 above, the proposed project is not a "Federal Major Modification". Thus, the proposed changes may qualify as a minor modification.

<u>Section 111 or 112 of the Federal Clean Air Act</u>
Section 111, U.S. Code 7411, Standards of performance for new stationary sources[2], section (a)(4) defines "modification" as any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

The proposed project does not result in an increase in amount of any air pollutant on an annual basis. Therefore, the proposed project is not considered modification under this section.

Section 112, U.S. Code 7412, Hazardous air pollutants[3], section (a) defines "modification" as any physical change in, or change in the method of operation of a major source which increases the actual emissions of any hazardous air pollutant emitted by such source by more than a de minimis amount or which results in the emission of any hazardous air pollutant not previously emitted by more than a de minimis amount.

The term "major source" means any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants (HAP).

This facility is not a major source of HAP emissions (refer to **Appendix I** of this document). Since the proposed project will be conducted at a facility that is not a major source of HAPs, this section does not apply.

[2] https://www.govinfo.gov/content/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partA-sec7411.htm
[3] https://www.govinfo.gov/content/pkg/USCODE-2013-title42/html/USCODE-2013-title42-chap85-subchapI-partA-sec7412.htm

<u>Major modifications under the PSD provisions of Title I of the CAA or under EPA PSD regulations</u>

As seen in section VII.C.9 above, the proposed project does not result in emission increase of any pollutant above the PSD significance thresholds. Consequently, the project is not a major modification under the PSD provisions.

6. Do not seek to consolidate overlapping applicable requirements;

   NCPA is not proposing to consolidate any applicable requirements.

This project is a minor modification and, therefore, is not a significant modification.

The facility has applied for a Certificate of Conformity (COC); therefore, the facility must apply to modify their Title V permit with an administrative amendment, prior to operating with the proposed modifications. Continued compliance with this rule is expected. The following conditions will be included on the ATC permit:

- This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201]

- Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4]

Rule 4001 New Source Performance Standards (NSPS)

This rule incorporates NSPS from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60. Applicable subparts are discussed below.

<u>40 CFR Part 60 Subpart GG - Standards of Performance for Stationary Gas Turbines</u>

40 CFR Part 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG.

The proposed turbine is regulated under 40 CFR Part 60 Subpart KKKK. Therefore, it is exempt from the requirements of 40 CFR Part 60 Subpart GG and no further discussion is required.

<u>40 CFR Part 60 Subpart KKKK – Standards of Performance for Stationary Combustion Turbines</u>

The requirements of the 40 CFR Part 60, Subpart KKKK apply to a stationary combustion turbine with heat input (at peak load) equal to or greater than 10 MMBtu/hr, and that commenced construction, modification or reconstruction after February 18, 2005. This subpart regulates nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions only.

The proposed gas turbine is rated at 2,166 MMBtu/hr and will be modified after 2/18/05. Therefore, this turbine is subject to the requirements of this subpart.

Section 60.4320 - Standards for Nitrogen Oxides

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new, modified, or reconstructed turbines firing natural gas with a heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh). This limit is based on 4-hour rolling average or 30-day rolling average as defined in §60.4380(b)(1).

NCPA has proposed to meet 2.0 ppmvd NOx @ 15% O_2 on one-hour rolling average period. NCPA is expected to meet this limit. Permit condition enforcing this requirement is provided under Rule 2201 (DELs).

Section 60.4330 - Standards for Sulfur Dioxide

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or

(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

NCPA has proposed to use PUC-regulated natural gas in the gas turbine with a sulfur content of 1.0 grain/ 100 scf or less. The following condition will ensure compliance with the requirements of this section:

- Gas turbine system shall be fired on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dscf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

NCPA is not proposing to inject water or steam in the CTG. Therefore, the requirements of this section are not applicable.

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §60.4335(b) and 60.4345, or
(2) Continuous parameter monitoring

NCPA has proposed to install a CEMS system as described in §60.4335(b) and 60.4345. The following condition will ensure compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and O_2 concentrations. Continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 2201 and 4703, 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)]

Section 60.4345 – CEMS Equipment Requirements

Paragraph (a) states that each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Paragraph (c) states that each fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flow meters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

NCPA has proposed to install and operate a NO_X CEMS to meet the requirements of this section. NCPA is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. The following conditions will ensure compliance with the requirements of this section:

- The NOx and O_2 CEMS shall be installed and certified in accordance with the requirements of 40 CFR Part 75. The CO CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 4A (PS 4A), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rule 1080, 6.3, 6.5 & 6.6, and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rule 1080, 6.4; and 40 CFR 60.4345(b) and 40 CFR 60.13(e)(2)]

Section 60.4350 – CEMS Data and Excess NO_X Emissions

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

NCPA has proposed to monitor the NO_X emissions rate from the turbine with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_X emissions are released to the atmosphere. The CEMS is expected to be operated in accordance with the methods and procedures described above. The following condition will ensure compliance with the requirements of this section:

- The CEMS data shall be reduced to hourly averages as specified in §60.13(h) and in accordance with §60.4350, or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080, 7.2 and 40 CFR 60.4350(a)(b)(c)(e) & (f)]

Section 60.4355 – Parameter Monitoring Plan

This section set forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, NCPA is proposing to install CEMS that will directly measure NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in no continental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent

(4,000 ppmw) or less for no continental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for no continental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for no continental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for non-continental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

NCPA has proposed to use PUC regulated natural gas that may contain up to 1.0 grain-S/100 scf. Primarily, the natural gas suppliers are able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with this natural gas sulfur content limit. If the sulfur content information is not available from the gas supplier, then the permittee is required to test fuel sulfur content on weekly basis. Upon successful compliance demonstration on 8 week consecutive tests, the test frequency shall be reduced to every six months. If any six-month test shows non-compliance with the sulfur content requirement, weekly testing will resume until eight consecutive weeks show compliance.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil:* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel:* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules:* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract, or (ii) monitored within 60 days after the end of commissioning period and weekly thereafter. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions and Monitor Downtime

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, NCPA is not proposing to monitor parameters associated with water or steam to fuel ratios to predict NO_X emissions. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

    NCPA has proposed to emit less than or equal to 2.0 ppmvd NOx @ 15% O_2, 15.54 lb-NOx/hr on 1-hour rolling average period. Emissions excess of these standards will constitute a violation of the permitted limits. These emissions standards and the averaging period are more stringent that of the ones listed above in section 40 CFR 60.4380(b)(1). Therefore, compliance with this section will be assured by complying with the permitted limit.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO_2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes. The following permit condition is placed to assure compliance with this section.

- Monitor Downtime is defined as any unit operating hour in which the data for NOx, or O_2 concentrations is either missing or invalid. [40 CFR 60.4380(b)(2)]

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_X emission controls. NCPA is not proposing to monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Section 60.4385 – Excess SO_X Emissions and Monitoring Downtime

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

NCPA is expected to follow the definitions and procedures specified above for determining periods of excess SO_X emissions. Compliance is expected with this section.

Sections 60.4375 and 60.4395 – Reports Submittal

Section 60.4375(a) states that for each affected unit required to continuously monitor parameters or emissions, or to periodically determine the fuel sulfur content under this subpart, you must submit reports of excess emissions and monitor downtime, in accordance with §60.7(c). Excess emissions must be reported for all periods of unit operation, including start-up, shutdown, and malfunction.

Section 60.4375(b) states that for each affected unit that performs annual performance tests in accordance with §60.4340(a), you must submit a written report of the results of each performance test before the close of business on the 60th day following the completion of the performance test.

Section 60.4395 states All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

NCPA is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. The following condition will ensure compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEMS operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Date, time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Subsequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set fourth the requirements for the methods that are to be used during source testing.

NCPA will be required to source test before the end of the commissioning period (i.e. 90 days of initial startup) and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). The following conditions will ensure compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO, VOC and NH3 emission rates (lb/hr and ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted within 60 days of initial startup under this permit and at least once every 12 months thereafter. [District Rules 2201, 4.0 and 4703, 6.3.1; and 40 CFR 60.4400(a)]

- The following test methods shall be used: NO_X - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 -

EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 5.0 and 4703, 6.3.1, 6.4.1 thru 6.4.3; and 40 CFR 60.4400(a)(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). NCPA has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, NCPA is proposing to install a CEMS system to monitor the NO_X emissions for the turbine and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– SO_X Performance Testing

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

NCPA is expected to periodically determine the sulfur content of the fuel combusted in the turbine when valid purchase contracts, tariff sheets or transportation contract are not available.

The sulfur content will be determined using the methods specified above. The following condition will ensure compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. NCPA is not proposing to measure the SO_2 in the exhaust stream of the turbine. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Compliance is expected with this Subpart.

Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

This rule incorporates NESHAPs from Part 61, Chapter I, Subchapter C, Title 40, CFR and the NESHAPs from Part 63, Chapter I, Subchapter C, Title 40, CFR; and applies to all sources of hazardous air pollution listed in 40 CFR Part 61 or 40 CFR Part 63.

40 CFR Part 63 Subpart YYYY – National Emission Standards for Hazardous Air Pollutants for Stationary Gas Turbines

The requirements of the 40 CFR Part 63, Subpart YYYY apply to a stationary combustion turbines located at major sources of HAP emissions. This stationary source is not a major source of HAP emissions (see Appendix I). Therefore, this subpart is not applicable.

Rule 4101 Visible Emissions

Rule 4101 states that no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity). As the turbine is fired solely on natural gas, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity. Also, based on past inspections of the facility continued compliance is expected.

Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification of an existing source shall not result in an increase in cancer risk greater than the District's significance level (20 in a million) and shall not result in acute and/or chronic risk indices greater than 1.

An HRA is not required for a project with a total facility prioritization score of less than or equal to one. According to the Technical Services Memo for this project, the total facility prioritization score including this project was less than or equal to one.

The resulting prioritization score for this project is shown below.

Health Risk Assessment Summary	
	Worst Case Potential
Prioritization Score	0.43

In accordance with District policy APR 1905, no further analysis is required to determine the impact from this project and compliance with the District's Risk Management Policy is expected.

Compliance with District Rule 4102 requirements is expected.

See Appendix H: Health Risk Assessment Summary

The following permit conditions are required to ensure compliance with the assumptions made for the risk management review:

- The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or other obstruction. [District Rule 4102]

Rule 4201 Particulate Matter Concentration

Section 3.0 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot. As

At the heat input rate of 2,166 MMBtu/hr, the exhaust flow rate can be estimated to be 18,865,860 dscf/hr (calculated with F-factor for natural gas of 8,710 dscf/MMBtu). The maximum allowed PM10 emission rate is 9 lb/hr (63,000 gr/hr). Therefore, the maximum expected concentration is 0.003 gr/hr. Since 0.003 gr/dscf is less than 0.1 gr/dscf, compliance is expected with this rule.

Rule 4301 Fuel Burning Equipment

The provisions of this rule shall apply to any fuel burning equipment except air pollution control equipment which is exempted according to Section 4.0. Fuel burning equipment is defined as any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer.

The requirements of section 5.0 are as follows:

- Combustion contaminates (TSP) - Not to exceed 0.1 gr/dscf @ 12% CO_2 and 10 lb/hr.
- SO_x emissions - Not to exceed 200 lb/hr
- NO_x emissions - Not to exceed 140 lb/hr

Combustion turbine generators primarily produce power mechanically, i.e. the products of combustion pass directly across the turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft, which rotates and produces electricity. Because the CTG primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment (stated above). Therefore, Rule 4301 does not apply to the affected equipment and no further discussion is required.

Rule 4703 Stationary Gas Turbines

Applicability

Section 2.0 of this rule states that the provisions of this rule apply to all stationary gas turbine systems, which are subject to District permitting requirements, and with ratings equal to or greater than 0.3 megawatt (MW) or a maximum heat input rating of more than 3,000,000 Btu per hour, except as provided in Section 4.0.

The proposed CTG will have a heat input rate of 2,166 MMBtu per hour. Therefore, the proposed system is subject to the requirements of this rule.

Section 5.1 – NO_X Emission Requirements

Section 5.1.2 (Tier 2) of this rule limits the NO_X emissions from combined cycle, stationary gas turbine system rated at greater than 10 MW to 5 ppmv @ 15% O_2 (Standard Option) and 3 ppmv @ 15% O_2 (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbine system will be limited to 2.0 ppmv @ 15% O_2 (based on a 1-hour average); therefore compliance with this section is expected. The following conditions will be placed on the permit:

- Except during startup, shutdown and combustor tuning periods, emissions from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) - 15.96 lb/hr and 2.0 ppmvd @ 15% O2; CO - 9.72 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.89 lb/hr and 1.4 ppmvd @ 15% O2; PM10 - 9.0 lb/hr; or SOx (as SO2) - 6.26 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001, and 4703]

Section 5.2 – CO Emission Requirements

Per Table 5-4 of section 5.2, the CO emissions concentration from the proposed gas turbine system must be less than 25 ppmvd @ 15% O_2. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. The District practice is to require CO emissions compliance demonstration on 3-hour rolling average period.

NCPA has proposed to emit less than or equal to 2 ppmvd CO @ 15% O_2 on 3-hour rolling average period. Thus, compliance is expected with this section. Refer to the conditions shown in Section 5.1.2 (above).

Section 5.3 – Transitional Operation Periods

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during a transitional operation period, which includes bypass transition period, primary re-ignition period, reduced load period, start-up or shutdown (each term is defined in Section 3.0 of Rule 4703), provided an operator complies with the requirements of section 5.3.1 which are outlined below:

5.3.1.1 The duration of each startup or each shutdown shall not exceed two hours.
5.3.1.2 For each bypass transition period, the requirements specified in Section 3.2 shall be met.
5.3.1.3 For each primary re-ignition period, the requirements specified in Section 3.20 shall be met.
5.3.1.4 Each reduced load period shall not exceed one hour.

NCPA has proposed to incorporate startup and shutdown provisions into the operating requirements for the proposed gas turbine system which limit startup or shutdown times to 100 minutes. This limitation satisfies the requirement of 5.3.1.1. The following condition limiting startup/shutdown time will be included on the permit.

- The start-up time shall not exceed 100 minutes for each event during any startup mode (i.e., hot start < 16 hour downtime, warm start - 16 to 64 hour downtime, or cold start > 64 hour downtime). The shutdown time shall not exceed 100 minutes for each event. [District Rules 2201, 4.0 and 4703, 5.3]

Section 5.3.1.2 requires the operator to meet the requirements of Section 3.2 for each bypass transition period. Per NCPA's consultant, the exhaust from the CTG is vented into the HRSG. There is no bypass exhaust stack. Therefore, this turbine system is not required to meet any bypass transition period requirements.

Section 5.3.1.3 requires the permittee to meet the requirements in Section 3.20 for each primary re-ignition period. Section 3.20 defines the primary re-ignition period and requires the following:

- The duration of a primary re-ignition shall not exceed one hour
- NOx emissions shall not exceed 15 ppmvd @ 15% O_2, average over one-hour

- CO emissions shall not exceed 25 ppmvd @ 15% O_2

Per NCPA's consultant, the DLN combustor system that will be used for this project is designed so that it would not require re-ignition as defined in this rule. A failure of the Frame 7 DLN combustor system would result in a turbine shutdown. Therefore, no condition related to primary re-ignition will be listed on the permit.

