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Statement of Basis
Proposed Minor Permit Revision

Owner/Operator:	Burbank City, Burbank Water and Power, SCPPA 164 W. Magnolia Blvd Burbank, CA 91502
Facility ID:	128243
SIC Code:	4931
Equipment Location:	164 W. Magnolia Blvd Burbank, CA 91502
Application No.: **Application Submittal Date:**	624214 September 15, 2020
Responsible Official:	Jorge Somoano General Manager (818) 238-3550

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1.0 INTRODUCTION, SCOPE OF PERMIT, HISTORY AND RECOMMENDATION

Title V is a national operating permit program for air pollution sources established under the Clean Air Act. Facilities subject to Title V must obtain a Title V permit and comply with specific Title V procedures to modify the permit. Title V facilities are required to certify compliance with their permit on an annual basis. The intent of the program is to provide a comprehensive permit document with a clearer determination of applicable requirements, to enhance the enforceability of a source's air quality obligations, as well as to allow greater opportunity for public participation and public access to enforcement actions and facility emissions information.

The Burbank Water and Power (BWP) SCPPA facility is subject to Title V requirements because its potential to emit (PTE) of NOx and VOC emissions are greater than the major source thresholds (see Appendix E). Additionally, the turbine at this facility is defined as an affected unit under the Acid Rain provisions, making this facility an affected source [40CFR Part 72, §72.6(a)(3)]. The facility is not a major source of HAPs (see Appendix D).

The facility has requested to modify their permit by upgrading the combustor in the turbine to allow the turbine to operate at lower loads while still maintaining emission limits.

Facility Description and History

The facility is located in the city of Burbank on a 23 acre parcel bound by Magnolia Blvd. on the north, Lake Avenue on the west, Olive Avenue on the south, and the Western Burbank Flood Control Channel, railway switching yards and Interstate 5 just a few hundred feet to the northeast. The facility is surrounded by light industrial areas to the north, south and east, with some retail space and residential areas to the west. The closest schools are Walt Disney Elementary School located approximately 2000 feet to the west, and William McKinley Elementary School and David Star Jordan Middle School, both located approximately 3600 feet to the south.

The SCPPA facility is a joint ownership project, producing power for the 12 member agencies (11 cities and 1 irrigation district), including the cities of Burbank, Anaheim, Glendale, Pasadena, and others. The plant is operated by the City of Burbank. The facility consists of a combined cycle turbine with an SCR and CO Oxidation catalyst. 19% aqueous ammonia is supplied by a 12000 gallon storage tank. Steam condensing is provided by a cooling tower.

There is a water treatment facility on site consisting of a soda ash and a lime storage silo along with acid storage which is part of a Zero Liquid Discharge (ZLD) system. ZLD is a water treatment process that treats the turbine cooling water on site for re-use. The system eliminates the need to discharge spent cooling water into the local sewer system.

Equipment on site that is exempt from permitting includes air conditioning units and the cooling tower.

It should be noted that BWP also operates a peaking turbine and 2 utility boilers on this site as well. The equipment is permitted under a different ID# (ID# 25638). The equipment under ID# 25638 is owned solely by the City of Burbank and is considered a separate facility for permitting purposes.

Summary of Permitted Equipment

Equipment
Gas Turbine, natural gas, 323.1 MW, combined cycle, with dry low NOx combustors and SCR/CO catalyst
Storage Tank, 19% aqueous ammonia, pressure vessel, 12,000 gallons
Storage Silo, soda ash, 3000 cubic feet, passive fabric filter vent
Storage Silo, lime, 2000 cubic feet, passive fabric filter vent

BWP submitted this Class I application on September 15, 2020 to request a change to the permit to upgrade the turbine combustor. The changes are discussed in more detail in Section 3.0.

The following table summarizes the application submittal.

A/N	Submittal Date	Equipment	Bcat	Fee Schedule	Fee
624214	9/15/2020	Gas Turbine	013709/81	G	22,654.60
624212	9/15/2020	Title V Revision	555009	//////////////	2,729.86
			Expedited Processing		11,327.30
			Total Fee		36,711.76

RECOMMENDATION

After the end of the 45 day EPA review period, pending any comments received, issue a Permit to Construct subject to the conditions listed in Section 7.0.

2.0 EQUIPMENT DESCRIPTION, CONSTRUCTION AND PERMITTING HISTORY:

Section H of the Facility Permit, ID# 128243

Proposed changes or additions are shown in **bold/underline**, proposed deletions are shown in ~~strikethrough~~

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
PROCESS 3: INTERNAL COMBUSTION: POWER GENERATION					
GAS TURBINE NO.1, COMBINED CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL PG7241FA, WITH DRY LOW NOX COMBUSTORS **DLN 2.6+**, 1787 MMBTU/HR WITH A/N: ~~614702~~ **624214** GENERATOR, 181.1 MW GENERATOR, HEAT RECOVERY STEAM STEAM TURBINE, STEAM, 142 MW	D4	C9 C10	NOX: MAJOR SOURCE	**CO**: 2000 PPMV (5) [RULE 407]; **CO**: 2PPMV (4) [RULE 1303]; **NOx**: 2 PPMV (4) [RULE 2005]; **NOx**: 105 PPM NATURAL GAS (8) [40CFR 60 SUBPART GG]; **PM**: 0.1 GR/SCF (5) [RULE 409]; **PM**: 0.01 GR/SCF (5A) [RULE 475]; **PM**: 11 LBS/HR (5C) [RULE 475]; SO2: (9) [40CFR 72 – ACID RAIN]; **SOX**: 150 PPM (8) [40CFR 60 SUBPART GG]; **VOC**: 2 PPMV (4) [RULE 1303]	A63.1, **A195.2**, **A195.3**, **A195.4**, A327.1, **C1.5**, **C1.6**, D29.3, D82.1, D82.2, E57.1, E193.1, I298.1, K67.2
BURNER, DUCT, NATURAL GAS, 583 MMBTU/HR A/N: ~~614702~~ **624214**	D6	C9 C10	NOX: MAJOR SOURCE	**CO**: 2000 PPMV (5) [RULE 407]; **CO**: 2PPMV (4) [RULE 1303]; **NOx**: 2 PPMV (4) [RULE 2005]; **NOx**: 0.2 LBS/MMBTU (8B) [40CFR 60 SUBPART Da]; **PM**:	A63.1, A195.2, A195.3, A195.4, A327.1, C1.1, C1.2, C1.3,

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions and Requirements	Conditions
				0.1 GR/SCF (5) [RULE 409]; **PM**: 0.01 GR/SCF (5A) [RULE 475]; **PM**: 11 LBS/HR (5C) [RULE 475]; **PM**: 0.03 LBS/MMBTU (8A) [40CFR 60 SUBPART Da]; **SOx**: 0.2 LBS/MMBTU (8A) [40CFR 60 SUBPART Da]; **SO2**: (9) [40CFR 72 – ACID RAIN]; **SOx**: 150 PPM (8) [40CFR 60 SUBPART GG]; **VOC**: 2 PPMV (4) [RULE 1303]	D29.3, D82.1, D82.2, E57.1, E193.1, I298.2, K67.2
STACK, NO.1, HEIGHT: 150 FT; DIAMETER: 19 FT A/N: ~~614702~~ **624214**	S12				

The BWP, SCPPA turbine, its SCR and CO catalyst control systems and aqueous ammonia storage tank received their initial Permits to Construct on May 27, 2003. The gas turbine went into commercial operation in 2004.

The City of Burbank has modified the turbine and SCR permit three times since the original construction permit was issued. Under A/N's 464716 and 465931, the turbine's allowable cold start up time was increased from 4 hours to 6 hours, and the distinction between cold and non-cold starts was eliminated. Also, a NOx start up emission limit of 440 lbs, a 3 start up per month limit, and a duct burner monthly fuel use limit were added under that permit revision. Under A/N's 575368 and 575369, the number of monthly start ups was increased from 3 to 5, and the allowable duct burner monthly fuel use limit was increased from 111 mmbtu to 133 mmbtu. Minor corrections were made to the conditions pertaining to the ammonia testing and the allowable ranges for the ammonia injection rate, differential pressure, and exhaust temperature under A/N's 598845 and 598846. Additionally, a Permit to Construct under A/N 614702 was issued to Burbank for the proposed upgrade to the combustor. The project was started but not completed because along the way, the facility discovered problems with the new hardware that was being installed.

The following table is a summary of the application history:

Application No.	Issue Date	Description
386305	5/27/03*	Original P/C
464716	1/16/08*	Modification 1
575368	4/15/16	Modification 2
598845	4/13/18	Modification 3
614702	1/10/20	Modification 4

Permit to Operate issued 11/08/11

The Burbank facility is subject to Title V as well as NOx RECLAIM. The proposed modification will be evaluated as a minor revision to the existing Title V permit at the Burbank Water and

Power, SCPPA facility (ID# 128243). The proposed modification is not considered a major modification under Regulation XIII. The project is also subject to the California Energy Commission (CEC) licensing procedure and an Application for Certification (AFC) to modify the license to account for the proposed change has been submitted with that agency (01-AFC-06). The source is considered minor under PSD, and the proposal under this application is not considered a major modification in and of itself. The Burbank facility is an area source of HAP emissions.