Section 5.3.1.4 requires that each reduced load period shall not exceed one hour. Reduced load period is defined as the time during which a gas turbine is operated at less than rated capacity in order to change the position of the exhaust gas diverter gate. Per NCPA, the LEC gas turbine will not be equipped with an exhaust gas diverter gate. Therefore, no condition related to "reduced load period" is needed in the permit.

Section 5.3.2 requires that emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during each transitional period (in this case it would be startup, shutdown, reduced load period and primary re-ignition period). The following condition will be listed on the permit:

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rules 2201, 4.0 and 4703, 5.3.2]

Section 5.3.3 specifies criteria by which approval may be granted for transitional operation periods in excess of the durations specified in Section 5.3.1. NCPA has proposed satisfaction of the requirements of Section 5.3.1. Therefore, this section does not apply.

<u>Section 6.2 - Monitoring and Recordkeeping</u>

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for NO_X and oxygen, or install and maintain APCO-approved alternate monitoring. As discussed earlier in this evaluation, NCPA has proposed to operate a Continuous Emissions Monitoring System (CEMS) that will monitors NO_X and oxygen content in the exhaust stack. Therefore, the requirements of this section have been satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and O_2 concentrations. Continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 4.0 & 5.0; 2201, 4.0 and 4703, 6.2.1; 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)]]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. The proposed gas turbine system will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbine was not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. NCPA will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbines will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will placed on the permit:

- The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 2201 and 4703, 6.2.4]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_X output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_X available or when the continuous emissions monitoring system is not operating properly. The following condition will be placed on the permit:

- The owner or operator shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit when the CEMS is not operating properly. [District Rule 4703, 6.2.5]

Section 6.2.6 requires the owner or operator to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used.

Section 6.2.7 requires the owner or operator shall maintain a stationary gas turbine system log for units exempt under Section 4.2 of this Rule. NCPA's gas turbine system is not exempt under Section 4.2 of this Rule. Therefore, no further discussion is required.

Section 6.2.8 requires the operator performing start-up or shutdown of a unit shall keep records of the duration of start-up or shutdown.

Section 6.2.11 requires the operator of a unit shall keep records of the date, time and duration of each bypass transition period and each primary re-ignition period. As discussed above, the project will not utilize bypass transition or primary re-ignition.

NCPA will be required to maintain records of the items listed in above applicable sections. The following conditions will be placed on the permit:

- The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, the type and quantity of fuel used, duration of start-up, duration of shutdown, and duration of each combustor tuning event. [District Rule 4703, 6.26, 6.28, 6.2.11]

Sections 6.3 and 6.4 - Compliance Testing

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO_X and CO concentrations. The gas turbine system proposed by NCPA is subject to the provisions of Section 5.0 of this rule. Therefore, this system is required to be tested annually to ensure compliance with NO_X and CO concentrations. The following condition will be placed on the permit:

- Source testing to determine compliance with the NOx, CO, VOC and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 60 days of initial startup under this permit and at least once every 12 months thereafter. [District Rules 2201 and 4703, 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbine system will be allowed to operate in excess of 877 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 states that units with intermittently operated auxiliary burners shall demonstrate compliance with the auxiliary burner in both “on” and “off” configurations. This rule defines auxilary burner as any fuel burning device that increases the heat content of the exhaust gas from a gas turbine. The plant will not utilize auxiliary burners, so this section is not applicable.

Section 6.4 states that the facility must demonstrate compliance annually with the NO_X and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.

- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.

- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: NO_X - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Compliance is expected with this Rule.

Rule 4801 Sulfur Compounds

Section 3.1 states that a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding a concentration of two-tenths (0.2) percent by volume calculated as sulfur dioxide (SO_2) at the point of discharge on a dry basis averaged over 15 consecutive minutes.

For the proposed gaseous fuel combustion at a reference state of 60 °F, the Rule 4801 limit of 2,000 ppmvd is equivalent to:

$$\frac{(2000\ \text{ppmvd})\left(8{,}578\ \frac{\text{dscf}}{\text{MMBtu}}\right)\left(64\ \frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)}{\left(379.5\ \frac{\text{dscf}}{\text{lb}-\text{mol}}\right)(10^6)} \cong 2.9\ \frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

SO_x emissions from proposed CTG is based on fuel sulfur content of 1.0 gr-S/100 scf, equivalent to 0.00285 lb/MMBtu. Since these emissions are less than 2.9 lb/MMBtu, it is expected that each unit will operate in compliance with this Rule.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

The California Energy Commission (CEC) is the public agency having principal responsibility for approving the turbine upgrade to ultra low NOx combustion project (Project) for the Lodi Energy Center (08-AFC-10C), which covers this ATC project. The CEC has the exclusive power to certify all thermal electric power plants greater than 50 MW in the State of California (Public

Resources Code § 25500). While the CEC siting process is exempt from CEQA (14 CCR § 15251(j)), it is functionally equivalent to CEQA.

The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). The District prepared an engineering evaluation (this document) with a Determination of Compliance conferring the rights and privileges of an Authority to Construct upon certification by the CEC, where the CEC certificate contains the conditions set forth in this engineering evaluation (20 CCR § 1744.5 and Rule 2201 § 5.8.8).

Indemnification Agreement / Letter of Credit Determination

The criteria pollutant emissions and toxic air contaminant emissions associated with the proposed project are not significant, and there is minimal potential for public concern for this particular type of facility/operation. Therefore, an IA and/or an LOC will not be required for this project.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. The ATC N-2697-5-9 (draft conditions in Appendix A) should be issued after addressing any comments from the public, CARB, EPA, and NCPA**.**

X. Billing Information

Annual Permit Fees			
Permit Number	**Fee Schedule**	**Fee Description**	**Annual Fee**
N-2697-5-9	3020-08-I	311,000 kW	$26,889

XI. Appendices

A: Draft Permit Requirements
B: Current PTO
C: Actual Emission Data – Jan 2019 through May 2024
D: Projected Actual Emissions
E: Project Emissions Increase Calculations
F: Quarterly Net Emissions Change
G: Top Down BACT Analysis
H: HRA/AAQA Summary
I: HAP Calculations

APPENDIX A
Draft Permit Requirements

1. {1830} This Authority to Construct serves as a written certificate of conformity with the procedural requirements of 40 CFR 70.7 and 70.8 and with the compliance requirements of 40 CFR 70.6(c). [District Rule 2201] Y

2. {1831} Prior to operating with modifications authorized by this Authority to Construct, the facility shall submit an application to modify the Title V permit with an administrative amendment in accordance with District Rule 2520 Section 5.3.4. [District Rule 2520, 5.3.4] Y

3. Particulate matter emissions from the gas turbine system shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Y

4. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper OK), roof overhang, or other obstruction. [District Rule 4102] N

5. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080, 11.0] Y

6. The start-up time shall not exceed 100 minutes for each event during any startup mode (i.e., hot start < 16 hour downtime, warm start - 16 to 64 hour downtime, or cold start > 64 hour downtime). The shutdown time shall not exceed 100 minutes for each event. [District Rules 2201, 4.0 and 4703, 5.3] Y

7. During all types of operation, including startup (cold, warm and hot), shutdown, and combustor tuning periods, ammonia injection into the SCR system shall occur once the minimum temperature of 406øF at the catalyst face has been reached to ensure NOx emission reductions can occur with a reasonable level of ammonia slip. The District may administratively modify the temperature as necessary following any replacement of the SCR catalyst material. [District Rule 2201, 4.0] Y

8. The SCR system shall be equipped with a continuous temperature monitoring system to measure and record the temperature at the catalyst face. [District Rule 2201, 4.0] Y

9. The oxidation catalyst shall be equipped with a continuous temperature monitoring system to measure and record the temperature at the inlet face of the oxidation catalyst. [40 CFR Part 64] Y

10. The oxidation catalyst shall be maintained between 450øF and 1,350øF except during startup, shutdown, and combustor tuning periods. Upon detecting any excursion, the permittee shall investigate the excursion and take corrective action to minimize excessive emissions and prevent recurrence of the excursion as expeditiously as practicable. The District may administratively re-establish temperature range as necessary following any replacement of the oxidation catalyst material. [40 CFR Part 64] Y

11. The owner or operator shall measure and record temperature at the inlet face of the oxidation catalyst during each source test while measuring VOC emissions. [40 CFR Part 64] Y

12. During start-up, and shutdown and combustor tuning periods, the emissions shall not exceed any of the following limits: NOx (as NO2) - 160.00 lb/hr; CO - 1,500.00 lb/hr; VOC (as methane) - 16.00 lb/hr; PM10 - 9.00 lb/hr; SOx (as SO2) - 6.26 lb/hr; or NH3 - 29.54 lb/hr. [District Rule 2201] N

13. Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. [District Rule 4703, 3.29] Y

14. Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status ending when the fuel supply to the unit is completely turned off. [District Rule 4703, 3.26] Y

15. Combustor tuning periods are any periods, not to exceed 8 hours in any calendar day or 40 hours in any calendar year, when combustor tuning activities are taking place. Combustor tuning activities are defined as any testing, adjustment, tuning, and calibration activities recommended by the gas turbine manufacturer to ensure safe and reliable steady-state operation of the gas turbine following replacement of the combustor components, during seasonal tuning events, or at other times when recommended by the turbine manufacturer or necessary to maintain low emissions performance. This includes, but is not limited to, adjusting the amount of fuel distributed between the combustion turbine's staged fuel systems to simultaneously minimize NOx and CO production while minimizing combustor dynamics and ensuring combustor stability. [District Rule 2201, 4.0] Y

16. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown and combustor tuning periods. [District Rules 2201, 4.0 and 4703, 5.3.2] Y

17. Except during startup, shutdown and combustor tuning periods, emissions from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) - 15.96 lb/hr and 2.0 ppmvd @ 15% O2; CO - 9.72 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.89 lb/hr and 1.4 ppmvd @ 15% O2; PM10 - 9.0 lb/hr; or SOx (as SO2) - 6.26 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4001, and 4703] Y

18. NH3 emissions shall not exceed any of the following limits: 10.0 ppmvd @ 15% O2 over a 24-hour rolling average period and 29.54 lb/hr. [District Rule 2201] Y

19. Each 3-hour rolling average period will be compiled from the three most recent one hour periods. Each one hour period shall commence on the hour. Each one hour period in a twenty-four hour rolling average for ammonia slip will commence on the hour. The twenty-four hour rolling average shall be calculated using the most recent twenty-four one-hour periods. [District Rule 2201, 4.0] Y

20. Emissions from the gas turbine system, on days when startup, shutdown and/or combustor tuning activities occur, shall not exceed the following limits: NOx (as NO2) - 879.7 lb/day; CO - 5,570.3 lb/day; VOC - 164.2 lb/day; PM10 - 216.0 lb/day; SOx (as SO2) - 150.2 lb/day, or NH3 - 709.0 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201] Y

21. Emissions from the gas turbine system, on days when startup, shutdown and/or combustor tuning activities do not occur, shall not exceed the following: NOx (as NO2) - 383.0 lb/day; CO - 233.3 lb/day; VOC - 93.4 lb/day; PM10 - 216.0 lb/day; SOx (as SO2) - 150.4 lb/day, or NH3 - 709.0 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201] Y

22. Gas turbine system shall be fired on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dscf of natural gas. [District Rule 2201, 4.0 and 40 CFR 60.4330(a)(2)] Y

23. NOx (as NO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 38,038 lb; 2nd quarter: 38,411 lb; 3rd quarter: 37,126 lb; 4th quarter: 37,840 lb. [District Rule 2201, 4.0] Y

24. CO emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 142,312 lb; 2nd quarter: 142,539 lb; 3rd quarter: 86,374 lb; 4th quarter: 113,660 lb. [District Rule 2201, 4.0] Y

25. VOC emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 8,086 lb; 2nd quarter: 8,177 lb; 3rd quarter: 8,417 lb; 4th quarter: 8,323 lb. [District Rule 2201, 4.0] Y

26. NH3 emissions from the SCR system shall not exceed any of the following: 1st quarter: 62,122 lb; 2nd quarter: 62,812 lb; 3rd quarter: 63,502 lb; 4th quarter: 63,502 lb. [District Rule 2201, 4.0] Y

27. PM10 emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 19,440 lb; 2nd quarter: 19,656 lb; 3rd quarter: 19,872 lb; 4th quarter: 19,872 lb. [District Rule 2201, 4.0] Y

28. SOx (as SO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 13,176 lb; 2nd quarter: 13,322 lb; 3rd quarter: 13,469 lb; 4th quarter: 13,469 lb. [District Rule 2201, 4.0] Y

29. The total CO emissions from the gas turbine system (N-2697-5) and the auxiliary boiler (N-2697-7) shall not exceed 198,000 pounds in any 12-consecutive month rolling period. [District Rule 2201, 4.0] Y

30. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine system. [District Rule 2201, 4.0] Y

31. The gas turbine engine and generator lube oil vents shall be equipped with mist eliminators or equivalent technology sufficient to limit the visible emissions from the lube oil vents to not exceed 5% opacity, except for a period not exceeding three minutes in any one hour. [District Rule 2201, 4.0] Y

32. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081, 7.1] Y

33. Source testing shall be witnessed or authorized by District personnel and samples shall be collected by a California Air Resources Board (CARB) certified testing laboratory or a CARB certified source testing firm. [District Rule 1081, 7.2] Y

34. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted within 60 days of initial startup under this permit and at least once every seven years. CEM relative accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with 40 CFR 60, Appendix F (Relative Accuracy Audit). If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NOx and CO testing frequency shall return to the once every seven years schedule. [District Rule 1081] Y

35. Source testing to determine compliance with the NOx, CO, VOC and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted within 60 days of initial startup under this permit and at least once every 12 months thereafter. [District Rules 2201, 4.0 and 4703, 6.3.1; and 40 CFR 60.4400(a)] Y

36. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract, or (ii) monitored weekly. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 2201, 4.0; and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)] Y

37. The following test methods shall be used: NOx - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201a and 202; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 5.0 and 4703, 6.3.1, 6.4.1 through 6.4.3; and 40 CFR 60.4400(a)(1)(i)] Y

38. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)] Y

39. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081, 7.2 & 7.3] Y

40. A mass or volumetric fuel flow meter that meets the requirements of 40 CFR Part 75 shall be installed, utilized and maintained to measure the amount of natural gas combusted in the unit. [District Rules 2201, 4.0 and 4703] Y

41. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and O2 concentrations. Continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 4.0 & 5.0; 2201, 4.0 and 4703, 6.2.1; 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)] Y

42. The NOx and O2 CEMS shall be installed and certified in accordance with the requirements of 40 CFR Part 75. The CO CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 4A (PS 4A), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rule 1080, 6.3, 6.5 & 6.6, and 40 CFR 60.4345(a)] Y

43. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rule 1080, 6.4; and 40 CFR 60.4345(b) and 40 CFR 60.13(e)(2)] Y

44. The CEMS data shall be reduced to hourly averages as specified in 40 CFR 60.13(h) and in accordance with 40 CFR 60.4350, or by other methods deemed equivalent by

mutual agreement with the District, the CARB, and the EPA. [District Rule 1080, 7.2 and 40 CFR 60.4350(a)(b)(c)(e) & (f)] Y

45. In accordance with 40 CFR Part 60, Appendix F, 5.1, the CO CEMS must be audited at least once each calendar quarter, by conducting cylinder gas audits (CGA) or relative accuracy audits (RAA). CGA or RAA may be conducted three of four calendar quarters, but no more than three calendar quarters in succession. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080, 8.0 and 40 CFR Part 60 Appendix F, 5.1.2] Y

46. The owner/operator shall perform a RATA for CO as specified by 40 CFR Part 60, Appendix F, 5.1.1, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080, 8.0 and 40 CFR Part 60 App. F, 5.1.1] Y

47. The NOx and O2 CEMS shall be audited in accordance with the applicable requirements of 40 CFR Part 75. Linearity reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080] Y

48. Upon written notice from the District, the owner or operator shall provide a summary of the data obtained from the CEMS. This summary shall be in the form and the manner prescribed by the District. [District Rule 1080, 7.1] Y

49. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEMS data polling software system and shall make CEMS data available to the District's automated polling system on a daily basis. Upon notice by the District that the facility's CEMS is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEMS data is sent to the District by a District-approved alternative method. [District Rule 1080, 7.1] Y

50. The owner or operator shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080, 7.3 and 2201, 4.0; and 40 CFR 60.7(b)] Y

51. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance

Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081] Y

52. Monitor Downtime is defined as any unit operating hour in which the data for NOx, O2 concentrations is either missing or invalid. [40 CFR 60.4380(b)(2)] Y

53. The owner or operator shall maintain records of the following items on the combustor tuning activities: (1) date on which combustor tuning activity occurs, (2) description of each combustor tuning activity, (3) reason why each combustor tuning activity is required, (4) documentation (such as operating manuals, letters, e-mails, etc.) showing that each combustor tuning activity is necessary. [District Rule 2201, 4.0] Y

54. The owner or operator shall maintain records of the following items: (1) hourly and daily emissions, in pounds, for each pollutant listed in this permit on the days startup, shutdown and/or combustor tuning activities of the gas turbine system occur, (2) hourly and daily emissions, in pounds, for each pollutant in this permit on the days startup, shutdown and/or combustor tuning activities of the gas turbine system do not occur, (3) quarterly emissions, in pounds, for each pollutant listed in this permit, and (4) the combined CO emissions (12 consecutive month rolling total) , in pounds, for permit unit N-2697-5 and N-2697-7. [District Rule 2201, 4.0] Y

55. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, total hours of operation, the type and quantity of fuel used, mode of start-up (cold, warm, or hot), duration of each start-up, duration of each shutdown, and duration of each combustor tuning event. [District Rules 2201, 4.0 and 4703, 6.26, 6.28, 6.2.11] Y

56. The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 2201, 4.0 and 4703, 6.2.4; 40 CFR 60.7(f)] Y

57. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Date, time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080, 8.0; 40 CFR 60.4375(a) and 40 CFR 60.4395] Y

58. The owner or operator shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx

emission limits of this permit when the CEMS is not operating properly. [District Rule 4703, 6.2.5] Y

59. The owners and operators of each affected source and each affected unit at the source shall have an Acid Rain permit and operate in compliance with all permit requirements. [40 CFR 72.9(a)(2)] Y

60. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75. [40 CFR 75] Y

61. The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75.1] Y

62. The owners and operators of each source and each affected unit at the source shall: (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73 and 40 CFR 72.9(c)(1)] Y

63. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77] Y

64. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72.9(c)(4)] Y

65. An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73.35 and 40 CFR 72.9(c)(5)] Y

66. An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72] Y

67. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72.2] Y

68. The designated representative of an affected unit that has excess emissions of sulfur dioxide in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77. [40 CFR 77.3 and 40 CFR 72.9(e)(1)] Y

69. The owners and operators of an affected unit that has excess emissions of sulfur dioxide or nitrogen oxides in any calendar year shall: (i) Pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77.4(k); 40 CFR 77.6; and 40 CFR 72.9(e)(2)] Y

70. The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72.9(f)(1)(i) and 40 CFR 72.9(f)(1)(ii-iv)] Y

71. The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 75.3(c) and 40 CFR 72.9(f)(2)] Y

72. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75] Y

73. If the emission unit's actual NOx, SOx, CO, PM, PM10 (all PM can be assumed to be equal to PM10), or VOC emissions exceed the actual emissions projected under project N-1243995 on a calendar year basis, the permittee must report to the District the annual emissions as calculated pursuant to paragraph 40 CFR 51.165(a)(6)(iii) or 40 CFR 52.21(r)(6)(iii) and any other information that the owner or operator wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection). Such information must be submitted to the District for a period of 10 calendar years beginning the year of operation under ATC N-2697-5-9 and shall be submitted within 60 days of the end of each calendar year. [District Rules 2201 and 2410] N

APPENDIX B
Current PTO

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: N-2697-5-8 **EXPIRATION DATE:** 05/31/2029

EQUIPMENT DESCRIPTION:
294 MW (NOMINAL) COMBINED-CYCLE ELECTRIC GENERATION PLANT CONSISTING OF A SIEMENS INDUSTRIAL FRAME "FLEX PLANT 30" STG6-5000F NATURAL GAS-FIRED TURBINE ENGINE WITH ADVANCED ULTRA LOW-NOX COMBUSTOR SYSTEM, AN UNFIRED HEAT RECOVERY STEAM GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION WITH AMMONIA INJECTION AND AN OXIDIZATION CATALYST AND A STEAM TURBINE GENERATOR

PERMIT UNIT REQUIREMENTS

1. Particulate matter emissions from the gas turbine system shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201] Federally Enforceable Through Title V Permit
2. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080, 11.0] Federally Enforceable Through Title V Permit
3. The start-up time shall not exceed 100 minutes for each event during any startup mode (i.e., hot start < 16 hour downtime, warm start - 16 to 64 hour downtime, or cold start > 64 hour downtime). [District Rules 2201, 4.0 and 4703, 5.3.3] Federally Enforceable Through Title V Permit
4. During all types of operation, including startup (cold, warm and hot), shutdown, and combustor tuning periods, ammonia injection into the SCR system shall occur once the minimum temperature of 406°F at the catalyst face has been reached to ensure NOx emission reductions can occur with a reasonable level of ammonia slip. The District may administratively modify the temperature as necessary following any replacement of the SCR catalyst material. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit
5. The SCR system shall be equipped with a continuous temperature monitoring system to measure and record the temperature at the catalyst face. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit
6. The oxidation catalyst shall be equipped with a continuous temperature monitoring system to measure and record the temperature at the inlet face of the oxidation catalyst. [40 CFR Part 64] Federally Enforceable Through Title V Permit
7. The oxidation catalyst shall be maintained between 450°F and 1,350°F except during startup, shutdown, and combustor tuning periods. Upon detecting any excursion, the permittee shall investigate the excursion and take corrective action to minimize excessive emissions and prevent recurrence of the excursion as expeditiously as practicable. The District may administratively re-establish temperature range as necessary following any replacement of the oxidation catalyst material. [40 CFR Part 64] Federally Enforceable Through Title V Permit
8. The owner or operator shall measure and record temperature at the inlet face of the oxidation catalyst during each source test while measuring VOC emissions. [40 CFR Part 64] Federally Enforceable Through Title V Permit
9. During start-up, and shutdown and combustor tuning periods, the emissions shall not exceed any of the following limits: NOx (as NO_2) - 160.00 lb/hr; CO - 1,500.00 lb/hr; VOC (as methane) - 16.00 lb/hr; PM10 - 9.00 lb/hr; SOx (as SO_2) - 6.10 lb/hr; or NH_3 - 28.76 lb/hr. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit
10. Start-up is defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operation. [District Rule 4703, 3.29] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

These terms and conditions are part of the Facility-wide Permit to Operate.

Facility Name: NORTHERN CALIFORNIA POWER
Location: 12745 N THORNTON RD,LODI, CA 95242
N-2697-5-8 : Aug 12 2024 11:31AM – ROBINSOM

11. Shutdown is defined as the period of time during which a unit is taken from an operational to a non-operational status ending when the fuel supply to the unit is completely turned off. [District Rule 4703, 3.26] Federally Enforceable Through Title V Permit

12. Combustor tuning periods are any periods, not to exceed 8 hours in any calendar day or 40 hours in any calendar year, when combustor tuning activities are taking place. Combustor tuning activities are defined as any testing, adjustment, tuning, and calibration activities recommended by the gas turbine manufacturer to ensure safe and reliable steady-state operation of the gas turbine following replacement of the combustor components, during seasonal tuning events, or at other times when recommended by the turbine manufacturer or necessary to maintain low emissions performance. This includes, but is not limited to, adjusting the amount of fuel distributed between the combustion turbine's staged fuel systems to simultaneously minimize NOx and CO production while minimizing combustor dynamics and ensuring combustor stability. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit

13. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown and combustor tuning periods. [District Rules 2201, 4.0 and 4703, 5.3.2] Federally Enforceable Through Title V Permit

14. Except during startup, shutdown and combustor tuning periods, emissions from the gas turbine system shall not exceed any of the following limits: NOx (as NO2) - 15.54 lb/hr and 2.0 ppmvd @ 15% O2; CO - 9.46 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.79 lb/hr and 1.4 ppmvd @ 15% O2; PM10 - 9.0 lb/hr; or SOx (as SO2) - 6.10 lb/hr. NOx (as NO2) emission limits are based on 1-hour rolling average period. All other emission limits are based on 3-hour rolling average period. [District Rules 2201, 4.0; 4001; and 4703, 4.1.2 and 5.2] Federally Enforceable Through Title V Permit

15. NH3 emissions shall not exceed any of the following limits: 10.0 ppmvd @ 15% O2 over a 24-hour rolling average period and 28.76 lb/hr. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit

16. Each 3-hour rolling average period will be compiled from the three most recent one hour periods. Each one hour period shall commence on the hour. Each one hour period in a twenty-four hour rolling average for ammonia slip will commence on the hour. The twenty-four hour rolling average shall be calculated using the most recent twenty-four one-hour periods. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit

17. Emissions from the gas turbine system, on days when startup, shutdown and/or combustor tuning activities occur, shall not exceed the following limits: NOx (as NO2) - 879.7 lb/day; CO - 5,570.3 lb/day; VOC - 164.2 lb/day; PM10 - 216.0 lb/day; SOx (as SO2) - 146.4 lb/day, or NH3 - 690.3 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit

18. Emissions from the gas turbine system, on days when startup, shutdown and/or combustor tuning activities do not occur, shall not exceed the following: NOx (as NO2) - 373.0 lb/day; CO - 227.0 lb/day; VOC - 91.0 lb/day; PM10 - 216.0 lb/day; SOx (as SO2) - 146.4 lb/day, or NH3 - 690.3 lb/day. Daily emissions shall be compiled for a twenty-four hour period starting and ending at twelve-midnight. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit

19. Gas turbine system shall be fired on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grain of sulfur compounds (as S) per 100 dscf of natural gas. [District Rule 2201, 4.0 and 40 CFR 60.4330(a)(2)] Federally Enforceable Through Title V Permit

20. NOx (as NO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 38,038 lb; 2nd quarter: 38,411 lb; 3rd quarter: 37,126 lb; 4th quarter: 37,840 lb. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit

21. CO emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 142,312 lb; 2nd quarter: 142,539 lb; 3rd quarter: 86,374 lb; 4th quarter: 113,660 lb. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit

22. VOC emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 8,086 lb; 2nd quarter: 8,177 lb; 3rd quarter: 8,417 lb; 4th quarter: 8,323 lb. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

23. NH3 emissions from the SCR system shall not exceed any of the following: 1st quarter: 62,122 lb; 2nd quarter: 62,812 lb; 3rd quarter: 63,502 lb; 4th quarter: 63,502 lb. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit
24. PM10 emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 19,440 lb; 2nd quarter: 19,656 lb; 3rd quarter: 19,872 lb; 4th quarter: 19,872 lb. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit
25. SOx (as SO2) emissions from the gas turbine system shall not exceed any of the following: 1st quarter: 13,176 lb; 2nd quarter: 13,322 lb; 3rd quarter: 13,469 lb; 4th quarter: 13,469 lb. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit
26. The total CO emissions from the gas turbine system (N-2697-5) and the auxiliary boiler (N-2697-7) shall not exceed 198,000 pounds in any 12-consecutive month rolling period. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit
27. A selective catalytic reduction (SCR) system and an oxidation catalyst shall serve the gas turbine system. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit
28. The gas turbine engine and generator lube oil vents shall be equipped with mist eliminators or equivalent technology sufficient to limit the visible emissions from the lube oil vents to not exceed 5% opacity, except for a period not exceeding three minutes in any one hour. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit
29. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081, 7.1] Federally Enforceable Through Title V Permit
30. Source testing shall be witnessed or authorized by District personnel and samples shall be collected by a California Air Resources Board (CARB) certified testing laboratory or a CARB certified source testing firm. [District Rule 1081, 7.2] Federally Enforceable Through Title V Permit
31. Source testing to measure startup and shutdown NOx, CO, and VOC mass emission rates shall be conducted at least once every seven years. CEM relative accuracy for NOx and CO shall be determined during startup and shutdown source testing in accordance with 40 CFR 60, Appendix F (Relative Accuracy Audit). If CEM data is not certifiable to determine compliance with NOx and CO startup emission limits, then startup and shutdown NOx and CO testing shall be conducted every 12 months. If an annual startup and shutdown NOx and CO relative accuracy audit demonstrates that the CEM data is certifiable, the startup and shutdown NOx and CO testing frequency shall return to the once every seven years schedule. [District Rule 1081] Federally Enforceable Through Title V Permit
32. Source testing to determine compliance with the NOx, CO, VOC and NH3 emission rates (lb/hr and ppmvd @ 15% O2) and PM10 emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 2201, 4.0 and 4703, 6.3.1; and 40 CFR 60.4400(a)] Federally Enforceable Through Title V Permit
33. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract, or (ii) monitored weekly. If the sulfur content is less than or equal to 1.0 gr/100 dscf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume until compliance is demonstrated for eight consecutive weeks. [District Rule 2201, 4.0; and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)] Federally Enforceable Through Title V Permit
34. The following test methods shall be used: NOx - EPA Method 7E or 20 or CARB Method 100; CO - EPA Method 10 or 10B or CARB Method 100; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201a and 202; ammonia - BAAQMD ST-1B; and O2 - EPA Method 3, 3A, or 20 or CARB Method 100. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081, 5.0 and 4703, 6.3.1, 6.4.1 thru 6.4.3; and 40 CFR 60.4400(a)(1)(i)] Federally Enforceable Through Title V Permit
35. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

36. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081, 7.2 & 7.3] Federally Enforceable Through Title V Permit

37. A mass or volumetric fuel flow meter that meets the requirements of 40 CFR Part 75 shall be installed, utilized and maintained to measure the amount of natural gas combusted in the unit. [District Rules 2201, 4.0 and 4703] Federally Enforceable Through Title V Permit

38. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NOx, CO and O2 concentrations. Continuous emissions monitor(s) shall monitor emissions during all types of operation, including during startup and shutdown periods, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080, 4.0 & 5.0; 2201, 4.0 and 4703, 6.2.1; 40 CFR 60.4340(b)(1) and 40 CFR 60.4345(a)] Federally Enforceable Through Title V Permit

39. The NOx and O2 CEMS shall be installed and certified in accordance with the requirements of 40 CFR Part 75. The CO CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 4A (PS 4A), or shall meet equivalent specifications established by mutual agreement of the District, the CARB, and the EPA. [District Rule 1080, 6.3, 6.5 & 6.6, and 40 CFR 60.4345(a)] Federally Enforceable Through Title V Permit

40. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour or shall meet equivalent specifications established by mutual agreement of the District, the CARB and the EPA. [District Rule 1080, 6.4; and 40 CFR 60.4345(b) and 40 CFR 60.13(e)(2)] Federally Enforceable Through Title V Permit

41. The CEMS data shall be reduced to hourly averages as specified in 40 CFR 60.13(h) and in accordance with 40 CFR 60.4350, or by other methods deemed equivalent by mutual agreement with the District, the CARB, and the EPA. [District Rule 1080, 7.2 and 40 CFR 60.4350(a)(b)(c)(e) & (f)] Federally Enforceable Through Title V Permit

42. In accordance with 40 CFR Part 60, Appendix F, 5.1, the CO CEMS must be audited at least once each calendar quarter, by conducting cylinder gas audits (CGA) or relative accuracy audits (RAA). CGA or RAA may be conducted three of four calendar quarters, but no more than three calendar quarters in succession. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080, 8.0 and 40 CFR Part 60 Appendix F, 5.1.2] Federally Enforceable Through Title V Permit

43. The owner/operator shall perform a RATA for CO as specified by 40 CFR Part 60, Appendix F, 5.1.1, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080, 8.0 and 40 CFR Part 60 App. F, 5.1.1] Federally Enforceable Through Title V Permit

44. The NOx and O2 CEMS shall be audited in accordance with the applicable requirements of 40 CFR Part 75. Linearity reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080] Federally Enforceable Through Title V Permit

45. Upon written notice from the District, the owner or operator shall provide a summary of the data obtained from the CEMS. This summary shall be in the form and the manner prescribed by the District. [District Rule 1080, 7.1] Federally Enforceable Through Title V Permit

46. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEMS data polling software system and shall make CEMS data available to the District's automated polling system on a daily basis. Upon notice by the District that the facility's CEMS is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEMS data is sent to the District by a District-approved alternative method. [District Rule 1080, 7.1] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

47. The owner or operator shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080, 7.3 and 2201, 4.0; and 40 CFR 60.7(b)] Federally Enforceable Through Title V Permit

48. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081] Federally Enforceable Through Title V Permit

49. Monitor Downtime is defined as any unit operating hour in which the data for NOx, O2 concentrations is either missing or invalid. [40 CFR 60.4380(b)(2)] Federally Enforceable Through Title V Permit

50. The owner or operator shall maintain records of the following items on the combustor tuning activities: (1) date on which combustor tuning activity occurs, (2) description of each combustor tuning activity, (3) reason why each combustor tuning activity is required, (4) documentation (such as operating manuals, letters, e-mails, etc.) showing that each combustor tuning activity is necessary. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit

51. The owner or operator shall maintain records of the following items: (1) hourly and daily emissions, in pounds, for each pollutant listed in this permit on the days startup, shutdown and/or combustor tuning activities of the gas turbine system occur, (2) hourly and daily emissions, in pounds, for each pollutant in this permit on the days startup, shutdown and/or combustor tuning activities of the gas turbine system do not occur, (3) quarterly emissions, in pounds, for each pollutant listed in this permit, and (4) the combined CO emissions (12 consecutive month rolling total) , in pounds, for permit unit N-2697-5 and N-2697-7. [District Rule 2201, 4.0] Federally Enforceable Through Title V Permit

52. The owner or operator shall maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, total hours of operation, the type and quantity of fuel used, mode of start-up (cold, warm, or hot), duration of each start-up, duration of each shutdown, and duration of each combustor tuning event. [District Rules 2201, 4.0 and 4703, 6.26, 6.28, 6.2.11] Federally Enforceable Through Title V Permit

53. The owner or operator shall maintain all records of required monitoring data and support information for a period of five years from the date of data entry and shall make such records available to the District upon request. [District Rules 2201, 4.0 and 4703, 6.2.4; 40 CFR 60.7(f)] Federally Enforceable Through Title V Permit

54. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the District. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Date, time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative, except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080, 8.0; 40 CFR 60.4375(a) and 40 CFR 60.4395] Federally Enforceable Through Title V Permit

55. The owner or operator shall submit to the District information correlating the NOx control system operating parameters to the associated measured NOx output. The information must be sufficient to allow the District to determine compliance with the NOx emission limits of this permit when the CEMS is not operating properly. [District Rule 4703, 6.2.5] Federally Enforceable Through Title V Permit

56. The owners and operators of each affected source and each affected unit at the source shall have an Acid Rain permit and operate in compliance with all permit requirements. [40 CFR 72.9(a)(2)] Federally Enforceable Through Title V Permit

57. The owners and operators and, to the extent applicable, designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR part 75. [40 CFR 75] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

58. The emissions measurements recorded and reported in accordance with 40 CFR part 75 shall be used to determine compliance by the unit with the Acid Rain emissions limitations and emissions reduction requirements for sulfur dioxide and nitrogen oxides under the Acid Rain Program. [40 CFR 75.1] Federally Enforceable Through Title V Permit

59. The owners and operators of each source and each affected unit at the source shall: (i) Hold allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR 73.34(c)) not less than the total annual emissions of sulfur dioxide for the previous calendar year from the unit; and (ii) Comply with the applicable Acid Rain emissions limitations for sulfur dioxide. [40 CFR 73 and 40 CFR 72.9(c)(1)] Federally Enforceable Through Title V Permit

60. Each ton of sulfur dioxide emitted in excess of the Acid Rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 77] Federally Enforceable Through Title V Permit

61. Allowances shall be held in, deducted from, or transferred among Allowance Tracking System accounts in accordance with the Acid Rain Program. [40 CFR 72.9(c)(4)] Federally Enforceable Through Title V Permit

62. An allowance shall not be deducted in order to comply with the requirements under 40 CFR part 73, prior to the calendar year for which the allowance was allocated. [40 CFR 73.35 and 40 CFR 72.9(c)(5)] Federally Enforceable Through Title V Permit

63. An allowance allocated by the Administrator under the Acid Rain Program is a limited authorization to emit sulfur dioxide in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the Acid Rain permit application, the Acid Rain permit, or the written exemption under 40 CFR 72.7 and 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72] Federally Enforceable Through Title V Permit

64. An allowance allocated by the Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72.2] Federally Enforceable Through Title V Permit

65. The designated representative of an affected unit that has excess emissions of sulfur dioxide in any calendar year shall submit a proposed offset plan, as required under 40 CFR part 77. [40 CFR 77.3 and 40 CFR 72.9(e)(1)] Federally Enforceable Through Title V Permit

66. The owners and operators of an affected unit that has excess emissions of sulfur dioxide or nitrogen oxides in any calendar year shall: (i) Pay without demand the penalty required, and pay up on demand the interest on that penalty; and (ii) Comply with the terms of an approved offset plan, as required by 40 CFR part 77. [40 CFR 77.4(k); 40 CFR 77.6; and 40 CFR 72.9(e)(2)] Federally Enforceable Through Title V Permit

67. The owners and operators of the each affected unit at the source shall keep on site the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority: (i) The certificate of representation for the designated representative for the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24; provided that the certificate and documents shall be retained on site beyond such five-year period until such documents are superceded because of the submission of a new certificate of representation changing the designated representative. [40 CFR 72.9(f)(1)(i) and 40 CFR 72.9(f)(1)(ii-iv)] Federally Enforceable Through Title V Permit

68. The owners and operators of each affected unit at the source shall keep on site each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the Administrator or permitting authority; (ii) All emissions monitoring information, in accordance with 40 CFR part 75; (iii) Copies of all reports, compliance certifications and other submissions and all records made or required under the Acid Rain Program; (iv) Copies of all documents used to complete an Acid Rain permit application and any other submission that demonstrates compliance with the requirements of the Acid Rain Program. [40 CFR 75.3(c) and 40 CFR 72.9(f)(2)] Federally Enforceable Through Title V Permit

PERMIT UNIT REQUIREMENTS CONTINUE ON NEXT PAGE

69. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR 75 Subpart I. [40 CFR 75] Federally Enforceable Through Title V Permit

APPENDIX C
Actual Emission Data – Jan 2019 through May 2024

Table B-1 LEC Turbine Baseline Data

Month	CEMS Heat Input MMBtu/mo	Heat Input 24-mo avg MMBtu/mo	Turbine Load MWe	Op Time hr	Turbine Avg Load MWe	Turbine Avg Heat Input MMBtu/hr	CEMS CO lb/month	CO 24-mo avg lbs/yr	CEMS NOx lb/month	NOx 24-mo avg lbs/yr	CEMS VOC lb/month	VOC Test lb/MMBtu	Calculated VOC lb/month	VOC 24-mo avg lbs/yr
May-24	33,285	7,551,050	3,137	21.1	148.5	1,575.2	2,163.3	46,550	303.1	44,964	24.9	0.00149	49.7	6,925
Apr-24	20,663	7,534,408	1,648	15.5	106.3	1,333.1	1,485.9	45,468	194.8	44,812	15.1	0.00149	30.9	6,900
Mar-24	82,826	7,524,076	7,835	45.1	173.8	1,837.3	845.2	44,725	525.0	44,715	62.0	0.00149	123.7	6,885
Feb-24	520,908	7,482,663	49,620	271.9	182.5	1,916.2	1,633.8	44,303	3,104.7	44,452	389.7	0.00149	778.1	6,823
Jan-24	1,076,388	7,332,298	104,036	552.8	188.2	1,947.1	775.3	46,433	6,058.1	43,879	806.5	0.00149	1,607.8	6,618
Dec-23	1,017,610	6,996,040	97,818	524.1	186.7	1,941.7	165.1	48,773	5,813.2	42,383	763.1	0.00149	1,520.0	6,151
Nov-23	763,718	6,901,242	73,292	394.5	185.8	1,936.1	2,415.3	51,737	4,242.7	42,251	574.7	0.00149	1,140.8	6,083
Oct-23	886,217	7,186,772	84,620	488.4	173.3	1,814.6	6,463.4	51,661	5,425.8	44,187	666.8	0.00149	1,323.7	6,627
Sep-23	229,330	7,410,444	21,712	126.9	171.1	1,807.2	3,089.5	49,047	1,364.6	45,523	173.5	0.00149	342.5	7,078
Aug-23	1,052,759	7,988,948	98,741	588.7	167.7	1,788.2	4,056.4	47,565	5,927.1	48,997	792.1	0.00149	1,572.5	8,065
Jul-23	780,321	8,161,934	72,944	429.1	170.0	1,818.5	1,636.3	45,837	4,454.0	50,247	587.0	0.00051	395.1	8,446
Jun-23	73,655	8,483,353	6,680	43.6	153.3	1,690.1	1,439.4	45,106	487.3	52,291	55.3	0.00051	37.3	9,134
May-23	20,513	9,092,790	1,935	14.7	131.4	1,392.6	3,308.9	45,032	217.7	55,978	15.5	0.00051	10.4	9,920
Apr-23	0	9,648,031	0	0.0	0.0	0.0	0.0	45,079	0.0	59,438	0.0	0.00051	0.0	10,618
Mar-23	1,009,519	9,648,031	96,390	541.7	178.0	1,863.8	9,213.0	45,079	6,266.7	59,438	757.6	0.00051	511.1	10,618
Feb-23	877,203	9,511,149	83,680	458.2	182.6	1,914.5	7,032.5	41,933	5,190.4	58,686	659.1	0.00051	444.1	10,820
Jan-23	1,190,442	9,590,484	113,735	611.4	186.0	1,947.0	6,653.3	39,222	7,160.8	59,304	894.4	0.00051	602.7	11,243
Dec-22	1,360,616	9,096,467	130,388	691.5	188.6	1,967.6	3,204.7	39,640	7,863.3	56,690	1,022.4	0.00051	688.9	11,067
Nov-22	1,162,409	8,981,763	111,276	594.5	187.2	1,955.3	3,335.2	41,137	6,928.5	56,454	872.9	0.00051	588.5	11,427
Oct-22	728,629	8,627,504	68,142	414.0	164.6	1,759.8	3,312.9	44,915	4,412.5	54,875	549.4	0.00051	368.9	11,415
Sep-22	735,891	8,576,809	67,961	435.2	156.2	1,690.9	4,070.0	46,701	4,434.1	54,830	552.6	0.00051	372.6	11,620
Aug-22	970,111	8,479,942	90,377	576.2	156.9	1,683.7	8,761.0	48,891	5,907.5	54,546	732.6	0.00051	491.2	11,771
Jul-22	386,187	8,505,515	36,101	245.7	146.9	1,571.7	11,593.4	48,474	2,602.2	54,894	288.6	0.00167	644.9	12,161
Jun-22	122,903	8,586,306	11,567	81.1	142.6	1,515.1	6,445.9	50,221	1,043.1	55,564	92.2	0.00167	205.2	11,840
May-22	0	8,662,750	0	0.0	0.0	0.0	0.0	52,333	0.0	56,047	0.0	0.00167	0.0	11,738
Apr-22	0	8,662,750	0	0.0	0.0	0.0	0.0	52,333	0.0	56,047	0.0	0.00167	0.0	11,738
Mar-22	0	8,662,750	0	0.0	0.0	0.0	0.0	52,333	0.0	56,047	0.0	0.00167	0.0	11,738
Feb-22	220,177	8,662,750	21,214	120.3	176.3	1,830.2	5,895.3	52,333	1,958.1	56,047	165.4	0.00167	367.7	11,738
Jan-22	403,872	8,552,662	38,465	223.0	172.5	1,810.9	5,455.2	49,385	3,066.5	55,068	304.1	0.00167	674.4	11,554
Dec-21	828,013	8,583,820	79,228	433.7	182.7	1,909.3	6,093.1	48,129	5,548.3	54,904	625.7	0.00167	1,382.7	11,219
Nov-21	1,334,777	8,842,506	128,075	688.5	186.0	1,938.6	2,262.3	45,711	8,115.9	55,938	1,003.1	0.00167	2,229.0	10,531
Oct-21	1,333,562	8,624,008	126,828	691.7	183.4	1,928.0	1,236.3	46,309	8,098.0	54,447	1,004.4	0.00167	2,227.0	9,419
Sep-21	1,386,338	8,566,966	132,412	720.0	183.9	1,925.5	125.1	46,997	8,311.3	53,896	1,046.8	0.00167	2,315.1	8,309
Aug-21	1,398,730	8,146,872	133,978	731.6	183.1	1,911.8	600.4	48,834	8,428.2	51,358	1,056.1	0.00167	2,335.8	7,152
Jul-21	1,423,159	7,808,169	135,658	744.0	182.3	1,912.8	173.4	53,220	8,541.7	49,354	1,073.5	0.00124	1,770.8	5,987
Jun-21	1,292,529	7,448,818	123,757	691.3	179.0	1,869.6	1,291.3	56,496	7,860.5	47,242	974.7	0.00124	1,608.2	5,103
May-21	1,130,995	6,877,053	108,944	599.4	181.8	1,886.9	3,402.8	56,663	7,138.0	43,767	849.3	0.00124	1,407.3	4,299
Apr-21	0	6,335,001	0	0.0	0.0	0.0	0.0	56,209	0.0	40,410	0.0	0.00124	0.0	3,596
Mar-21	735,755	6,340,356	71,114	386.8	183.9	1,902.3	2,920.9	56,484	4,763.6	40,462	555.2	0.00124	915.5	3,596
Feb-21	1,035,873	5,972,478	99,915	540.6	184.8	1,916.3	1,610.5	55,024	6,425.6	38,080	780.9	0.00124	1,288.9	3,138
Jan-21	202,408	5,454,542	19,800	115.0	172.2	1,760.7	7,490.7	54,219	1,932.3	34,867	151.9	0.00124	251.8	2,494
Dec-20	1,131,209	5,353,338	109,538	601.5	182.1	1,880.6	6,198.8	50,473	7,391.3	33,901	852.0	0.00124	1,407.5	2,368
Nov-20	453,891		44,083	255.9	172.2	1,773.4	10,889.7		3,770.3		340.8	0.00124	564.8	1,664
Oct-20	627,239		59,737	346.7	172.3	1,809.3	6,885.4		4,324.0		471.5	0.00124	780.4	1,382
Sep-20	542,157		51,409	312.2	164.7	1,736.5	8,449.6		3,865.0		409.1	0.00124	674.6	991
Aug-20	1,021,257		97,766	563.1	173.6	1,813.5	7,928.8		6,604.3		773.6	0.00124	1,270.7	654
Jul-20	547,768		52,210	324.9	160.7	1,685.8	15,086.0		3,942.7		411.5	0.00001	3.0	19
Jun-20	275,791		25,295	174.2	145.2	1,583.0	10,670.5		2,008.4		207.6	0.00001	1.5	17
May-20	0		0	0.0	0.0	0.0	0.0		0.0		0.0	0.00001	0.0	17
Apr-20	0		0	0.0	0.0	0.0	0.0		0.0		0.0	0.00001	0.0	17
Mar-20	0		0	0.0	0.0	0.0	0.0		0.0		0.0	0.00001	0.0	17
Feb-20	0		0	0.0	0.0	0.0	0.0		0.0		0.0	0.00001	0.0	17
Jan-20	466,188		44,415	253.8	175.0	1,836.7	2,942.3		2,739.5		351.3	0.00001	2.5	17
Dec-19	1,345,385		128,063	702.9	182.2	1,914.0	1,256.6		7,616.3		1,016.0	0.00001	7.3	15
Nov-19	897,782		85,687	478.5	179.1	1,876.4	3,459.0		5,132.1		675.7	0.00001	4.9	12
Oct-19	1,219,478		115,657	647.6	178.6	1,883.2	2,612.9		6,995.9		920.1	0.00001	6.6	9
Sep-19	546,150		51,646	303.4	170.2	1,800.0	3,797.6		3,236.0		409.9	0.00001	3.0	6
Aug-19	721,324		67,827	411.3	164.9	1,753.6	9,373.3		4,421.3		542.2	0.00001	3.9	4
Jul-19	704,457		66,416	397.2	167.2	1,773.5	6,726.1		4,315.9		528.8	0.00001	3.8	2
Jun-19	149,000		13,982	85.5	163.5	1,742.1	1,624.7		911.6		111.5	0.00001	0.8	1
May-19	46,891		4,096	34.9	117.4	1,343.6	2,494.1		424.4		35.5	0.00001	0.3	0
Apr-19	10,710		962	7.8	124.1	1,381.9	551.4		102.8		8.1	0.00001	0.1	0
Mar-19	0		0	0.0	0.0	0.0	0.0		0.0		0.0	0.00001	0.0	0
Feb-19	0		0	0.0	0.0	0.0	0.0		0.0		0.0	0.00001	0.0	0
Jan-19	0		0	0.0	0.0	0.0	0.0		0.0		0.0	0.00001	0.0	0
max =	1,423,159	9,648,031					max =	56,663	max =	59,438			max =	12,161