3.0 PROCESS DESCRIPTION

The SCPPA facility is composed of a GE 7FA combustion turbine rated at 181.1 MW, a heat recovery steam generator (HRSG) equipped with a 583 mmbtu/hr duct burner, and one 142.0 MW steam turbine generator. Approximate heat input capacity to the combustion turbine is 1787 mmbtu/hr. The combustion turbine and duct burner use natural gas exclusively. Total plant output is 323.1 MW.

The turbine utilizes dry Low NOx combustion technology, and exhaust gas is further controlled with the use of a CO oxidation catalyst and an SCR control system.

The facility uses inlet air evaporative cooling and inlet gas compression. There is one cooling tower utilizing both potable and reclaimed water.

The exhaust stack is 150 feet high with a diameter of 19 feet.

The following tables outline the equipment specifications.

Turbine Specs

Specification	
Manufacturer/Model	GE/PG72417FA
Fuel Type	Pipeline natural gas
Maximum Heat Input Rating (CTG only)	1787 mmbtu/hr
Maximum Exhaust Flow (CTG only)[1]	55.14 mmscf/hr
Maximum Fuel Consumption (CTG only)	1.702 mmscf/hr @ 1050 btu/scf
CTG Gross Power Output	181.1 MW
Steam Turbine Gross Power Output	85 MW (no duct firing) 142 MW (with duct firing)
Duct Burner Max Heat Input	583 mmbtu/hr
Duct Burner Max Fuel Consumption	0.555 mmscf/hr @ 1050 btu/scf
Gross Plant Power Output	323.1
Maximum Heat Input Rating (CTG + DB)	2370 mmbtu/hr
Maximum Exhaust Flow (CTG + DB)[1]	73.13 mmscf/hr
Maximum Fuel Consumption (CGT + DB)	2.257 mmscf/hr @ 1050 btu/scf
NOx Combustion Control	DLN 9 ppm
Net Plant Heat Rate HHV	7,335 btu/kWh
Net Plant Efficiency HHV	46.5%

1- calculated using an F-factor of 8710 adjusted to 15% O2

Selective Catalytic Reduction Specs

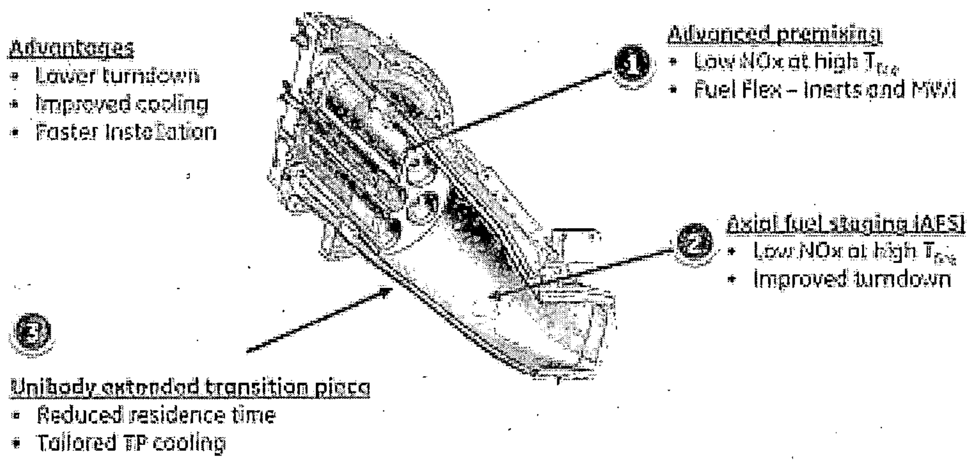
Specification	
Manufacturer	Cormetech
Catalyst Material	Vanadium/Titanium Oxide
Catalyst Volume	1,100 ft3
Maximum Temperature	850 °F
Minimum Temp for NH3 injection	450 °F
Space Velocity[2]	65,300 hr^{-1}
Ammonia Injection Rate	300 lbs/hr of 19% aqueous NH3
Ammonia Slip	5 ppm @ 15% O2
Outlet NOx	2 ppm @ 15% O2 (1 hour average)
Pressure Drop Across SCR	About 4 inch water

Combustor Upgrade

BWP is proposing to upgrade the existing DLN combustor to a configuration called DLN 2.6+. The DLN 2.6+ combustor will provide for a higher turndown ratio and faster ramp rate so that the turbine can be operated at lower loads on occasions when less power output is needed, as well as respond faster to shifts in grid demand. This will increase the flexibility of the unit and enhance its ability to operate under a wider range of power output scenarios. With the existing combustor, maximum turndown is approximately 50-60%. With the DLN 2.6+ combustor upgrade, maximum turndown is 27%.

The DLN 2.6+ combustor is designed to provide better fuel mixing due to the fuel nozzle configuration, and therefore, the unit can maintain its emission limits even at the higher turndown ratios. As in all DLN combustor technology, multiple fuel streams are combusted sequentially in stages to maintain a precise air/fuel ratio. The DLN 2.6+ combustor consists of 6 nozzles and 2 combustion zones, with the first (primary) combustion zone operated at a lower temperature than the second zone. During low load operation, as turbine firing temperature is reduced, the percentage fuel split between the zones can be reduced or turned off. The NOx emissions from the DLN 2.6+ combustor is 9 ppm, which is the same as from the existing combustor. According to the facility, the new combustor configuration will not result in a change to either the heat input rating or the MW output rating of the turbine. And although the DLN 2.6+ modification can be configured to include fast start capability (10 minute starts in some cases), the facility did not choose this particular option for their installation because the turbine is not started often.

DLN2.6+ with Axial Fuel Staging



The DLN 2.6+ combustor upgrade will consist of the combustor system hardware, control modification, upgrade of the gas fuel module, and packaging and accessory skid upgrades. The upgraded combustor also requires the installation of new fuel gas system piping. Total estimated cost of the upgrade as provided by the applicant is $13.9 million. This compares to a total estimated cost for an entirely new turbine package including upgrade of $75 million. Reconstruction is defined under 40 CFR 60.15 as the replacement of components of an existing facility to such an extent that the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost of a comparable entirely new facility. Under this definition, this project is not considered a reconstruction for purposes of federal New Source Performance Standards.

After modification of the combustor, the turbine will undergo a recommissioning. The recommissioning will consist of operating the turbine over various load ranges and operational modes to ensure proper combustion characteristics and emission levels.

Burbank partially completed the combustor upgrade under the Permit to Construct issued in January 2020 (A/N 614702). Burbank finished installing the necessary software on February 24, 2020 and began the recommissioning on February 25, 2020. On March 4, 2020 GE discovered an issue with the flexible piping associated with the Axial Fuel Staging system and determined that further commissioning could not move forward until the issue was addressed. Therefore, the turbine was placed into a temporary configuration with the Axial Fuel Staging disabled. The turbine came back online with this temporary configuration on March 14, 2020 and has been operational since that time. In this configuration, the turbine is able to operate normally, but is unable to turndown to 27%.

A redesign of the flexible piping for the AFS system is required. To finish the process of upgrading the combustor, the manufacturer will install the redesigned flexible piping and test the turbine under load. GE expects to complete the redesign and have it ready for installation by early January 2021. After the redesigned parts are installed, the turbine will be ready to begin the recommissioning phase again. The facility would like to schedule the recommissioning for its upcoming outage beginning in February 2021.

Under A/N 614702, permit conditions A195.2 and A195.3 limited the emissions of NOx and CO during recommissioning as well as the total hours of operation and fuel use. The facility has indicated that the limits were not exceeded during the partial recommissioning that was performed prior to the discovery of the flexible piping issue. The following table summarizes the permit limits and the data provided by Burbank showing compliance with the limits.

Parameter	Permit Limit	Burbank Reported Data
Hours	312 total	187 total
Fuel Use	402 mmscf total	221 mmscf total
NOx	198 lbs/hr	141 lbs/hr
	5,657 lbs total	2,221 lbs total
CO	84 lbs/hr	71 lbs/hr
	792 lbs/day	207 lbs/day
	1,909 lbs total	1,032 lbs total

Completion of the Recommissioning
The turbine will be operated about 156.9 hours during the recommissioning. There will be about 66.2 hours of turbine downtime as well, for a total of 225.8 hours over the course of 11 consecutive days. The turbine will be shutdown and restarted approximately 4 times (including the initial start up). The highest expected NOx mass emission rate during recommissioning is approximately 155.94 lbs/hr corresponding to approximately 55 ppm. The highest expected CO mass emission rate during recommissioning is approximately 55.65 lbs/hr corresponding to approximately 27 ppm. A full breakdown of the recommissioning activities, schedule, and emission estimates is shown in Appendix C.

4.0 REGULATORY APPLICABLILITY DETERMINATIONS

Rule 212 – Standards for Approving Permits
This project is not subject to the Rule 212 public notice requirements because there is no increase in daily maximum criteria pollutant emissions and no increase in toxic emissions, and the facility is not located within 1000 feet of a school (the closest school is Walt Disney Elementary located approximately 2000 feet west of the site).

Rule 401 – Visible Emissions
Visible emissions are not expected under normal operation, and there is no indication of visible emission problems in the South Coast AQMD compliance database. Additionally, the facility has indicated that they do not expect visible emissions during the recommissioning operation.

Rule 402 – Nuisance
Use of ammonia for the SCR system can potentially result in odor problems. However, it is expected that if the facility maintains the 5 ppm ammonia slip level, odor will not be a problem.

Furthermore, there have been no issues of odor or other nuisance problems with the plant since it began operating.

Rule 407 – Liquid and Gaseous Air Contaminants
This rule limits the CO emissions to 2000 ppm. Compliance with the CO limit has been demonstrated through stack testing. The turbine is also subject to a more stringent CO BACT limit of 2 ppm. The facility is required to maintain a CO continuous monitor.

Rule 409 Combustion Contaminants
This rule limits particulate emissions to 0.1 gr/scf at 12% CO2. The test results show that the actual particulate emissions are below this limit. The test results are summarized as follows:

Test Date	Test Load	Results, gr/scf
Initial Testing Oct 2005	No Duct Firing	0.001 at 12% CO2
	Duct Firing	0.001 at 12% CO2
Periodic Testing Nov 2008	No Duct Firing	0.00079 at 12% CO2
	Duct Firing	0.00074 at 12% CO2
Periodic Testing Aug 2011	No Duct Firing	0.00007 at 12% CO2
	Duct Firing	0.00078 at 12% CO2
Periodic Testing July 2014	No Duct Firing	0.00047
	Duct Firing	0.00041
Periodic Testing Sept 2017	Duct Firing	0.0003

The following theoretical calculation also supports the conclusion that the unit is in compliance:

Grain Loading = [(A x B)/(C x D)] x 7000 gr/lb

where:

A = PM10 emission rate during normal operation
B = Rule specified percent of CO2 in the exhaust (12%)
C = Percent of CO2 in the exhaust (approx. 4.29% for natural gas)
D = Stack exhaust flow rate

Estimated grain loading at max load = $\frac{16.22 \text{ lbs/hr}*(7000 \text{ gr/lb})*(12/4.29)}{73 \text{ E6 scf/hr}}$

= 0.0016 gr/scf

Rule 431.1 – Sulfur Content of Gaseous Fuel
In accordance with paragraph (e)(3), an electric utility generating facility is required to maintain a continuous fuel gas monitoring system (CFGMS) to determine the sulfur content of the fuel, and submit monthly reports indicating the amount of gas combusted, the 4 hour average sulfur content of the gas, and the total SOx emissions. Compliance is expected. The rule requires that the natural

gas supplier complies with a 16 ppmv sulfur limit (calculated as H2S). Commercial grade natural gas has an average sulfur content of about 4ppm.

Rule 475 – Electric Power Generating Equipment

This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976, and requires that the equipment meet a limit for combustion contaminants of 11 lbs/hr or 0.01 gr/scf. Compliance is achieved if either the mass limit or the concentration limit is met. Mass PM10 emissions from the turbine with duct firing is estimated at about 16.22 lbs/hr, which translates to 0.0048 gr/scf during natural gas firing at maximum firing load (see calculations below). Therefore, compliance is expected.

$$Stack\ Exhaust\ Flow\left(\frac{scf}{hr}\right) = F_d\ x\ \frac{20.9}{(20.9 - \%O_2)}\ x\ TFD$$

where:
Fd: Dry F factor for fuel type, 8710 dscf/MMBtu
O2: Rule specific dry oxygen content in the effluent stream, 3%
TFD: Total fired duty measured at HHV, 450 MMBtu/hr

$$Combustion\ Particulate\left(\frac{grain}{scf}\right) = \frac{PM_{10}, lb/hr}{Stack\ Exhaust\ Flow, scf/hr}\ x\ 7000\ \frac{gr}{lb}$$

Stack flow = 8710(20.9/17.9)*2350= 23.9 mmscf/hr

Combustion particulate = (16.22/23.9E+06)*7000 = $\boxed{0.0048\ gr/scf}$

Compliance has been verified through the initial source test performed in October 2005, and the 3 year periodic tests. The results of the latest periodic test (September 2017):

PM	=	2.12 lbs/hr
Exhaust rate	=	768,630 dscfm
O2	=	11.74
Grain loading	=	0.0006 gr/scf @ 3% O2 [0.0003 * $\frac{(20.9-3)}{20.9-11.74}$]

RULE 1135 – NOx from electricity Generating Facilities

This rule is applicable to boilers and turbines (except cogen units) at investor owned, or publicly owned electric utilities, or at facilities with > 50 MW capacity, as well as the power generating engines on Catalina Island. The rule sets the NOx limit to 2 ppm for combined cycle turbines, 2.5 ppm to simple cycle turbines, and 5 ppm for utility boilers. The rule also limits NH3 slip to 5 ppm. The limits are all based on a 1 hour rolling average, however, the current limits in the permits for existing facilities can be kept if there is no equipment modification. The rule requires all facilities to have permit limits for the allowed number of start ups, the duration of start ups and the mass emissions during a start up. Requires record keeping for number of starts ups, number of shutdowns, hours of use, and power produced. This rule is a RECLAIM "landing rule" and the limits become effective once the facility has exited the RECLAIM program, or by no later than 1/1/24. The SCPPA turbine permit currently limits the NOx to 2 ppm 3 hour average and NH3 slip limit to 5 ppm 1 hour average..Therefore, the facility does not need to take any further action to comply with this rule once it has exited RECLAIM. Note that the facility is allowed to keep its current 3 hour averaging time for NOx because it is an existing unit under the rule and the averaging time is specified in the permit.

REGULATION XIII/Rule 2005 – New Source Review
The applicant has proposed to upgrade the existing DLN combustor with a DLN 2.6+ combustor to improve the turbine turndown ratio. Once the new combustor is installed, the turbine will be tested, or recommissioned, to ensure proper operation. During the recommissioning, hourly emissions of NOx, CO, and VOC will be higher than normal because at times the turbine will be operated without full SCR and oxidation catalyst control. The highest expected NOx concentration during recommissioning is about 55 ppm, corresponding to about 156 lbs/hr NOx. The highest expected CO concentration during recommissioning is about 27 ppm, corresponding to about 56 lbs/hr CO.

In accordance with Rule 1306, emission increases are calculated on a 30 day average basis for determination of offsets, and on a maximum daily basis for determination of BACT and modeling requirements.

The recommissioning operation will not result in a daily or monthly emissions increase in emissions for CO, VOC, SOx, PM10, or NH3.

Since PM10 and SOx are fuel based emissions, and since the turbine is currently permitted for 100% capacity on a daily and monthly basis, these pollutants are already permitted at their maximum levels, and recommissioning will not increase the emissions.

For CO and VOC, the recommissioning will not result in a mass emissions increase because the turbine will not be operated at its maximum capacity for any day during the recommissioning, and the reduced operating load offsets the higher emission levels during the operating times when the CO and VOC exceed their BACT levels

Therefore, the equipment is not subject to offsets, BACT, or modeling requirements for CO, VOC, SOx, or PM10.

In accordance with Rule 2005, an emission increase is defined as an increase in a source's maximum hourly potential to emit pre modification vs post modification. Any increase is subject to BACT, modeling and offsets (RTCs). The amount of the increase is calculated on an annual basis for determination of the RTC holding requirements.

The modifications proposed under this application will not result in an increase in hourly NOx emissions rate during normal operation of the turbine. However there is an increase when comparing the NOx emissions rate during the recommissioning operation, 155.94 lbs/hr, to either the normal operations emission rate of 13.18 lbs/hr, or even the highest NOx emission rate currently evaluated in the permit, the start up emission rate of 73.33 lbs/hr.

Discussion
The recommissioning operation by definition will be performed, in all likelihood, without full SCR control, therefore, it is being evaluated as a mode of operation that warrants exemption from the 2 ppm NOx BACT limit, not unlike start ups and shutdowns. It follows logically then, that an

analysis of the 2 ppm NOx BACT limit would not be triggered based solely on an emissions rate from an operational mode which is exempt from that limit. Furthermore, the recommissioning operation is a one-time event that must be performed in order to validate the proper operation of the new combustor. When it is completed, the turbine will return to normal operation and the emissions profile will remain unchanged. For all of these reasons, it was determined that neither NOx BACT nor modeling is required.

The annual allowable hours of operation will remain at 8,322 hours per year, however the allowable baseload operation will be reduced from 6,932 hours per year to 6,731.7 hours per year to account for the recommissioning time. This restriction is proposed by the applicant so that there is an overall net decrease in annual NOx PTE and therefore no requirement for additional RTCs.

Potential Overlap of Recommissioning Operation
The facility partially completed the recommissioning operation in March 2020 and is currently scheduled to re-start and complete the recommissioning operation beginning in February 2021. Therefore, there is potential that the second recommissioning will be conducted within 12 months of the first recommissioning. This shouldn't be an issue from a regulatory standpoint for either the time restriction placed on the permit, or the PTE calculations, as discussed below.

Condition C1.5 limits the annual hours of operation based on a 12 month timeframe as opposed to a calendar year, and further specifies that the hourly operation limit applies in any 12 month period in which recommissioning activities are performed. The current limit is 7914 hours per 12 months. Since Burbank was operating the turbine for recommissioning purposes up until March 4, 2020, condition C1.5 is in effect until March 3, 2021. A new condition C1.6 will specify the new annual operating limit is 8096 hours per 12 months for the recommissioning being proposed under this application (both conditions specify that the limit includes all operation <u>except</u> the recommissioning operation since the recommissioning time is limited separately in conditions A195.2, A195.3, and A195.4).