APPENDIX D
Projected Actual Emissions

Table B-3 LEC FYE 2025 Budget Run with Forward Curves from November 2023

NOx =	160	lb/start	VOC =	16	lb/start
NOx =	15.54	lb/hr	VOC =	3.79	lb/hr
NOx =	0.007368	lb/MMBtu	VOC =	0.001799	lb/MMBtu

Year	Month	Number of Starts	Generation MWh	Fuel mmBTUs	NOx lb/month	NOx 5% Increase lb/month	NOx ton/year	VOC lb/month	VOC 5% Increase lb/month	VOC ton/year
2025	1	30	160,844	1,160,293	13,349	13,776		2,567	2,671	
2025	2	28	109,705	806,333	10,421	10,718		1,898	1,971	
2025	3	31	83,751	639,346	9,671	9,906		1,646	1,703	
2025	4	0	0	0	0	0		0	0	
2025	5	3	3,995	38,334	762	777		117	120	
2025	6	28	57,321	458,913	7,861	8,030		1,273	1,315	
2025	7	21	126,903	923,512	10,164	10,505		1,997	2,080	
2025	8	19	133,761	969,628	10,184	10,541		2,048	2,135	
2025	9	6	174,193	1,232,965	10,044	10,499		2,313	2,424	
2025	10	15	81,044	592,149	6,763	6,981		1,305	1,358	
2025	11	14	50,526	375,558	5,007	5,145		899	933	
2025	12	24	157,051	1,125,457	12,132	12,547	49.7	2,408	2,509	9.6
2026	1	31	160,566	1,157,986	13,492	13,919	49.8	2,579	2,683	9.6
2026	2	28	113,780	835,043	10,633	10,940	49.9	1,950	2,025	9.6
2026	3	33	98,507	745,145	10,770	11,045	50.5	1,868	1,935	9.8
2026	4	0	0	0	0	0	50.5	0	0	9.8
2026	5	0	0	0	0	0	50.1	0	0	9.7
2026	6	16	25,557	214,823	4,143	4,222	48.2	642	662	9.4
2026	7	28	135,862	991,513	11,785	12,151	49.0	2,231	2,320	9.5
2026	8	17	162,580	1,164,085	11,297	11,726	49.6	2,366	2,470	9.7
2026	9	9	179,690	1,269,175	10,791	11,259	50.0	2,427	2,541	9.7
2026	10	18	89,603	653,855	7,698	7,938	50.4	1,464	1,523	9.8
2026	11	16	60,782	448,609	5,865	6,031	50.9	1,063	1,103	9.9
2026	12	26	156,512	1,121,691	12,425	12,838	51.0	2,433	2,534	9.9
2027	1	30	159,619	1,151,988	13,288	13,712	50.9	2,552	2,655	9.9
2027	2	28	117,239	858,794	10,808	11,124	51.0	1,993	2,070	9.9
2027	3	25	74,146	560,620	8,131	8,337	49.7	1,408	1,459	9.7
2027	4	0	0	0	0	0	49.7	0	0	9.7
2027	5	0	0	0	0	0	49.7	0	0	9.7
2027	6	10	18,255	155,494	2,746	2,803	49.0	440	454	9.6
2027	7	31	137,993	1,009,775	12,400	12,772	49.3	2,312	2,403	9.6
2027	8	23	157,273	1,132,100	12,021	12,438	49.6	2,404	2,506	9.6
2027	9	8	181,533	1,279,141	10,705	11,176	49.6	2,429	2,544	9.6
2027	10	11	57,522	418,941	4,847	5,001	48.1	929	967	9.3
2027	11	8	24,542	185,507	2,647	2,715	46.5	462	478	9.0
2027	12	25	158,177	1,133,675	12,353	12,771	46.4	2,439	2,541	9.0
2028	1	28	158,338	1,143,530	12,906	13,327	46.2	2,505	2,607	9.0
2028	2	29	121,254	887,239	11,177	11,504	46.4	2,060	2,139	9.0
2028	3	30	78,181	598,637	9,211	9,431	47.0	1,557	1,610	9.1
2028	4	22	56,092	432,383	6,706	6,865	50.4	1,130	1,169	9.7
2028	5	2	2,840	26,820	518	527	50.7	80	83	9.8
2028	6	15	27,592	226,925	4,072	4,156	51.3	648	669	9.9
2028	7	26	133,981	977,413	11,362	11,722	50.8	2,174	2,262	9.8
2028	8	21	159,604	1,145,821	11,802	12,225	50.7	2,397	2,500	9.8
2028	9	9	178,879	1,263,053	10,746	11,211	50.7	2,416	2,529	9.8
2028	10	16	64,366	475,737	6,065	6,240	51.3	1,112	1,154	9.9

2028	11	9	29,345	219,825	3,060	3,141	51.6	539	559	9.9
2028	12	24	151,183	1,086,414	11,845	12,245	51.3	2,338	2,436	9.9
2029	1	28	158,739	1,144,765	12,915	13,336	51.3	2,507	2,610	9.9
2029	2	28	112,603	828,794	10,587	10,892	51.0	1,939	2,013	9.8
2029	3	37	106,380	804,535	11,848	12,144	52.4	2,039	2,111	10.0
2029	4	26	68,907	525,984	8,035	8,229	53.0	1,362	1,409	10.2
2029	5	3	4,242	40,055	775	790	53.2	120	124	10.2
2029	6	10	19,389	161,622	2,791	2,850	52.5	451	465	10.1
2029	7	31	134,543	987,606	12,237	12,600	53.0	2,272	2,361	10.1
2029	8	31	138,546	1,012,329	12,419	12,792	53.2	2,317	2,408	10.1
2029	9	17	167,640	1,194,269	11,519	11,959	53.6	2,420	2,527	10.1
2029	10	18	78,983	583,861	7,182	7,397	54.2	1,338	1,391	10.2
2029	11	9	30,585	228,694	3,125	3,209	54.22	555	576	10.22
2029	12	22	140,141	1,011,163	10,970	11,343	53.8	2,171	2,262	10.1
2030	1	31	153,128	1,109,085	13,132	13,540	53.9	2,491	2,590	10.1
2030	2	27	109,428	806,758	10,264	10,561	53.7	1,883	1,956	10.1
2030	3	33	107,879	811,183	11,257	11,556	53.4	1,987	2,060	10.1
2030	4	20	64,158	483,867	6,765	6,943	52.8	1,190	1,234	10.0
2030	5	3	4,480	41,755	788	803	52.8	123	127	10.0
2030	6	9	17,779	150,138	2,546	2,602	52.7	414	428	10.0
2030	7	31	120,483	891,795	11,531	11,859	52.3	2,100	2,180	9.9
2030	8	31	130,989	962,243	12,050	12,404	52.1	2,227	2,313	9.8
2030	9	21	156,885	1,125,354	11,652	12,066	52.1	2,360	2,461	9.8
2030	10	17	69,562	516,791	6,528	6,718	51.8	1,201	1,248	9.7
2030	11	14	51,417	383,191	5,063	5,205	52.8	913	948	9.9
2030	12	26	134,165	974,179	11,338	11,697	53.0	2,168	2,256	9.9
	max =	37	**max =**	1,279,141	13,492	**max =**	54.22	2,579	**max =**	10.22
				12 mo max =	161,904		**12 mo max =**	30,944		

Note, the facility has stated that they will not exceed the currently permitted emission limits, despite the 12 month max values presented here. These calculations were provided to justify their choice of PE1 as their projected actual emissions and to justify the use of unused baseline emissions.

APPENDIX E
Project Emissions Increase Calculation

Project Emission Increase Calculations

Project Emissions Increase = PAE – BAE – UBC

Where: PAE = Projected Actual Emissions, and
BAE = Baseline Actual Emissions
UBC = Unused baseline capacity

Projected Actual Emissions (PAE)
Over the next five years, NCPA has projected a maximum of 37 startups per month and a maximum monthly heat input rate of 1,279,141 MMBtu (Appendix D). Based on these projections, NCPA has provided the following PAE values.

Projected Actual Emissions (PAE)	
Pollutant	PAE (lb/year)
NOx	151,415
VOC	33,003
SOX	45,679
PM10	67,488
CO	198,000

Baseline Actual Emissions (BAE)
For electric utility steam generating units, according to according to 40 CFR 51.165(a)(1)(xxxv)(B), the BAE are calculated as the average, in tons/year, at which the emissions unit actually emitted during any 24-month period selected by the operator within the previous 5-year period. Note that a different consecutive 24-month period can be used for each regulated NSR pollutant.

NOx:
NCPA have chosen to use 24-month period from May 2021 through April 2023. During this period, per CEMS data, the emission rate was 59,438 lb-NOx/yr (see Appendix C). Thus,

BAE = 59,438 lb-NOx/yr

VOC:
NCPA have chosen to use 24-month period from August 2020 through July 2022. During this period, per CEMS data, the emission rate was 12,161 lb-VOC/yr (see Appendix C). Thus,

BAE = 12,161 lb-VOC/yr

<u>SOx:</u>
NCPA have chosen to use 24-month period from May 2021 through April 2023. During this period, the average heat input was 9,648,031 MMBtu/yr (see Appendix C). During a July 18, 2022 source test, SOx emissions were 0.000135 lb/MMBtu. Thus,

BAE = 0.000135 lb-SOx/MMBtu x 9,648,031 MMBtu/yr
= 1,302 lb-SOx/yr

<u>PM_{10}:</u>
NCPA have chosen to use 24-month period from May 2021 through April 2023. During this period, the average heat input was 9,648,031 MMBtu/yr (see Appendix C). During a July 18, 2022 source test, PM10 emissions were 0.0036 lb/MMBtu. Thus,

BAE = 0.0036 lb-PM10/MMBtu x 9,648,031 MMBtu/yr
= 34,733 lb-PM_{10}/yr

<u>CO:</u>
NCPA have chosen to use 24-month period from June 2019 to May 2021. During this period, per CEMS data, the emission rates was 56,663 lb-CO/yr (see Attachment C). Thus,

BAE = 56,663 lb-CO/yr

BAE is summarized in the table below.

Baseline Actual Emissions (BAE)	
Pollutant	BAE (lb/year)
NOx	54,651
VOC	9,801
SOx	1,302
PM10	34,733
CO	56,663

<u>Unused Baseline Capacity (UBC)</u>
As described in 40 CFR 51.165(a)(1)(xxviii)(B), when using historical data and company's expected business activity and highest projections of business activity to determine PAE, the portion of the emissions after the project that the existing unit could have accommodated before the project (during the same 24-month baseline period used to determine BAE) and that are unrelated to the particular project (including emissions increases due to product demand growth) are to be excluded.

Historical monthly records over the past 5 years (January 2019 through May 2024, see Appendix C) indicate that the plant has operated at a monthly heat input as high as 1,423,159 MMBtu/month. This equates to plant operating near 94%[4] of the physical capacity of the unit, based on the nominal rating of the turbine. Notably, as this is an average monthly heat input, it can be inferred that on shorter time scales the plant operated even nearer to its maximum physical capacity. The equipment at this plant (compressor, turbine, HRSG, steam turbine and all other auxiliary components) have been and will continue to be maintained according to manufacturer suggested intervals such that generation capacity stays at design capacity. The plant could have been operated for up to 12 months at full physical capacity should there have been a need to fulfill electric demand in that year.

This facility has permitted quarterly emission limits that limit emissions to a level below what would be emitted if the turbine were to continuously operate at its maximum pre-project physical capacity and at the permitted emission rate. In fact, the turbine could exceed those quarterly emission limits if it were to operate continuously at 94% load at the permitted emission rates. Therefore, the pre-project configuration of the turbine has the physical capacity to achieve the currently permitted emission limits (PE1). Therefore, the UBC for this project is the difference between PE1 and the BAE. UBC is calculated as shown below:

UBC = PE1 - BAE

Unused Baseline Capacity (UBC)			
Pollutant	PE1 (lb/year)	BAE (lb/yr)	UBC (lb/year)
NOx	151,415	59,438	91,977
VOC	33,003	12,161	20,842
SOx	53,436	1,302	52,134
PM10	78,840	34,733	44,107
CO	198,000	56,663	141,337

[4] (1,423,159 MMBtu/month ÷ (2,109 MMBtu/hr x 24 hr/day x 30 days/month) = 93.7% ~94%

Project Emissions Increase For Modified Emission Units
The Project Emissions Increase (EI) is calculated as shown below:

EI = PAE – BAE – UBC *Negative EI are equated to 0*

Project Emissions Increase For Modified Emissions Units (EI)						
Permit Units	Item	NO_X	SOx	PM_{10}	CO	VOC
N-2697-5 (Modified emission unit)	PAE (lb/yr)	151,415	45,679	67,488	198,000	33,003
	BAE (lb/yr)	59,438	1,302	34,733	56,663	12,161
	UBC (lb/yr)	91,977	52,134	44,107	141,337	20,842
	EI (lb/yr)	0	0	0	0	0

As seen in the table above, the Project Emissions Increases for NOx, SOx, PM10, CO, and VOC are 0 lb/yr.

APPENDIX F
Quarterly Net Emissions Change

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post-Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

$PE2_{quarterly} = PE2_{annual} \div 4$ quarters/year

$PE1_{quarterly} = PE1_{annual} \div 4$ quarters/year

Quarterly NEC [QNEC]			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NOx	37,853.75	37,853.75	0
SOx	13,359	13,359	0
PM10	19,710	19,710	0
CO	49,500	49,500	0
VOC	8,250.75	8,250.75	0

APPENDIX G
Top Down BACT Analysis

Top-Down BACT Analysis

The District BACT Clearinghouse does not currently include a BACT guideline that applies to uniform load gas turbines ≥50 MW with heat recovery; this project triggers BACT for NOx, SOx, CO, and VOC. Therefore, a project-specific BACT analysis will be performed in accordance with the District BACT policy to determine the BACT requirements for the proposed operation.

Step 1 - Identify All Possible Control Technologies

The following BACT clearinghouse references were reviewed to determine what control technologies have been required:

– EPA RACT/BACT/LAER clearinghouse
– CARB BACT clearinghouse
– South Coast AQMD (SCAQMD) BACT clearinghouse
– Bay Area AQMD (BAAQMD) BACT clearinghouse
– Sacramento Metro AQMD (SMAQMD) BACT clearinghouse
– San Joaquin Valley APCD (SJVAPCD) BACT clearinghouse

The following rules were also consulted:

- South Coast AQMD Rule 1135 (Last amended January 7, 2022)
- Bay Area AQMD Regulation 9, Rule 9 (Last amended December 6, 2006)
- Sacramento Metro AQMD Rule 413 (Last amended March 24, 2005)
- San Joaquin Valley APCD Rule 4703 (Last amended September 20, 2007)

A survey of source test results from units of this class and category located in the San Joaquin Valley APCD was also performed. The purpose of the survey was to determine the emission levels that are currently being achieved in practice.

Survey of BACT Guidelines:

<u>EPA RACT/BACT/LAER clearinghouse</u>

The EPA RACT/BACT/LAER clearinghouse (RBLC)[5] does not include general guidelines, only determinations made by individual agencies. The RBLC was queried for approved operations between 9/11/2019 through 9/11/2024 using process type of "15.210 – Large Combustion Turbines (>25 MW), Combined Cycle and Cogeneration, Natural Gas (includes propane & liquefied petroleum gas)" category. Twenty-two relevant results were identified. When a determination specified emission factors on multiple averaging periods, the shortest period was recorded. Determinations which are "draft" or were made for turbines which have not been constructed are included, but are not considered for establishment of Achieved in Practice BACT. The emission factors required by these determinations are summarized in the following table.

[5] https://cfpub.epa.gov/rblc/index.cfm?action=Search.AdvancedSearch

EPA RBLC Large Combustion Turbines with Combined Cycle or Cogeneration								
RBLC ID	**Date**	**Facility Name**	**Heat Input Rating or MW Rating**	**NOx (ppmvd @ 15% O2, averaging period)**	**SOx (lb/MMBtu, averaging period)**	**CO (ppmvd @ 15% O2, averaging period)**	**PM10 (lb/MMBtu)**	**VOC (ppmvd @ 15% O2, averaging period)**
*IN-0371	1/11/2024	Wabash Valley Resources, LLC	2,292 MMBtu/hr	2.0	N/A	N/A	N/A	N/A
*IN-0365	6/19/2023	Maple Creek Energy, LLC	4,200 MMBtu/hr	2.0, 3-hr	0.0019, 3-hr	2.0, 3-hr	0.0074	1.0, 3-hr
*IN-0365	6/19/2023	Maple Creek Energy, LLC	3,800 MMBtu/hr	2.0, 3-hr	0.0017, 3-hr	2.0 , 3-hr	0.0049	1.0, 3-hr
TX-0939	3/13/2023	Entergy Texas, Inc. Orange County Advanced Power Station	1,215 MW	N/A	N/A	2.4 , 1-hr	0.005	2.0, 3-hr
MI-0455	2/1/2023	Midland Cogeneration Venture Limited Partnership	4,198 MMBtu/hr	2.0, 24-hour	N/A	2.0, 24-hr	N/A	2.4, 1-hr
MI-0454	12/20/2022	Lansing Board of Water and Light LBWL-Erickson Station	667 MMBtu/hr	25, 4-hr	N/A	4.0, 24-hr	N/A	3.0, 1-hr
**IL-0133	7/29/2022	Lincoln Land Energy Center	3647 MMBtu/hr	2.0, 3-hr	N/A	1.8, 3-hr	0.0041	1.0, 3-hr
AK-0088	7/7/2022	Alaska Gasline Development Corporation Liquefaction Plant	384 MMBtu/hr	2.0, 3-hr	N/A	2.0, 3-hr	0.007	2.0, 3-hr
**MI-0451	6/23/2022	Marshal Energy Center, LLC	3,064 MMBtu/hr	2.5, 24-hr	N/A	2.0, 24-hr	0.005	2.0, 1-hr
**MI-0452	6/23/2022	Marshal Energy Center, LLC	3,064 MMBtu/hr	2.0, 24-hr	N/A	2.0, 24-hr	0.005	2.0, 1-hr
**LA-0391	6/3/2022	Magnolia Power LLC	5,081 MMBtu/hr	2.0, 24-hr	N/A	2.0, 24-hr	0.008	2.0, 1-hr
*WV-0033	1/5/2022	Mountain State Clean Energy, LLC	1,275 MW	2.0, 3-hr	0.06	2.0, 3-hour	0.006	2.0, 3-hr
*PA-0336	12/14/2021	Calpine Mid-Merit LLC	2,513 MMBtu/hr	N/A	N/A	2.0 ppmvd	N/A	N/A
FL-0371	6/7/2021	Shady Hills Energy Center, LLC	3,622 MMBtu/hr	2.0, 24-hr	N/A	4.3, 3-hr	N/A	N/A
**PA-0334	4/29/2021	Renovo Energy Center LLC	4,546 MMBtu/hr	2.0, 1-hr	0.0012	1.5, 1-hr	0.005	1.6, 1-hr
**TX-0915	3/17/2021	NRG Cedar Bayou LLC	Not Reported	N/A	N/A	4.0, 3-hr	N/A	1.0, 3-hr
*VA-0335	12/18/2020	Panda Stonewall LLC	2,554 MMBtu/hr	2	N/A	2	0.0037	1.5
AL-0328	11/9/2020	Alabama Power Company	744 MW	2.0, 3-hr	N/A	N/A	0.004	N/A
WI-0300	9/1/2020	Nemadji Trail Energy Center	4,671 MMBtu/hr	2.0, 24-hr	N/A	1.5, 168-hr	N/A	2.7, 168-hr
WI-0299	8/20/2020	WPL - Riverside Energy Center	168 MW	N/A	N/A	N/A	N/A	N/A
LA-0364	1/6/2020	FG LA LLC	2,222 MMBtu/hr	2.0, 12-month	N/A	4	N/A	4
*MI-0445	11/26/2019	Indeck Niles, LLC	3,421 MMBtu/hr	2.0, 24-hr	0.06, 1-hr	4.0, 24-hr	N/A	4.0, 1-hr

*Draft Determination. Requirements from these determinations are recorded, but are not considered further for establishment of District BACT requirements.
**These projects have not completed construction. Therefore, the emission factors have not been verified with source testing and are not considered further.
“N/A” indicates no standard was specified, or a standard was specified in units which do not allow for comparison.

The most stringent requirements achieved by installed installations from the RBLC search are presented below.

NOX:
2.0 ppmvd @ 15% O2, 1-hr average

SOX:
None of the determinations reviewed included requirement of add-on controls for SOx and it is understood that SOx emission rate is principally determined by sulfur content of the natural gas fuel. The sulfur content of pipeline natural gas fuel is expected to vary based on location and be controlled by the utility provider. Therefore, the SOx standard is taken as "Pipeline Fuel".

CO:
2.0 ppmvd @ 15% O2, 3 hr average

PM10:
Emission factors as low as 0.004 lb/MMBtu were identified. However, none of the determinations reviewed included add-on controls for PM10 and it is understood that PM10 emission rate is principally determined by sulfur content of the natural gas fuel. The sulfur content of pipeline natural gas fuel is expected to vary based on location and be controlled by the utility provider. Therefore, the PM10 standard is taken as "Pipeline Fuel".

VOC:
2.0 ppmvd @ 15% O2, 3 hr average

CARB BACT Clearinghouse

The CARB BACT clearinghouse[6] contains BACT determinations made by agencies in California. These determinations are discussed in following sections.

In July 2002, CARB published "Guidance for the Permitting of Electrical Generation Technologies"[7]. This guidance document does not address units rated at greater than or equal to 50 MW. Table I-1 lists the following requirements for combined cycle turbines between 12 and 50 MW:

NOX:
2.5 ppmvd @ 15% O2, 3-hr average

SOX:
N/A

[6] https://ww2.arb.ca.gov/our-work/programs/technology-clearinghouse/clearinghouse-tools/bact-guidelines-tool
[7] https://ww2.arb.ca.gov/sites/default/files/2020-08/guidelines.pdf

CO:
6 ppmvd @ 15% O2, 3-hr average

PM10:
An emisison limit corresponding to natural gas fuel with fuel sulfur content of no more than 1 grain/100 scf

VOC:
2.0 ppmvd @ 15% O2, 3 hr average

South Coast AQMD (SCAQMD) BACT clearinghouse

The SCAQMD BACT clearinghouse has a guideline for Combined Cycle Natural-Gas Turbines, established in 2018 for a 56.1 MW unit at the Glenarm Power Plant in Pasadena[8]. The applicable requirements from this guideline are summarized in the table below.

SCAQMD: Glenarm Power Plant Gas Turbine	
Process: Subcategory/Rating/Size	**Control Technology**
NG-fired Combined Cycle Turbine / 56.1 MW	**NOx:** 2 ppmvd @ 15% O2, 1-hour rolling average **SOx:** N/A **PM10:** N/A **CO:** 2.0 ppmvd @ 15% O2, 1-hour rolling average **VOC:** 2.0 ppmvd @ 15% O2, 1-hour average

Bay Area AQMD (BAAQMD) BACT clearinghouse

The BAAQMD BACT clearinghouse[9] has a guideline for Gas Turbines with Combined Cycle ≥ 40 MW (7/18/2003) . The requirements are shown in the table below:

[8] https://www.aqmd.gov/docs/default-source/bact/laer-bact-determinations/aqmd-laer-bact/part-b-section_1-2-1-19-combined-cycle-gas-turbine.pdf?sfvrsn=14
[9] https://www.baaqmd.gov/permits/permitting-manuals/bact-tbact-workbook

BAAQMD BACT Guideline		
Guideline	**Category & Class**	**Control Technology**
89.1.6	Gas Turbine, Combined Cycle ≥ 40 MW	**NOx:** Achieved in Practice - 2.5 ppm, dry @ 15% O2 Technologically Feasible: - 2.0 ppm, dry @ 15% O2 **SOx:** Achieved in Practice: - Natural Gas Fuel (sulfur content not to exceed 1.0 grain/scf) Technologically Feasible: - No standard **PM10:** Achieved in Practice: - Natural Gas Fuel (sulfur content not to exceed 1.0 grain/scf) Technologically Feasible: - No standard **CO:** Achieved in Practice: 4.0 ppm, dry @ 15% O2 Technologically Feasible: - No standard **VOC:** Achieved in Practice: - 2.0 ppm, dry @ 15% O2 Technologically Feasible: - No standard

Sacramento Metro AQMD (SMAQMD) BACT clearinghouse

The SMAQMD clearinghouse[10] has no active guidelines for gas turbines.

San Joaquin Valley APCD (SJVAPCD) BACT clearinghouse

The SJVAPCD clearinghouse has a rescinded BACT guideline for Gas Turbines ≥ 50 MW with uniform load and heat recovery (10/1/2002). The requirements are shown in the table below:

[10] https://www.airquality.org/businesses/permits-registration-programs/best-available-control-technology-(bact)

SJVAPCD BACT Guideline		
Guideline	**Equipment**	**Control Technology**
3.4.2 (2002)	Gas Turbine ≥ 50 MW, Uniform Load, with Heat Recovery	**NOx:** Achieved in Practice - 2.5 ppm dry @ 15% O2 (1-hr average, excluding startup and shutdown), selective catalytic reduction or equivalent Technologically Feasible: - 2.0 ppm dry @ 15% O2 (1-hr average, excluding startup and shutdown), selective catalytic reduction or equivalent **SOx:** Achieved in Practice - PUC-regulated natural gas OR Non-PUC-regulated gas with no more than 0.75 grams S/100dscf, or equvalent Technologically Feasible: - No standard **PM10:** Achieved in Practice - Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel OR equivalent **CO:** Achieved in Practice - 6.0 ppmv @ 15% O2 (oxidation catalyst or equal) Technologically Feasible: - 4.0 ppmv @ 15% O2 (oxidation catalyst or equal) **VOC:** Achieved in Practice - 2.0 ppmv @ 15% O2 Technologically Feasible: - 1.5 ppmv @ 15% O2

Survey of Applicable Rules and Regulations:

SJVAPCD Rule 4703: Stationary Gas Turbines applies to all stationary gas turbine systems which are subject to District permitting requirements and with ratings equal to or greater than 0.3 MW or with a maximum heat input rating of more than 3 MMBtu/hr. This rule specifies maximum NOx and CO emission factors. The applicable requirements are 3 ppmvd NOx @ 15% O2, and 200 ppmv CO @ 15% O2.

SCAQMD Rule 1134: Emissions of Oxides of Nitrogen From Stationary Gas Turbines (amended 2/4/2022) applies to all stationary gas turbines with rating equal to or greater than 0.3 MW. This rule specifies a maximum NOx emission factor of 2 ppmvd @ 15% O2 on a 60-minute rolling average. This rule does not include requirements for other criteria pollutants.

SCAQMD Rule 1135: Emissions of Oxides of Nitrogen From Electricity Generating Facilities (amended 1/7/2022) applies to combined cycle gas turbines at electricity generating facilities. Electricity generating facilities are defined as facilities with capacity to provide 50 MW or more to state or local electrical grid systems. This rule specifies a maximum NOx emission factor of 2 ppmvd @ 15% O2 on a 60-minute rolling average. This rule does not include requirements for other criteria pollutants.