If the recommissioning proposed under this application begins prior to March 4, 2021, conditions C1.5 and C1.6 will overlap. Language will be added to these conditions to clarify that condition C1.5 applies to the recommissioning that was started in 2020, and condition C1.6 applies to the recommissioning that will begin in 2021.

And finally, because the annual PTE is based on calendar year emissions, there will be no overlap of recommissioning emissions to be accounted for in the PTE calculations between the 2020 recommissioning operation and the 2021 recommissioning operation.

<u>RULE 1325/40CFR 51 Appendix S – Federal PM2.5 New Source Review</u>
These rules apply to major polluting facilities, major modifications to a major polluting facility, or any modifications to an existing facility that would constitute a major polluting facility in and of itself. A major polluting facility is defined as a facility located in a federal non-attainment area, which has actual emissions, or a potential to emit of greater than 70 tons per year of PM2.5. A major polluting facility which proposes a modification resulting in a significant increase is required to comply with the following requirements:

- Use of LAER
- Offset PM2.5 emissions at the offset ratio of 1.1:1
- Certification of compliance of emission limits
- Conduct an alternative analysis of the project

Since South Coast AQMD Rule 1325 is not currently SIP approved, the Federally enforceable rule in this case is Appendix S. The applicability standards for Rule 1325 and Appendix S are identical.

As shown in Appendix E, the existing facility is not a major source, and the changes proposed under this application will not result in an emissions increase. Therefore, the Burbank facility will continue to be a non-major polluting facility for PM2.5 and is not subject to the requirements of either Rule 1325 or Appendix S.

Rule 1401 – Toxic Air Contaminants
During recommissioning, the turbine maximum fuel use rate will not increase, therefore hourly emission rates of toxic emissions will not change. During the year which recommissioning occurs, the total annual fuel use will be limited by permit condition so that the maximum annual PTE will not increase. Therefore, for this modification there is no increase in emissions of toxic air contaminants. A health risk assessment was performed for the plant under the initial application in 2001. The analysis found that the plant was in compliance with the applicable standards of this rule. Toxic emissions are calculated in Appendix D.

REGULATION XVII – Prevention of Significant Deterioration
The South Coast Basin where the project is to be located is in attainment for NO2, SO2, CO, and PM10 emissions. Additionally, beginning on January 2, 2011, Greenhouse Gases (GHGs) are a regulated criteria pollutant under the PSD major source permitting program. Therefore each of these pollutants must be evaluated under PSD for this project.

PSD applies on a pollutant-specific basis to a new major source, a significant increase in emissions from an existing major stationary source, or a modification at a non-major source, if the modification is considered major in and of itself. For any of the 28 listed source categories, the major source threshold is 100 tons per year based on actual emissions or potential to emit. The major source threshold is 250 tons/yr for source categories that are not listed. As a natural gas fired combined cycle gas turbine power plant, the Burbank facility falls within the 28 source category definitions, and therefore the applicable threshold is 100 tpy.

If the facility is deemed to be major, Rule 1702 further defines a major modification as a significant emission increase of 40 tpy or more of NO2 or SO2, 15 tpy of PM10, or 100 tons per year or more of CO (determined on a new PTE vs. existing actual basis). The Burbank Water and Power facility is not defined as a major source, because its emissions are below 100 tpy. Furthermore, because the proposed changes under this application result in an emissions decrease, this application does not constitute a major modification in and of itself, and the requirements of PSD do not apply.

Rule 1714 – PSD for Greenhouse Gases
As of January 2, 2011 Greenhouse gases (GHGs) are a regulated New Source Review pollutant under the PSD permitting program when they are emitted by new sources or modifications to

existing sources at amounts equal to or greater than the applicability thresholds of the GHG tailoring rule.

There is no change in the GHG emissions on a future PTE vs existing PTE basis for the proposed modification. Since there is no increase to the PTE, there is no need for a comparison of future PTE vs past actual emissions.

As summarized below, a recent court case determined that increases in GHG emissions alone cannot trigger the review of a permit application under PSD. An analysis under PSD for GHGs emission is only required when a source triggers PSD review for other criteria pollutants.

U.S. Supreme Court Decision in *Utility Air Regulatory Group v. EPA*

On June 23, 2014, the U.S. Supreme Court issued its decision in *Utility Air Regulatory Group v. EPA, 134 S.Ct. 2427 (2014) ("UARG")*. The Court held that EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or title V permit. The Court also held that PSD permits that are otherwise required (based on emissions of other pollutants) may continue to require limitations on GHG emissions based on the application of Best Available Control Technology (BACT). In accordance with the Supreme Court decision, on April 10, 2015, the D.C. Circuit issued an amended judgment in *Coalition for Responsible Regulation, Inc. v. Environmental Protection Agency*, Nos. 09-1322, 10-073, 10-1092 and 10-1167 (D.C. Cir. April 10, 2015), which, among other things, vacated the PSD and title V regulations under review in that case to the extent that they require a stationary source to obtain a PSD or title V permit solely because the source emits or has the potential to emit GHGs above the applicable major source thresholds. The D.C. Circuit also directed EPA to consider whether any further revisions to its regulations are appropriate in light of *UARG*, and if so, to undertake to make such revisions. In response to the Supreme Court decision and the D.C. Circuit's amended judgment, the EPA intends to conduct future rulemaking action to make appropriate revisions to the PSD and operating permit rules.

Rule 2012 – NOx RECLAIM Monitoring, Reporting, and Recordkeeping

The turbine is a major NOx source under RECLAIM. As a major NOx source, the turbine is required to install and maintain a CEMS, which includes both NOx and O2 analyzers, a data handling system, a recording system, and a fuel meter. NOx emissions are required to be reported by electronic transmission daily, and the facility must submit monthly and annual NOx reports.

The CEMS system was installed shortly after commissioning in 2002. Burbank received final certification of their CEMS from South Coast AQMD in a letter dated 8/11/05. The CEMS was modified in 2011, and re-certification was received on 1/18/12. The facility has been reporting their emissions as required under this rule, and has maintained NOx emissions below their cap. Continued compliance is expected.

Regulation XXX – Title V

Burbank is a Title V facility because it is a major source of NOx emissions. The facility currently operates under a valid Title V permit initially issued on 8/19/99, renewed on 5/13/08 and again on 1/9/15. The combustor modification is considered a minor revision in accordance with Rule 3000 because there is no increase in emissions and no significant change in permit conditions. As a minor revision, the permit is subject to a 45 day EPA review and a 30 day review by the affected states.

Federal Regulations

40CFR 60 Subpart Da – New Source Performance Standards for Steam Generating Units
This NSPS applies to electric utility steam generating units rated over 250 mmbtu/hr which were constructed after 9/18/78. This includes fired heat recovery steam generators (HRSG) if the HRSG is not subject to subpart KKKK. The fired HRSG in the SCPPA turbine is subject to this subpart because its heat input rating is 583 mmbtu/hr. The emission standards that apply are as follows:

NOx	1.6 lbs/MWh (construction commenced after 7/9/97 but before 3/1/05) [§60.44Da(d)(1)]
PM	0.03 lbs/mmbtu (construction commenced prior to 3/1/05) [§60.42Da(a)]
SO2	0.2 lbs/mmbtu (construction commenced prior to 2/28/05) [§60.43Da(b)(2)]

These standards apply only to the emissions from the duct burner [§60.40Da (e)(2)]. The standards are based on a 30 operating day rolling average.

Units firing natural gas are not subject to the PM standard [§60.42Da(f)] or opacity standard [§60.42Da(b)(2)]. The regulation requires the installation of a CEMS to measure NOx and O2. An initial performance test is required.

When fired at 100% capacity, the duct burner generates approximately (142-85) = 57 MW.

Calculated emission rates from the duct burner are as follows:

NOx
4.3 lbs/hr/57 MW = 0.075 lbs/MWh
SO2
0.42 lbs/hr/583 mmbtu/hr = 0.0007 lbs/mmbtu

The calculated emissions and the test results show compliance with the subpart Da emission limits. The initial performance test was completed as required. Continued compliance is expected. Source test results are summarized below:

Test Date	SOx, lbs/mmbtu
Initial Testing Oct 2005	0.000
Periodic Testing Nov 2008	0.000
Periodic Testing Aug 2011	0.000
Periodic Testing July 2014	0.000
Periodic Testing Sept 2017	0.000

Note that the test results include emissions from the turbine + duct burner. The duct burner was not tested separately.

40CFR Part 60 Subpart GG - NSPS for Stationary Gas Turbines

Subpart GG applies to the turbine because the unit was constructed after 10/3/77 but before 2/18/05 and its heat input is greater than 10.7 gigajoules per hour (10 MMBtu per hour) at peak load, based on the lower heating value of the fuel fired. Actual unit rating is 1787E+06 btu/hr (LHV) X 1055 joules/btu = 1885.3 gigajoules/hr. The standards which apply to the turbines are as follows (see Appendix H for the calculations):

NOx = 105 ppm (@ 15% O2, dry, 4 hour rolling average)
SOx = 150ppm

Monitoring

§60.334(e) allows turbines constructed after 7/8/04 to elect to monitor NOx emissions by using either a continuous monitoring system, periodic testing, or parametric monitoring. The CEMS must be installed and certified in accordance with PS2 and PS3 of 40CFR 60 Appendix B. Monitoring of the fuel for sulfur content is not required for units fired on natural gas [§60.334(h)(3)].

Testing

A performance test is required within 60 days of installation. Annual RATA tests are required for the pollutants measured with the CEMS.

Since the turbine is controlled with a DLN combustor and an SCR, and is designed to meet a 2.0 ppm NOx limit at all times (except during start ups and shutdowns), compliance with the NSPS emission limits is expected. Burbank Water and Power is required by permit condition to test for SOx emissions once every 3 years. The results of the latest tests show compliance. The turbine is equipped with continuous NOx and O2 monitors certified in accordance with South Coast AQMD Rule 2012. The initial performance test was conducted in 2005. Annual RATA tests are required for the pollutants measured with the CEMS.

Test Date	Test Load	SOx, ppm
Initial Testing Oct 2005	No Duct Firing	1.05
	Duct Firing	1.05
Periodic Testing Nov 2008	No Duct Firing	0.02
	Duct Firing	0.01
Periodic Testing Aug 2011	No Duct Firing	0.01
	Duct Firing	0.02
Periodic Testing July 2014	No Duct Firing	0.003
	Duct Firing	0.003
Periodic Testing Sept 2017	Duct Firing	1.008

40CFR Part 60 Subpart TTTT – NSPS for GHGs from Electric Generating Units

This regulation applies to new combustion turbines which commence construction or reconstruction after January 8, 2014, and which are rated greater than 250 mmbtu/hr heat input and 25 MW power output. Since the SCPPA turbine was constructed in 2003, and is not being reconstructed at this time, this regulation does not apply.

40CFR Part 63 Subpart YYYY - NESHAPS for Stationary Gas Turbines

This regulation applies to gas turbines located at major sources of HAP emissions. A major source is defined as a facility with emissions of 10 tpy or more of a single HAP or 25 tpy or more of a combination of HAPs based on the potential to emit. The turbine does not emit any single HAP at a rate of 10 tpy or more, and the total combined potential HAP emissions from the turbine is less than 1 tpy (note that ammonia is not included in EPA's definition of HAPs). Therefore, Burbank is not classified as a major source of HAPs, and subject is not to this subpart. Calculations can be referenced in Appendix D.

40CFR Part 64 – Compliance Assurance Monitoring

The CAM regulation applies to emission units at major stationary sources required to obtain a Title V permit, which use control equipment to achieve a specified emission limit and which have emissions that are at least 100% of the major source thresholds on a pre-control basis (NOx & VOC = 10 tpy, CO = 50 tpy, PM10 = 100 tpy, and SOx = 100 tpy). The rule is intended to provide "reasonable assurance" that the control systems are operating properly to maintain compliance with the emission limits. The SCPPA turbine has emissions that exceed the major source thresholds on a pre control basis for NOx, CO, and VOC (but not PM10 or SOx), the turbine is subject to an emission limit for NOx, CO, and VOC, and the turbine uses control equipment to meet these limits.

NOx

- ➢ Emission Limit – NOx is subject to a 2.0 ppm 3 hour BACT limit.
- ➢ Control Equipment – NOx is controlled with the SCR
- ✓ Requirement - As a NOx Major Source under Reclaim, the turbine is required to have CEMS under Rule 2012. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(1)(vi).

CO

- ➢ Emission Limit – CO is subject to a 2.0 ppm 1 hour BACT limit.
- ➢ Control Equipment – CO is controlled with the oxidation catalyst.
- ✓ Requirement - The turbine is required to have a CO CEMS by permit condition. The use of a continuous monitor to show compliance with an emission limit is exempt from CAM under 64.2(b)(1)(vi).

VOC

- ➢ Emission Limit – VOC is subject to a 2.0 ppm 1 hour BACT limit.
- ➢ Control Equipment – VOC is controlled with the oxidation catalyst.
- ✓ Requirement – The oxidation catalyst is effective at operating temperatures above 300°F. The facility is required to maintain a temperature gauge in the exhaust (condition D12.2), which will measure the exhaust temperature on a continuous basis and record the readings on an hourly basis. This will allow the operator to ensure that the oxidation catalyst is operating properly. The facility is also required to maintain a CO CEMS which is an indicator of the operating condition of the oxidation catalyst.

40CFR Part 72 – Acid Rain
The facility is subject to the requirements of the federal acid rain program, because the turbine is a power generating unit operated by a utility. The acid rain program is a cap and trade regulation. Facilities are required to cover SO2 emissions with "SO2 allowances". Facilities that were existing when the regulation was adopted in 1993 were given allowances based on past operation. The SCPPA turbine does not have an initial allowance allocation because the unit is not an existing unit under the rule, therefore, SO2 credits to cover operation of the SCPPA turbine must be purchased. The applicant is also required to monitor SO2 emissions through use of fuel gas meters and gas constituent analyses, or, if fired with pipeline quality natural gas, as in the case of the SCPPA turbine, a default emission factor of 0.0006 lbs/mmbtu is allowed. SO2 mass emissions are to be recorded every hour. NOx and O2 must be monitored with CEMS in accordance with the specifications of Part 75. Under this program, NOx and SOx emissions will be reported directly to the U.S. EPA. Compliance is expected. Note that Section K of the permit includes the Acid Rain rule references applicable to this facility, specifically Part 72 and Part 73.

5.0 EMISSIONS AND RISK ANALYSIS

The proposed modification to upgrade the combustor and recommission the turbine will not result in increases to the daily, monthly, and annual emissions for any pollutant. The maximum expected hourly emissions during recommissioning will be higher than the start up emission rate for NOx and VOC, but lower than the start up emission rate for CO. PM10 and SOx hourly emission rates are the same for recommissioning and normal operation since these pollutant emissions rates are fuel based.

Note that the recommissioning operation is a one-time event. After the turbine is recommissioned it will return to normal operation and its emissions profile will revert back to the "pre modification" levels with no changes.

Detailed calculations are shown in Appendix A. Following is a summary.

Maximum Hourly Emissions, All Operations

Pollutant	Start Up	Shutdown	Recommissioning	Normal (No duct firing)	Normal (With duct firing)
	Lbs/hr	Lbs/hr	Lbs/hr	Lbs/hr	Lbs/hr
NOx	73.33	50	155.94	13.18	17.48
CO	83.33	240	55.64	8.02	10.64
VOC	5.00	34	43.76	4.58	6.08
PM10	11.79	11.79	11.79	11.79	16.22
SOx	1.28	1.28	1.28	1.28	1.7
NH3	0	0	12.17	12.17	16.15

Note that the estimated emissions during recommissioning are provided by the manufacturer. However, the City of Burbank has asked to allow for a contingency and set the limit for NOx at 198 lbs/hr and CO at 84 lbs/hr during the recommissioning.

Highest Single Hour Emissions

Pollutant	Operating Scenario	Emissions, lbs/hr
NOx	Recommissioning	155.94
CO	Shut Down	240
VOC	Recommissioning	43.76
PM10	Baseload Operation with Duct Firing	16.22
SOx	Baseload Operation with Duct Firing	1.7
NH3	Baseload Operation with Duct Firing	16.15

Note that the City of Burbank has asked to allow for a contingency and set the limit for NOx at 198 lbs/hr during the recommissioning.

Maximum Daily Emissions

A. Pre Modification Maximum Daily Emissions

Pollutant	Operating Scenario	Daily Emissions
NOx	1 start + 1 shutdown + 12 hrs normal with duct firing + 5.5 hrs normal no duct firing	747.3
CO	1 start + 1 shutdown + 12 hrs normal with duct firing + 5.5 hrs normal no duct firing	791.8
VOC	1 start + 1 shutdown + 12 hrs normal with duct firing + 5.5 hrs normal no duct firing	145.2
PM10	24 hrs normal, 12 hours with duct firing	336.1
SOx	24 hrs normal, 12 hours with duct firing	35.8
NH3	24 hrs normal, 12 hours with duct firing	382.3

B. Maximum Daily Recommissioning Emissions (Post Modification Emissions)

Pollutant	Operating Scenario	Daily Emissions
NOx	Recommissioning Day 11	579.59
CO	Recommissioning Day 11	219.00
VOC	Recommissioning Day 11	126.23
PM10	Recommissioning Day 8	260.50
SOx	Recommissioning Day 8	28.19
NH3	Recommissioning Day 11	272.48

Note that the City of Burbank has asked to allow for a contingency and set the limit for CO at 792 lbs/day during the recommissioning.

Change in Maximum Daily Emissions Pre-Modification vs Post Modification

Pollutant	Pre Modification Daily PTE Emissions	Post Modification Daily PTE Emissions	Change
NOx	747.3	579.59	-167.71
CO	791.8	219.00	-572.80
VOC	145.2	126.23	-18.97
PM10	336.1	260.5	-75.60
SOx	35.8	28.19	-7.61
NH3	382.3	272.48	-109.82

Note that the City of Burbank has asked to allow for a contingency and set the limit for CO at 792 lbs/day during the recommissioning. Even with this higher limit, the maximum daily CO emissions during recommissioning are not more than the pre modification PTE.