BAAQMD Regulation 9, Rule 9: Nitrogen Oxides and Carbon Monoxide From Stationary Gas Turbines (amended 12/6/2006) applies to stationary gas turbines. This rule specifies a maximum NOx emission factor for natural gas turbines based on heat input rating. The most stringent NOx emission factor which could apply to gas turbines with output equal to or greater than 50 MW is 0.15 lb-NOx/MWhr or 5 ppmv. This rule does not include requirements for other criteria pollutants.

SMAQMD Rule 413: Stationary Gas Turbines (amended 3/24/2005) applies to stationary gas turbines operated on liquid or gaseous fuel with rating greater than 0.3 MW or heat input rating greater than 3 MMBtu/hr. This rule specifies a maximum NOx emission factor for natural gas turbines based on heat input rating. The most stringent NOx emission factor which could apply to turbines with output equal to or greater than 10 MW is 9 ppmv. This rule does not include requirements for other criteria pollutants.

The most stringent requirements identified from source category specific prohibitory rules is 2 ppmvd NOx @ 15% O2, and 200 ppmv CO @ 15% O2. The NOx limit is equally stringent as that established in the SCAQMD BACT determination discussed above. The CO emission limits in these prohibitory rules are less stringent than the requirements established in the above review of BACT guidelines.

Survey of Permit Requirements:

A query of gas turbines >50 MW with heat recovery (combined cycle, cogeneration, simple cycle with cogeneration) within the SJVAPCD returned 28 permits. The emission limits of these operations are summarized in the table below.

Combined Cycle Gas Turbines ≥ 50 MW in SJVAPCD							
Facility Name	Permit Number	Rating (MW)	NOx	SOx	PM10	CO	VOC
NORTHERN CALIFORNIA POWER	N-2697-5-8	294	2	6.1	9	2.0	1.4
MODESTO IRRIGATION DISTRICT	N-3233-4-7	87	2.5	NG Fuel	2.5	6	2
MRP SAN JOAQUIN ENERGY, LLC	N-4597-1-11	88	2.0	2.03	4.4	2.0	1.5
MRP SAN JOAQUIN ENERGY, LLC	N-4597-2-11	88	2.0	2.03	4.4	2.0	1.5
WALNUT ENERGY CENTER AUTHORITY	N-7172-1-5	84	2.0	1.05	7.0	4.0	1.4
WALNUT ENERGY CENTER AUTHORITY	N-7172-2-5	84	2.0	1.05	7.0	4.0	1.4
KERN RIVER COGENERATION FACILITY	S-88-1-23	75	3[A]	0.9	5.0	25	12.0[B]
KERN RIVER COGENERATION FACILITY	S-88-2-24	75	3[A]	0.9	5.0	25	12.0[B]
KERN RIVER COGENERATION FACILITY	S-88-3-23	75	3[A]	0.9	5.0	25	12.0[B]
KERN RIVER COGENERATION FACILITY	S-88-4-25	75	3[A]	0.9	5.0	25	12.0 [B]
SYCAMORE COGENERATION FACILITY	S-511-1-21	75	3[A]	0.9	5.0	25	2.5 [B]
SYCAMORE COGENERATION FACILITY	S-511-2-22	75	3[A]	0.9	5.0	25	2.5 [B]
SYCAMORE COGENERATION FACILITY	S-511-3-22	75	3[A]	0.9	5.0	25	2.5 [B]
SYCAMORE COGENERATION FACILITY	S-511-4-21	75	3[A]	0.9	5.0	25	2.5 [B]
AERA ENERGY LLC	S-1135-224-30	78.2	5.0[A]	0.92	9.98	25	9.0 [B]
AERA ENERGY LLC	S-1135-225-29	78.2	5.0[A]	0.92	9.98	25	9.0 [B]
AERA ENERGY LLC	S-1135-226-28	78.2	5.0[A]	0.92	9.98	25	9.0 [B]
CXA LA PALOMA, LLC	S-3412-1-23	262	2.5	3.89	11.0	6	2.1[C]
CXA LA PALOMA, LLC	S-3412-2-24	262	2.5	3.89	11.0	6	2.1[C]
CXA LA PALOMA, LLC	S-3412-3-24	262	2.5	3.89	11.0	6	2.1[C]
CXA LA PALOMA, LLC	S-3412-4-19	262	2.5	3.89	11.0	6	2.1[C]
ELK HILLS POWER LLC	S-3523-1-13	171	2.5	3.6	15.0	4	2.0
ELK HILLS POWER LLC	S-3523-2-13	171	2.5	3.6	15.0	4	2.0
PASTORIA ENERGY FACILITY LLC	S-3636-1-10	168	2.5	3.495	9.0	6.0	2.0
PASTORIA ENERGY FACILITY LLC	S-3636-2-10	168	2.5	3.495	9.0	6.0	2.0
PASTORIA ENERGY FACILITY LLC	S-3636-3-10	168	2.5	3.495	9.0	6.0	2.0
SUNRISE POWER CO	S-3746-1-12	160	2.0	1.55	17.8	4.0	2.0
SUNRISE POWER CO	S-3746-2-12	160	2.0	1.55	17.8	4.0	2.0

NOx emission factors are in ppmvd @ 15% O2 over a 1 hour rolling average. CO emission factors are in ppmvd @ 15% O2 over a 3 hour rolling average. VOC emission factors are ppmvd @ 15% O2 (as methane) over a 3 hour rolling average. PM10 and SOx emission factors are in lb/hr.

A. This NOx limit is based on a 3-hr average.

B. This VOC limit is in lb/hr

C. This VOC limit was in ppmvd as propane @ 15% O2, and was converted to “as methane” by multiplying by the carbon ratio, 3.

Based on review of these permits, the most stringent requirements on the permits within the SJVAPCD are as follows:

NOx: 2.0 ppmvd @ 15% O2 (1-hr average, excluding startup and shutdown), fast start or equivalent

This emission limit has been affirmed by source testing at Northern California Power (facility N-2697), MRP San Joaquin Energy (facility N-4597), and Walnut Energy Center Authority (facility N-7172). Additionally, the Northern California Power turbine (N-2697-5-8) is equipped with fast start technologies which reduces the time required to achieve the steady state emission level. Therefore, the performance standard will include “fast start or equivalent”.

SOx: PUC-Regulated natural gas or Equivalent

None of the permits reviewed included requirement of control methods for SOx and it is understood that SOx emission rate is principally determined by sulfur content of the natural gas fuel. The sulfur content of pipeline natural gas fuel is expected to vary based on location and be controlled by the utility provider. Therefore, the SOx standard is taken as “PUC-Regulated Natural Gas or Equivalent”.

PM10: Natural Gas or LPG fired

None of the determinations reviewed included requirement of control methods for PM10 and it is understood that PM10 emission rate is principally determined by sulfur content of the natural gas fuel. The sulfur content of pipeline natural gas fuel is expected to vary based on location and be controlled by the utility provider. Therefore, the PM10 standard is taken as “PUC-Regulated Natural Gas or Equivalent”.

CO: 2.0 ppmvd @ 15% O2, 3-hr average

This emission limit has been affirmed by source testing at Northern California Power (facility N-2697) and MRP San Joaquin Energy (facility N-4597).

VOC: 1.4 ppmvd @ 15% O2, 3-hr average

This emission limit has been affirmed by source testing at Northern California Power (facility N-2697).

Summary of Permit Requirements:

The following requirements are the most stringent identified for each criteria pollutant which have been identified. No Technologically Feasible performance standards were identified which were more stringent than those which were identified as Achieved in Practice:

NOx: 2.0 ppmvd @ 15% O2 (1-hr average, excluding startup and shutdown), fast start or equivalent

SOx: PUC-Regulated natural gas (Achieved in Practice)

PM10: PUC-Regulated natural gas (Achieved in Practice

CO: 2.0 ppmvd @ 15% O2, 3-hr average (Achieved in Practice)

VOC: 1.4 ppmvd @ 15% O2, 3-hr average (Achieved in Practice)

Step 2 - Eliminate Technologically Infeasible Options

There are no technologically infeasible options listed in Step 1. All of the emission control options under consideration are based on either current BACT requirements, current rule requirements, or actual source test data. Therefore, no further discussion is required.

Step 3 - Rank Remaining Control Technologies by Control effectiveness

The requirements identified have been achieved in practice. Therefore, ranking is not necessary. The requirements identified are summarized below.

NOx: 2.0 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (selective catalytic reduction or equivalent), fast start or equivalent (Achieved in Practice)

SOx: PUC-regulated natural gas OR Non-PUC regulated gas with no more than 0.75 grains S/100 dscf, or equivalent (Achieved in Practice)

PM10: PUC-regulated natural gas OR Non-PUC regulated gas with no more than 0.75 grains S/100 dscf, or equivalent (Achieved in Practice

CO: 2.0 ppmv @ 15% O2 (3-hr average, excluding startup and shutdown); Oxidation Catalyst or Equivalent (Achieved in Practice)

VOC: 1.4 ppmv @ 15% O2 (as methane, 3-hr average, excluding startup and shutdown); Oxidation Catalyst or Equivalent (Achieved in Practice)

Step 4 - Cost Effectiveness Analysis

The requirements identified are all Achieved in Practice, therefore, cost effectiveness analysis is not applicable.

Step 5 - Select BACT

As mentioned above, this project triggered BACT for NOx, SOX, CO, and VOC. The BACT requirements identified for each pollutant and the proposed method of compliance are listed below.

NOx: 2.0 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown); selective catalytic reduction or equivalent; fast start or equivalent

NCPA has proposed 2.0 ppmvd @ 15% O2 (1-hr average, excluding startup and shutdown). The facility utilizes Siemens Flex Plant 30 fast start technology. Therefore, BACT for NOx is satisfied.

SOX: PUC-regulated natural gas OR Non-PUC regulated gas with no more than 0.75 grains S/100 dscf, or equivalent

NCPA has proposed use of PUC-regulated natural gas. Therefore, BACT for SOx is satisfied.

CO: 2.0 ppmv @ 15% O2 (3-hr average, excluding startup and shutdown); Oxidation Catalyst or Equivalent

NCPA has proposed 2.0 ppmvd @ 15% O2 (3-hr average, excluding startup and shutdown). The facility utilizes an oxidation catalyst. Therefore, BACT for CO is satisfied.

VOC: 1.4 ppmv @ 15% O2 (as methane, 3-hr average, excluding startup and shutdown); Oxidation Catalyst or Equivalent

NCPA has proposed 1.4 ppmvd @ 15% O2 (3-hr average, excluding startup and shutdown). Therefore, BACT for CO is satisfied.

APPENDIX H
RMR / AAQA Summary

San Joaquin Valley Air Pollution Control District
Risk Management Review and Ambient Air Quality Analysis

To:	Matthew Robinson – Permit Services
From:	Will Worthley – Technical Services
Date:	August 26, 2024
Facility Name:	NORTHERN CALIFORNIA POWER
Location:	12745 N THORNTON RD, LODI
Application #(s):	N-2697-5-9
Project #:	N-1243995

1. Summary

1.1 Risk Management Review (RMR)

Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required	Special Permit Requirements
5-9	0.43	0.00	N/A[1]	N/A[1]	No	Yes
Project Totals	0.43	0.00	N/A[1]	N/A[1]		
Facility Totals	>1	0.01	0.00	1.08E-06		

1. There was an increase in hourly emissions only.

1.2 Ambient Air Quality Analysis (AAQA)

Pollutant	Air Quality Standard (State/Federal)				
	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass[1]		N/A		
NO_x	Pass[1]				N/A
SO_x	Pass[1]	N/A		N/A	N/A
PM10				N/A	N/A
PM2.5				N/A	N/A

Notes:
1. There was only an hourly increase in emissions with this project.

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

<u>Unit # 5-9</u>

1. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction.

2. Project Description

Technical Services received a revised request to perform a Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA) for the following:

- Unit -5-9: MODIFICATION OF 294 MW (NOMINAL) COMBINED-CYCLE ELECTRIC GENERATION PLANT CONSISTING OF A SIEMENS INDUSTRIAL FRAME "FLEX PLANT 30" STG6-5000F NATURAL GAS-FIRED TURBINE ENGINE WITH ADVANCED ULTRA LOW-NOX COMBUSTOR SYSTEM, AN UNFIRED HEAT RECOVERY STEAM GENERATOR SERVED BY A SELECTIVE CATALYTIC REDUCTION WITH AMMONIA INJECTION AND AN OXIDIZATION CATALYST AND A STEAM TURBINE GENERATOR: MODIFICATIONS TO COMBUSTOR TO INSTALL GAS TURBINE FX TECHNOLOGIES

3. RMR Report

3.1 Analysis

The District performed an analysis pursuant to the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015) to determine the possible cancer and non-cancer health impact to the nearest resident or worksite. This policy requires that an assessment be performed on a unit by unit basis, project basis, and on a facility-wide basis. If a preliminary prioritization analysis demonstrates that:

- A unit's prioritization score is less than the District's significance threshold and;
- The project's prioritization score is less than the District's significance threshold and;
- The facility's total prioritization score is less than the District's significance threshold

Then, generally no further analysis is required.

The District's significant prioritization score threshold is defined as being equal to or greater than 1.0. If a preliminary analysis demonstrates that either the units', the project's or the facility's total prioritization score is greater than the District threshold, a screening or a refined assessment is required.

If a refined assessment is greater than one in a million but less than 20 in a million for carcinogenic impacts (cancer risk) and less than 1.0 for the acute and chronic hazard indices (non-carcinogenic) on a unit by unit basis, project basis and on a facility-wide basis the proposed application is considered less than significant. For units that exceed a cancer risk of one in a million, Toxic Best Available Control Technology (TBACT) must be implemented.

Air toxics emissions for this project were calculated using the following methods:

- Natural gas usage rates for the proposed operation were provided by the Permit Engineer. These usage rates were speciated into air toxics using the emission factors from table 3.1-3, "Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines" in April 2000 AP 42 Chapter 3 Stationary Internal Combustion Sources, Section 3 Stationary Gas Turbines. Assumes 1,000 Btu's per scf natural gas..

These emissions were input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy, risks from the proposed unit's toxic emissions were prioritized using the procedure in the 2016 CAPCOA Facility Prioritization Guidelines. The prioritization score for this proposed facility was greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required.

The AERMOD model was used, with the parameters outlined below and meteorological data for 18-22 from Stockton (rural dispersion coefficient selected) to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Source Process Rates					
Unit ID	**Process ID**	**Process Material**	**Process Units**	**Hourly Process Rate**	**Annual Process Rate**
5	1	NG Usage	MMscf	0.06	0
5	1	Ammonia	LBS	0.78	0

Point Source Parameters						
Unit ID	**Unit Description**	**Release Height (m)**	**Temp. (°K)**	**Exit Velocity (m/sec)**	**Stack Diameter (m)**	**Vertical/ Horizontal/ Capped**
5	294 MW Turbine	45.72	361	25.31	5.79	Vertical

4. AAQA Report

The District modeled the impact of the proposed project on the National Ambient Air Quality Standard (NAAQS) and/or California Ambient Air Quality Standard (CAAQS) in accordance with District Policy APR-1925 (Policy for District Rule 2201 AAQA Modeling) and EPA's Guideline for Air Quality Modeling (Appendix W of 40 CFR Part 51). The District uses a progressive three level approach to perform AAQAs. The first level (Level 1) uses a very conservative approach. If this analysis indicates a likely exceedance of an AAQS or Significant Impact Level (SIL), the analysis proceeds to the second level (Level 2) which implements a more refined approach. For the 1-hour NO_2 standard, there is also a third level that can be implemented if the Level 2 analysis indicates a likely exceedance of an AAQS or SIL.