Monthly and 30 Day Average Emissions

A. Current PTE Calculation (Pre Modification Emissions)

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	5 starts+5 shutdowns + 240 hrs normal with duct firing + 447.5 hrs normal without duct firing	12,418	405
CO	5 starts+5 shutdowns + 240 hrs normal with duct firing + 447.5 hrs normal without duct firing	9,243	308
VOC	5 starts+5 shutdowns + 240 hrs normal with duct firing + 447.5 hrs normal without duct firing	3,744	125
PM10	720 hrs normal, 240 hrs with duct firing	9,552	318
SOx	720 hrs normal, 240 hrs with duct firing	1,022	34

B. Maximum Monthly Recommissioning Emissions (Post Modification Emissions)

Pollutant	Operating Scenario	Total Monthly Emissions	30-Day Average Emissions
NOx	Recommissioning + 1 start+2 shutdowns + 240 hrs normal with duct firing + 271.2 hrs normal without duct firing	12374	412
CO	Recommissioning + 1 start+1 shutdown + 240 hrs normal with duct firing + 271.2 hrs normal without duct firing	6908	230
VOC	Recommissioning + 1 start+1 shutdown + 240 hrs normal with duct firing + 271.2 hrs normal without duct firing	3386	113
PM10	Recommissioning + 240 hrs normal with duct firing + 278.2 hrs normal without duct firing	8712	290
SOx	Recommissioning + 240 hrs normal with duct firing + 278.2 hrs normal without duct firing	924	31

Note that recommissioning includes 4 starts and 3 shutdowns plus 66.2 hours of downtime.

Change in Monthly Emissions Pre-Modification vs. Post-Modification

	Pre Modification		Post Modification		Change	
Pollutant	Monthly Emissions	30-Day Average	Monthly Emissions	30-Day Average	Monthly Emissions	30-Day Average
NOx	12,418	414	12,374	412	-44	-2
CO	9,243	308	6,908	230	-2,335	-78
VOC	3,744	125	3,386	113	-358	-12
PM10	9,552	318	8,712	290	-840	-28
SOx	1,022	34	924	31	-98	-3

The limits in condition A63.1 will not be changed.

Annual Emissions (PTE)

A. Current PTE Calculation (Pre Modification Emissions)

	# of Events	Hours	NOx	CO	VOC	PM10	SOx	NH3
Start Up	60	360	26400	30000	1800	4244	461	0
Shutdown	60	30	1500	7200	1020	354	38	0
GT Baseload	////////	6932	91364	55595	31749	81728	8873	84362
GT + DB Baseload	////////	1000	17480	10640	6080	16220	1700	16150
Total, lbs		8,322	136,744	103,435	40,649	102,546	11,072	100,512

B. Maximum Annual Emissions with Recommissioning (Post Modification Emissions)

	# of Events	Hours	NOx, lbs	CO, lbs	VOC, lbs	PM10, lbs	SOx, lbs	NH3, lbs
Start Up	56	336	24640	28000	1680	3961	430	0
Shutdown	57	28.5	1425	6840	969	336	36	0
Recommissioning[1]	////////	225.8	4114.87	1439.14	622.68	1480.80	160.26	1415.24
GT Baseload	////////	6731.7	88724	53988	30831	79367	8616	81925
GT + DB Baseload	////////	1000	17480	10640	6080	16220	1700	16150
Total, lbs		8,322	136,384	100,907	40,183	101,365	10,942	99,490

1 - includes 4 SU/3 SD and 66.2 hours of turbine downtime

Change in Emissions Pre Modification vs Post Modification

Pollutant	Pre Modification Annual Emissions	Post Modification Annual Emissions	Change
NOx	136,744	136,384	-360
CO	103,435	100,907	-2,528
VOC	40,649	40,138	-511
PM10	102,546	101,365	-1,181
SOx	11,072	10,942	-130
NH3	100,512	99,490	-1,022

Toxic emission rates from the recommissioning operation will be no greater than the maximum PTE levels because the turbine fuel use rate will not change. Over the course of the 17 days of recommissioning the turbine will use less fuel than it would have if operated at full load since some of the recommissioning activities require low use operation, and there will also be some downtime during the recommissioning. Turbine toxic emissions are shown in Appendix D.

Toxic Emissions

Pollutant	Emission Factor	Hourly Emissions	Annual Emissions
	Lbs/mmscf	Lbs/hr	Lbs/yr
1,3 butadiene	4.39E-04	9.91E-04	6.46
Acetaldehyde	1.80E-01	4.06E-01	2649.42
Acrolein	3.69E-03	8.33E-03	54.31
Benzene	3.33E-03	7.52E-03	49.01
Ethylbenzene	3.26E-02	7.36E-02	479.84
formaldehyde	3.67E-01	8.28E-01	5401.87
Naphthalene	1.33E-03	3.00E-03	19.58
PAH (excluding naphthalene)	9.18E-04	2.07E-03	13.51
propylene oxide	2.96E-02	6.68E-02	435.68
Toluene	1.33E-01	3.00E-01	1957.63
Xylenes	6.53E-02	1.47E-01	961.15
		Total, lbs/yr	12,028
		Total, tpy	6.0

Note: Hourly emission rates are at maximum PTE levels. Annual emissions do not consider recommissioning

6.0 COMPLIANCE RECORD REVIEW

The South Coast AQMD compliance data base shows 3 Notices to Comply and 0 Notices of Violation for this facility in the last 5 years, summarized as follows:

Notice No.	Issue Date	Reason
E27768	9/13/16	Use appropriate status code for CEMS out of control
E27773	5/3/17	Inaccurate QCER submittal
E45021	5/15/19	Submit application to correct ammonia slip monitor description

There are currently no outstanding compliance issues with the facility. The follow up status for the notices are 'in compliance'.

Annual Compliance Certification

The facility filed its latest annual compliance certification report on February 27, 2020. The report indicated no compliance issues with the facility for the compliance year from January 1, 2019 to December 31, 2019.

7.0 CONDITIONS TO BE IMPOSED

The following changes to the permit conditions are recommended:

1. Adjust the allowable limits on recommissioning time, fuel use and NOx emission in Condition A195.2
2. Adjust the allowable limits on recommissioning time, fuel use and CO emission in Condition A195.3
3. Adjust the allowable limits on recommissioning time and fuel use in Condition A195.
4. Add language to Condition C1.5 clarifying the annual operating time limit.
5. Add condition C1.6 specifying the new annual operating time limit.

All other conditions remain unchanged.

GAS TURBINE CONDITIONS

A63.1
The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
CO	9243 LBS IN ANY ONE MONTH
PM10	9552 LBS IN ANY ONE MONTH
VOC	3744 LBS IN ANY ONE MONTH
SOX	1022 LBS IN ANY ONE MONTH

The operator shall calculate the emission limit(s) The operator shall calculate the emission limit(s) by using the monthly fuel use data and the following emissions factors: PM10 with duct firing = 7.98 lb/MMscf, PM10 without duct firing = 6.93 lb/MMscf, VOC with duct firing = 2.69 lb/MMscf, VOC without duct firing = 2.69 lb/MMscf, VOC startups = 30 lb/event, VOC shutdown = 17 lb/event, SOx = 0.75 lb/MMscf.

The operator shall calculate the emission limit(s) for CO, after the CO CEMS certification based upon the readings from the AQMD certified CEMS. In the event the CO CEMS is not operating or the emissions exceed the valid upper range of the analyzer, the emissions shall be calculated in accordance with the approved CEMS plan.

For the purposes of this condition, the limit(s) shall be based on the total combined emissions from equipment D4 (Gas Turbine 1) and D6 (Duct Burner).
[RULE 1303(b)(2)-Offset, 5-10-1996]
[Devices subject to this condition : D4, D6]

A195.2
The 2 PPMV NOX emission limit(s) is averaged over 3 hours at 15 percent oxygen, dry.

The 2.0 PPM NOX emission limit shall not apply during startup, recommissioning, and shutdown periods. Startup time shall not exceed 6 hours per startup per day. NOx emissions during the 6 hours after commencement of a start up shall not exceed 440 lbs. Shutdown time shall not exceed 30 minutes per shutdown per day. NOx emissions during the 30 minutes prior to the conclusion of a shutdown shall not exceed 25 lbs. The operator shall limit the number of start ups to 5 per month.

The operator shall keep records of the date, time and duration as well as minute by minute data (NOx, CO and O2 concentration and fuel flow rate at a minimum) of each startup and shutdown~~.~~

Recommissioning is a one time event that shall not exceed ~~312~~ **159.6** turbine operating hours and ~~402~~ **214** mmscf of fuel use. **Once started, the recommissioning shall be completed within 60 days**. The NOx emissions during recommissioning shall not exceed 198 lbs/hr and ~~5657~~ **4115** total lbs as determined through the use of the certified CEMS. The operator shall keep records of the date and time the turbine is operated during recommissioning, the duration of the operation, the fuel use and the NOx and CO emissions. The operator shall notify AQMD prior to the start of the recommissioning operation and at the conclusion of the recommissioning operation.

[RULE 2005, 5-6-2005]
[Devices subject to this condition: D4, D6]

A195.3
The 2 PPMV CO emission limit(s) is averaged over 1 hour at 15 percent oxygen, dry.

The 2.0 PPM CO emission limit shall not apply during startup, recommissioning, and shutdown periods. Startup time shall not exceed 6 hours per startup per day. Shutdown time shall not exceed 30 minutes per shutdown per day. CO emissions during the 30 minutes prior to the conclusion of a shutdown shall not exceed 120 lbs. The operator shall limit the number of start ups to 5 per month.

The operator shall keep records of the date, time and duration as well as minute by minute data (NOx, CO and O2 concentration and fuel flow rate at a minimum) of each startup and shutdown~~.~~

Recommissioning is a one time event that shall not exceed ~~312~~ **159.6** turbine operating hours and ~~402~~ **214** mmscf of fuel use. **Once started, the recommissioning shall be completed within 60 days**. The CO emissions during recommissioning shall not exceed 84 lbs/hr, 792 lbs in any one day, and ~~1909~~ **1439** lbs total as determined by the certified CEMS. The operator shall keep records of the date and time the turbine is operated during recommissioning, the duration of the operation, the fuel use, and the NOx and CO emissions. The operator shall notify AQMD prior to the start of the recommissioning operation and at the conclusion of the recommissioning operation.
[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]
[Devices subject to this condition: D4, D6]

A195.4
The 2 PPMV VOC emission limit(s) is averaged over 1 hour at 15 percent, dry.

The 2.0 VOC emission limit shall not apply during recommissioning. Recommissioning is a one time event that shall not exceed ~~312~~ **159.6** turbine operating hours and ~~402~~ **214** mmscf of fuel use. **Once started, the recommissioning shall be completed within 60 days**. The operator shall keep records of the date and time the turbine is operated during recommissioning, the duration of the operation, the fuel use and the NOx and CO emissions. The operator shall notify AQMD prior to the start of the recommissioning operation and at the conclusion of the recommissioning operation.
[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]
[Devices subject to this condition: D4, D6]

A327.1
For the purpose of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.
[RULE 475, 10-8-1976; RULE 475, 8-7-1978]
[Devices subject to this condition: D4, D6]

C1.5

The operator shall limit the operating time to no more than 7914 hours in any 12 months

The limit applies only to the 12 month period **beginning from the start of the recommissioning operation in 2020.** The hours counted towards the limit shall include normal operation with and without duct firing and start up and shutdown time but does not include operation during recommissioning.
[RULE 1303(b)(1)-Modeling; RULE 2005]

C1.6
The operator shall limit the operating time to no more than 8096 hours in any 12 months

The limit applies only to the 12 month period beginning from the start of the recommissioning in 2021. The hours counted towards the limit shall include normal operation with and without duct firing and start up and shutdown time but does not include operation during recommissioning.
[RULE 1303(b)(1)-Modeling; RULE 2005]

D29.3
The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method	Averaging Time	Test Location
SOx emissions	AQMD Lab method 307-91	Approved averaging time	Fuel sample
ROG emissions	Approved District Method	1 hour	Outlet of the SCR
PM emissions	EPA Method 201A/District method 5.1	Approved averaging time	Outlet of the SCR

The test shall be conducted at least once every three years. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test. The test shall be conducted 1) when the gas turbine and duct burner are operating simultaneously at 100 percent of max heat input, or as close as practicable, but not less than 90% of max heat input, and 2) when the gas turbine is operating alone at 100% max heat input, or as close as practicable, but not less than 90% of max heat input.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration and/or monthly emissions limit.

For natural gas fired turbines only, an alternative to AQMD Method 25.3 for the purpose of demonstrating compliance with BACT may be the following:

a) Triplicate stack gas samples extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,

b) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and
c) Analysis of Summa canisters per unmodified EPA Method TO-12 (with pre-concentration) or the canister analysis portion of AQMD Method 25.3 with a minimum detection limit of 0.3 ppmv or less and reported to two significant figures. The temperature of the Summa canisters when extracting the samples for analysis shall not be below 70 F

The use of this alternative method for VOC compliance determination does not mean that it is more accurate then unmodified AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval, except for the determination of compliance with the BACT level of 2.0 ppmv ROG calculated as carbon set by CARB for natural gas fired turbines.

Source test results shall be submitted to the AQMD no later than 60 days after the source test was conducted.

Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lbs/hr), and lbs/MM Cubic Feet. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.

Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) and duct burner input (mmbtu/hr) under which the test was conducted.
[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996]
[Devices subject to this condition: D4, D6]

D82.1
The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

The CEMS shall be installed and operated to measure CO concentrations over a 15 minute averaging time period.

The CEMS will convert the actual CO concentrations to mass emission rates (lbs/hr) using the equation below, and record the hourly emission rates on a continuous basis.

CO Emission Rate, lbs/hr = K*Cco*Fd[20.9/(20.9%-%O2 d)][(Qg*HHV)/10E6], where

K	$= 7.267*10^{-8}$ (lbs/scf)/ppm
Cco	= Average of 4 consecutive 15 min. average CO concentrations, ppm
Fd	= 8710 dscf/MMBTU natural gas
%O2, d	= Hourly average % by volume O2 dry, corresponding to Cco
Qg	= Fuel gas usage during the hour, scf/hr
HHV	= Gross high heating value of the fuel gas, BTU/scf

The CEMS shall be installed and operated, in accordance with an AQMD approved Rule 218 CEMS plan application.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996]

[Devices subject to this condition: D4, D6]

D82.2

The operator shall install and maintain a CEMS to measure the following parameters:

NOX concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.

[RULE 2012, 5-6-2005]

[Devices subject to this condition: D4, D6]

E57.1

The operator shall vent this equipment to the CO oxidation and SCR control whenever this equipment is in operation.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 1303(b)(2)-Offset, 5-10-1996; RULE 2005, 5-6-2005]

[Devices subject to this condition: D4, D6]

E193.1

The operator shall construct, operate, and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the Final California Energy Commission Certificate for 01-AFC-6 prepared for this project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D1, D4, D6, C10]

I298.1

This equipment shall not be operated unless the facility holds 132,444 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that at the commencement of each

compliance year after the start of operation, the facility holds 132,444 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other conditions stated in this permit.
[RULE 2005, 5-6-2005]
[Devices subject to this condition: D4]

K67.2
The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

- Natural gas fuel use, hours of operation, date and time of each start up and shutdown, and CEMS minute data during the 6 hours that includes a start up and during the 30 minutes that includes a shutdown

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 2012, 5-6-2005]
[Devices subject to this condition: D4, D6]

DUCT BURNER CONDITIONS

C1.1
The operator shall limit the fuel usage to no more than 555 MM cubic feet per year.
[RULE 1303(b)(1)-Modeling, 5-10-1996; RULE 2005, 5-6-2005]
[Devices subject to this condition : D6]

C1.2
The operator shall limit the fuel usage to no more than 6.66 MM cubic feet per day.
[RULE 1303(b)(1)-Modeling, 5-10-1996]
[Devices subject to this condition : D6]

C1.3
The operator shall limit the fuel usage to no more than 133 MM cubic feet per month.
[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 2005, 5-6-2005]
[Devices subject to this condition : D6]

I298.2
This equipment shall not be operated unless the facility holds 4,300 pounds of NOx RTCs in its allocation account to offset the annual emissions increase for the first year of operation. The RTCs held to satisfy the first year of operation portion of this condition may be transferred only after one year from the initial start of operation. In addition, this equipment shall not be operated

unless the operator demonstrates to the Executive Officer that at the commencement of each compliance year after the start of operation, the facility holds 4,300 pounds of NOx RTCs valid during that compliance year. RTCs held to satisfy the compliance year portion of this condition may be transferred only after the compliance year for which the RTCs are held. If the initial or annual hold amount is partially satisfied by holding RTCs that expire midway through the hold period, those RTCs may be transferred upon their respective expiration dates. This hold amount is in addition to any other amount of RTCs required to be held under other conditions stated in this permit.
[RULE 2005, 5-6-2005]
[Devices subject to this condition: D6]

Appendix A

Criteria Pollutant Calculations

Emission Factors

Pollutant	Emission Factor	Source
NOx	2.0 ppmv	Manufacturer guarantee
CO	2.0 ppmv	Manufacturer guarantee
VOC	2.0 ppmv	Manufacturer guarantee
PM10 (GT)	0.0066 lbs/mmbtu	AP-42
PM10 (Duct Burner)	0.0076 lbs/mmbtu	Applicant
SOx	0.75 lbs/mmscf	Applicant
NH3	5.0 ppm	Manufacturer guarantee

Data

GT rated heat input	=	1,787 mmbtu/hr
Duct burner rated heat input	=	583 mmbtu/hr
F Factor	=	8710 scf/mmbtu @ 0% O2
Fuel HHV	=	1050 btu/cf
NO2 MW	=	46 lbs/lb-mole
CO MW	=	28 lbs/lb-mole
VOC MW	=	16 lbs/lb-mole
Specific Molar Volume	=	385 ft3/lb-mole

GT Calculated exhaust rate	=	1787*8710*(20.9/5.9)	=	55.14 mmscf/hr
DB calculated exhaust rate	=	583*8710*(20.9/5.9)	=	17.99 mmscf/hr
Combined exhaust rate			=	73.13 mmscf/hr
GT calculated fuel use	=	1787/1050	=	1.702 mmscf/hr
DB calculated fuel use	=	583/1050	=	0.555 mmscf/hr
Combined fuel use			=	2.257 mmscf/hr

Emission Rates, Base Load Operation

Pollutant	GT Emission Rate	DB Emission Rate	Total
	lbs/hr	lbs/hr	lbs/hr
NOx	13.18	4.30	17.48
CO	8.02	2.62	10.64
VOC	4.58	1.50	6.08
PM10	11.79	4.43	16.22
SOx	1.28	0.42	1.7
NH3	12.17	3.97	16.15