The modeling analyses predicts the maximum air quality impacts using the appropriate emissions for each standard's averaging period. Required model inputs for a refined AAQA include background ambient air quality data, land characteristics, meteorological inputs, a receptor grid, and source parameters including emissions. These inputs are described in the sections that follow.

Ambient air concentrations of criteria pollutants are recorded at monitoring stations throughout the San Joaquin Valley. Monitoring stations may not measure all necessary pollutants, so background data may need to be collected from multiple sources. The following stations were used for this evaluation:

Monitoring Stations				
Pollutant	**Station Name**	**County**	**City**	**Measurement Year**
CO	Stockton - University Park	San Joaquin	Stockton	2022
NOx	Stockton - University Park	San Joaquin	Stockton	2022
SOx	Fresno - Garland	Fresno	Fresno	2022

Technical Services performed modeling for directly emitted criteria pollutants with the emission rates below:

Emission Rates (lbs/hour)						
Unit ID	**Process**	**NOx**	**SOx**	**CO**	**PM10**	**PM2.5**
5	1	0.42	0.16	0.26	0.00	0.00

The AERMOD model was used to determine if emissions from the project would cause or contribute to an exceedance of any state of federal air quality standard. The parameters outlined below and meteorological data for 18-22 from Stockton (rural dispersion coefficient selected) were used for the analysis:

The following parameters were used for the review:

Point Source Parameters						
Unit ID	**Unit Description**	**Release Height (m)**	**Temp. (°K)**	**Exit Velocity (m/sec)**	**Stack Diameter (m)**	**Vertical/ Horizontal/ Capped**
5	294 MW Turbine	45.72	361	25.31	5.79	Vertical

5. Conclusion

5.1 RMR

The cumulative acute and chronic indices for this facility, including this project, are below 1.0; and the cumulative cancer risk for this facility, including this project, is less than 20 in a million. In addition, the cancer risk for each unit in this project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit requirements listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

5.2 AAQA

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

6. Attachments

A. Modeling request from the project engineer

B. Additional information from the applicant/project engineer

C. Prioritization score w/ toxic emissions summary

D. Facility Summary

E. AAQA results

APPENDIX I
HAP Calculations

Emissions of non-criteria pollutant hazardous air pollutants are tabulated as shown below.

N-2697-1-9:
This 49 MW NG-fired turbine generator is limited by permit condition to annual heat input of 463 MMBtu/hr (4,055,880 MMBtu/yr or 4,055.88 MMscf/yr). HAP emissions are calculated as shown below.

Name	Natural Gas-Fired Turbines				
Applicability	Use this spreadsheet for Natural Gas-Fired Stationary Gas Turbines. Entries required in yellow areas, output in gray areas.				
Author or updater	Matthew Cegielski		*Last Update*	May 13, 2022	
Facility:					
ID#:					
Project #:					
Inputs	MMscf /hr	MMscf /yr	Formula		
Natural Gas usage rate		4,055.880	Supply the necessary rate in MMscf. Use the dropdown to enter a Y if a catalyst is used. Supply the catalyst control effciency in whole numbers, for example, 70.0 for 70.0% Emissions are calculated by the multiplication of Fuel Rates and Emission Factors.		
VOC Control by Catalyst? Y or N	Y				
Control %	70.00				
Substances	**CAS#**	**Emission Factor lbs/ MMscf**	**LB/HR**	**LB/YR**	**tpy**
1, 3 Butadiene	**106990**	4.30E-04	0.00E+00	1.74E+00	0.0
Acetaldehyde	**75070**	4.00E-02	0.00E+00	1.62E+02	0.1
Acrolein	**107028**	6.40E-03	0.00E+00	2.60E+01	0.0
Benzene	**71432**	8.40E-03	0.00E+00	3.41E+01	0.0
Ethyl Benzene	**100414**	3.20E-02	0.00E+00	1.30E+02	0.1
Formaldehyde	**50000**	4.97E-01	0.00E+00	2.02E+03	1.0
Naphthalene	**91203**	1.30E-03	0.00E+00	5.27E+00	0.0
PAH's	**1150**	2.20E-03	0.00E+00	8.92E+00	0.0
Propylene Oxide	**75569**	2.90E-02	0.00E+00	1.18E+02	0.1
Toluene	**108883**	1.30E-01	0.00E+00	5.27E+02	0.3
Xylenes	**1330207**	6.40E-02	0.00E+00	2.60E+02	0.1
				TOTAL	1.6
References:					
* The emission factors are derived from table 3.1-3, "Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbin *Internal Combustion Sources, Section 3 Stationary Gas Turbines.* Assumes 1,000 Btu's per scf natural gas.					
Emission factors in boxes change by the control efficiency for VOC when a catalyst is used.					

N-2697-4-6:
This 240 bhp diesel-fired emergency engine is limited to 100 hours per year for non-emergency operation. Per N-1083490 the maximum fuel usage rate is 11.9 gal/hr. Therefore, the annual fuel usage is considered to be 1,190 gal/yr. HAP emissions are calculated as shown below.

Name	**Diesel and Biodiesel-Fired Internal Combustion Engines**					
Applicability	Use this spreadsheet for Diesel and Biodiesel-Fired Internal Combustion Engines. (Due to the District's Diesel Screening Methodology, this spreadsheet is not in current use for Diesel, only for Biodiesel; however the Diesel values serve the basis for the Biodiesel blends) Entries required in yellow areas, output in gray areas.					
Author or updater	Matthew Cegielski		*Last Update*	February 22, 2016		
Facility:						
ID#:						
Project #:						
Inputs	1,000 gallons /hr	1,000 gallons /yr	**Formula**			
Diesel Fuel usage		1.2	Supply the necessary rate in 1,000 gallons. Emissions are calculated by the multiplication of Fuel Rates and Emission Factors.			
Substances	**CAS#**	**Diesel Emission Factor lbs/ 1,000 gallons**	**LB/HR**	**LB/YR**	**tpy**	
1,3 Butadiene	**106990**	2.17E-01	0.00E+00	2.59E-01	0.0	
Acetaldehyde	**75070**	7.83E-01	0.00E+00	9.32E-01	0.0	
Acrolein	**107028**	3.39E-02	0.00E+00	4.03E-02	0.0	
Arsenic	**7440382**	1.60E-03	0.00E+00	1.90E-03	0.0	
Benzene	**71432**	1.86E-01	0.00E+00	2.22E-01	0.0	
Cadmium	**7440439**	1.50E-03	0.00E+00	1.79E-03	0.0	
Chlorobenzene	**108907**	2.00E-04	0.00E+00	2.38E-04	0.0	
Chromium	**7440473**	6.00E-04	0.00E+00	7.14E-04	0.0	
Copper	**7440508**	4.10E-03	0.00E+00	4.88E-03	0.0	
Ethyl Benzene	**100414**	1.09E-02	0.00E+00	1.30E-02	0.0	
Formaldehyde	**50000**	1.73E+00	0.00E+00	2.05E+00	0.0	
Hexane	**110543**	2.69E-02	0.00E+00	3.20E-02	0.0	
Hexavalent Chromium	**18540299**	1.00E-04	0.00E+00	1.19E-04	0.0	
Hydrogen Chloride	**7647010**	1.86E-01	0.00E+00	2.22E-01	0.0	
Lead	**7439921**	8.30E-03	0.00E+00	9.88E-03	0.0	
Manganese	**7439965**	3.10E-03	0.00E+00	3.69E-03	0.0	
Mercury	**7439976**	2.00E-03	0.00E+00	2.38E-03	0.0	
Naphthalene	**91203**	1.97E-02	0.00E+00	2.34E-02	0.0	
Nickel	**7440020**	3.90E-03	0.00E+00	4.64E-03	0.0	
PAHs	**1150**	5.59E-02	0.00E+00	6.65E-02	0.0	
Propylene	**115071**	4.67E-01	0.00E+00	5.56E-01	0.0	
Selenium	**7782492**	2.20E-03	0.00E+00	2.62E-03	0.0	
Toluene	**108883**	1.05E-01	0.00E+00	1.25E-01	0.0	
Xylenes	**1330207**	4.24E-02	0.00E+00	5.05E-02	0.0	
Zinc	**7440666**	2.24E-02	0.00E+00	2.67E-02	0.0	
				TOTAL	0.0	
References:						
* The emission factors were based on the May 2001 update of VCAPCD AB 2588 Combustion Emission Factors and the Biodiesel reductions listed in Table VI.B-6 (pg. 93) in the EPA 2002 Draft Technical Report, *A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions*						
Pollutants required for toxic reporting. Current as of update date.						

N-2697-5-9:

This 311 MW NG-fired turbine generator has a maximum rated heat input rate of 2,166 MMBtu/hr. Maximum annual fuel usage is estimated to be (18,974,160 MMBtu/yr or 18,974.16 MMscf/yr). HAP emissions are calculated as shown below.

Name	Natural Gas-Fired Turbines					
Applicability	Use this spreadsheet for Natural Gas-Fired Stationary Gas Turbines. Entries required in yellow areas, output in gray areas.					
Author or updater	Matthew Cegielski		*Last Update*	May 13, 2022		
Facility:						
ID#:						
Project #:						
Inputs	MMscf /hr	MMscf /yr	Formula			
Natural Gas usage rate		18,974.160	Supply the necessary rate in MMscf. Use the dropdown to enter a Y if a catalyst is used. Supply the catalyst control effciency in whole numbers, for example, 70.0 for 70.0% Emissions are calculated by the multiplication of Fuel Rates and Emission Factors.			
VOC Control by Catalyst? Y or N	Y					
Control %	70.00					
Substances	CAS#	Emission Factor lbs/ MMscf	LB/HR	LB/YR	tpy	
1, 3 Butadiene	106990	4.30E-04	0.00E+00	8.16E+00	0.0	
Acetaldehyde	75070	4.00E-02	0.00E+00	7.59E+02	0.4	
Acrolein	107028	6.40E-03	0.00E+00	1.21E+02	0.1	
Benzene	71432	8.40E-03	0.00E+00	1.59E+02	0.1	
Ethyl Benzene	100414	3.20E-02	0.00E+00	6.07E+02	0.3	
Formaldehyde	50000	4.97E-01	0.00E+00	9.43E+03	4.7	
Naphthalene	91203	1.30E-03	0.00E+00	2.47E+01	0.0	
PAH's	1150	2.20E-03	0.00E+00	4.17E+01	0.0	
Propylene Oxide	75569	2.90E-02	0.00E+00	5.50E+02	0.3	
Toluene	108883	1.30E-01	0.00E+00	2.47E+03	1.2	
Xylenes	1330207	6.40E-02	0.00E+00	1.21E+03	0.6	
				TOTAL	7.7	
References:						
* The emission factors are derived from table 3.1-3, "Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbines" in April 2000 *AP 42 Chapter 3 Stationary Internal Combustion Sources, Section 3 Stationary Gas Turbines.* Assumes 1,000 Btu's per scf natural gas.						
Emission factors in boxes change by the control efficiency for VOC when a catalyst is used.						

N-2697-6-3:

HAP emissions from this cooling tower are calculated with non-criteria pollutant concentrations supplied by NCPA (during project N-1083490) and the flow rate of 69,000 gpm.

Cooling Tower

Hazardous Air Pollutant	Concentration in cooling tower return water	Maximum Hourly Emissions (lb/hr) (1)	Maximum Annual Emissions (lb/yr) (2)	Maximum Annual Emissions (tpy)
Arsenic	0 ppm	0.00E+00	0.0	0.0
Cadmium	0.025 ppm	4.32E-06	0.0	0.0
Chromium III	0.025 ppm	4.32E-06	0.0	0.0
Lead	0.05 ppm	8.63E-06	0.1	0.0
Mercury	0 ppm	0.00E+00	0.0	0.0
Nickel	0.025 ppm	4.32E-06	0.0	0.0

Cooling Tower (Continued…)

Hazardous Air Pollutant	Concentration in cooling tower return water	Maximum Hourly Emissions (lb/hr) (1)	Maximum Annual Emissions (lb/yr) (2)	Maximum Annual Emissions (tpy)
Dioxins/furans	--	--	--	--
PAHs	--	--	--	--
Total				**0.0**

(1) Concentration (ppm) x Drift Rate (lb/hr). Drift Rate = 69,000 gpm x 60 min/hr x 5.00E-06 lb/lb-coolant x 8.34 lb-coolant/gal = 172.64 lb/hr
(2) Based on 8,760 hr/yr.

N-2697-7-3:

This 36.5 MMBtu/hr NG-fired boiler has maximum capacity for fuel usage of 319,740 MMBtu/yr (319.74 MMscf/yr). HAP emissions are calculated as shown below.

Name	**Natural Gas-Fired External Combustion**				
Applicability	Use this spreadsheet for Natural Gas-Fired External Combustion (Boilers, heaters, flares). Entries required in yellow areas, output in grey areas.				
Author or updater	Matthew Cegielski		*Last Update*	March 10, 2015	
Facility:					
ID#:					
Project #:					
Inputs	Rate MM scf /hr	Rate MMscf /yr	**Formula**		
< 10 MMBTU/hr	1.00E+00		Choose one of the MMBtu ratings and supply the necessary rate. Emissions are calculated by the multiplication of Fuel Rates and Emission Factors.		
10-100 MMBTU/hr	1.00E+00	319.74			
> 100 MMBTU/hr	1.00E+00				
Flare	1.00E+00				
Substances	**CAS#**	**10-100 MMBTU/hr Emission Factor lbs/ MMscf**	**LB/HR**	**LB/YR**	tpy
Acetaldehyde	**75070**	3.10E-03	3.10E-03	9.91E-01	0.0
Acrolein	**107028**	2.70E-03	2.70E-03	8.63E-01	0.0
Benzene	**71432**	5.80E-03	5.80E-03	1.85E+00	0.0
Ethyl Benzene	**100414**	6.90E-03	6.90E-03	2.21E+00	0.0
Formaldehyde	**50000**	1.23E-02	1.23E-02	3.93E+00	0.0
Hexane	**110543**	4.60E-03	4.60E-03	1.47E+00	0.0
Naphthalene	**91203**	3.00E-04	3.00E-04	9.59E-02	0.0
PAH's	**1151**	1.00E-04	1.00E-04	3.20E-02	0.0
Propylene	**115071**	5.30E-01	5.30E-01	1.69E+02	0.1
Toluene	**108883**	2.65E-02	2.65E-02	8.47E+00	0.0
Xylenes	**1330207**	1.97E-02	1.97E-02	6.30E+00	0.0
				TOTAL	0.1
References:					

* The emission factors are from the table, "Natural Gas Fired External Combustion Equipment" in the May 2001 update of *VCAPCD AB 2588 Combustion Emission Factors*. PAHs emission factor adjusted from table values to subtract Naphthalene portion.

Stationary Source HAP Summary:

The total HAP emissions from the stationary source are calculated to be 9.4 tpy. Therefore, the HAP Major Source thresholds of 10 tpy for any single pollutant or 25 tpy for combined HAP emissions are not exceeded and the stationary source is not a Major Source for air toxics.