Sample Calculations

NOx (GT) = [2.0*8710*1787*(20.9/5.9)*46]/385E6
= 13.18 lbs/hr

PM10 (GT) = 0.0066 *1787
= 11.79 lbs/hr

Emission Rates, Start Ups and Shutdowns[1]

Pollutant	Start Up Emission Rate	Total Start Up Emissions (6 hrs/event)	Shutdown Emission Rate	Total Shutdown Emissions (0.5 hrs/event)
	lbs/hr	lbs/event	lbs/hr	lbs/event
NOx	73.33	440	50	25
CO	83.33	500	240	120
VOC	5.00	30	34	17
PM10	11.79	70.74	11.79	5.90
SOx	1.28	7.68	1.28	0.64

1 All start up and shutdown emissions rates provided by the applicant, reference A/N 386305

Emission Rates, Uncontrolled[1]

Pollutant	Uncontrolled GT Emission Rate	Uncontrolled DB Emission Rate	Total
	lbs/hr	lbs/hr	lbs/hr
NOx	63	61	124
CO	73	31	104
VOC	14.1	3	17.1
PM10	11.79	4.43	16.22
SOx	1.28	0.42	1.7

1 All uncontrolled emissions rates provided by the manufacturer, reference A/N 386305

Maximum Emission Rates, Recommissioning[1]

Pollutant	Concentration	Mass Emissions
	Ppm @ 15%	lbs/hr
NOx	55	155.94
CO	27	55.64
VOC	37	43.76

These are the maximum hourly values as provided by the manufacturer and FERCO. Note that the City of Burbank has asked to allow for a contingency and set the limit for NOx at 198 lbs/hr and CO at 84 lbs/hr during the recommissioning.

Maximum Daily Emissions

There will be no increase in maximum daily emissions when comparing the estimates for the maximum emissions that will occur on any given day during recommissioning to the current PTE calculations.

A. Current PTE Calculation (Pre Modification Emissions)

The scenario which results in the highest daily emissions is assumed for each pollutant. For NOx CO, and VOC, maximum daily emissions are calculated assuming 1 start up at the beginning of the day, ½ hour shutdown at the end of the day, and full load operation for the remaining hours of the day, with duct firing for a maximum of 12 hours per day as limited by permit condition. For PM10, and SOx, maximum daily emissions are based on 24 hrs/day base load operation.

Pollutant	Uncontrolled Daily Emissions, lbs/day	Controlled Daily Emissions, lbs/day
NOx	2299.5	747.3
CO	2269.5	791.8
VOC	268.7	145.2
PM10	336.1	336.1
SOx	35.8	35.8
NH3	382.3	382.3

Calculations

NOx uncontrolled = 440 lbs + 124 lbs/hr*12 hrs + 63 lbs/hr*5.5 hrs + 25 lbs = 2299.5 lbs

NOx controlled = 440 lbs + 17.48 lbs/hr*12 hrs + 13.18*5.5 hrs + 25 lbs = 747.3 lbs

CO uncontrolled = 500 lbs + 104 lbs/hr*12 hrs + 73 lbs/hr*5.5 hrs + 120 lbs= 2269.5 lbs

CO controlled = 500 lbs + 10.64 lbs/hr*12 hrs + 8.02 lbs/hr*5.5 hrs + 120 lbs = 791.8 lbs

VOC controlled = 30 lbs + 6.08 lbs/hr*12 hrs + 4.58 lbs/hr*5.5 hrs + 17 lbs = 145.2 lbs

PM10 controlled = 16.22 lbs/hr*12 hrs + 11.79 lbs/hr*12 hrs = 336.1 lbs

B. Maximum Daily Recommissioning Emissions (Post Modification Emissions)

The applicant provided a breakdown of the daily recommissioning activities and the estimated emissions for NOx, CO, and VOC. For PM10 and SOx, the emissions are based on heat input, therefore the days with the highest heat input were used to estimate PM10 and SOx emissions during recommissioning. Refer to Appendix C. There will be no normal operation on any day when there is recommissioning activities.

Pollutant	Recommissioning Daily Emissions, lbs/day
NOx	579.59 (Day 11)
CO	219.00 (Day 11)
VOC	126.23 (Day 11)
PM10	260.50 (Day 8)
SOx	28.19 (Day 8)
NH3	272.48 (Day 8)

Note that the City of Burbank has asked to allow for a contingency and set the limit for CO at 792 lbs/day during the recommissioning.

Calculations

PM10 = 0.0066 lbs/mmbtu* (39469.27 mmbtu) = 260.50 lbs

SOx = 0.75 lbs/mmscf * (39469.27 mmbtu/1050 btu/scf) = 28.19 lbs

NH3 = [5.0 ppm*8710(20.9/5.9)*39469.27 mmbtu*17]/385E6 = 272.48
(all operation on day 11 shows 2 ppm NOx, therefore it can be assumed NH3 injection will be used)

Change in Emissions Pre Modification vs Post Modification

Pollutant	Pre Modification Daily PTE Emissions	Post Modification Daily PTE Emissions	Change
NOx	747.3	579.59	-167.71
CO	791.8	219.00	-572.80
VOC	145.2	126.23	-18.97
PM10	336.1	260.5	-75.60
SOx	35.8	28.19	-7.61
NH3	382.3	272.48	-109.82

Note that the City of Burbank has asked to allow for a contingency and set the limit for CO at 792 lbs/day during the recommissioning. Even with this higher limit, the maximum daily CO emissions during recommissioning are not more than the pre modification PTE.

Monthly Emissions

There will be no increase in maximum monthly emissions when comparing the estimates for the emissions that will occur during the month when recommissioning is performed and normal operation resumes to the current PTE calculations for any pollutant.

A. Current PTE Calculation (Pre Modification Emissions)

The scenario which results in the highest monthly emissions is assumed for each pollutant. For NOx, CO and VOC monthly emissions are based on 5 starts ups per month (and 5 shutdowns), with the remaining hours in base load operation (240 hrs with duct firing, 447.5 hrs without duct firing). For PM10 and SOx, monthly emissions are based on 720 hours in baseload operation (240 hrs with duct firing, 480 hrs without duct firing) and no start ups or shutdowns.

Pollutant	Total Monthly Emissions	30-Day Average Emissions
NOx	12,418	414
CO	9,243	308
VOC	3,744	125
PM10	9,552	318
SOx	1,022	34

Calculations

NOx
440 lbs/start*5 starts + 17.48*240 + 13.18 lbs/hr*447.5 + 25 lbs/shutdown*5 shutdowns
12418 lbs

CO
500 lbs/start*5 starts + 10.64 lbs/hr*240 hrs + 8.02 lbs/hr*447.5 hrs + 120 lbs/shutdown*5 shutdowns
9243 lbs

VOC
30 lbs/start*5 starts + 6.08 lbs/hr*240 hrs + 4.58 lbs/hr*447.5 hrs + 17 lbs/shutdown*5 shutdowns
3744 lbs

SOx
1.7 lbs/hr*240 hrs + 1.28 lbs/hr*480 hrs
1,022 lbs

PM10
16.22*240 hrs + 11.79*480 hrs
9,552 lbs

B. Maximum Monthly Recommissioning Emissions (Post Modification Emissions)

The scenario which results in the highest monthly emissions is assumed for each pollutant. The applicant provided an estimate of 159.6 hours of turbine operation and 66.2 hours of non-operation during recommissioning for a total of 225.8 hours, including 4 starts and 3 shutdowns. In order to estimate maximum monthly emissions of NOx, CO, and VOC, it will be assumed that the turbine will operate the remaining hours in the month at base load with 1 additional start and 2 additional shutdowns (limit of 5 per month). Furthermore, it will be assumed that duct firing will occur at the maximum allowed duration of 240 hours, and the remaining base load operation will be without duct firing. For PM10 and SOx, it will be assumed that the remaining hours after recommissioning are all at base load operation - 240 hours with duct firing and the rest without duct firing, and no start ups or shutdowns.

Operation Type	Duration, hours	NOx	CO	VOC
Recommissioning[1]	159.6	4114.87	1439.14	620.58
Down time during Recommissioning	66.2	0	0	0
Start Up (6 hours per start)	6	440	500	30
Shut Down (0.5 hours per shutdown)	1	50	240	34
Base Load w/o duct firing	271.2	3574.4	2175.0	1242.1
Base Load with duct firing	240	4195.2	2553.6	1459.2
Total	744	12374.47	6907.74	3385.88
30 Day Average		412	230	113

1 - includes 4 SU/3 SD

Calculations

NOx
4114.87 + 440 lbs/start*1 start + 17.48*240 + 13.18 lbs/hr*271.2 + 25 lbs/shutdown*2 shutdown
12374.47 lbs

CO
1439.14 + 500 lbs/start*1 start + 10.64 lbs/hr*240 hrs + 8.02 lbs/hr*271.2 hrs + 120 bs/shutdown*2 shutdown
6907.74 lbs

VOC
620.58+ 30 lbs/start*1 start + 6.08 lbs/hr*240 hrs + 4.58 lbs/hr*271.2 hrs + 17 lbs/shutdown*2 shutdown
3385.88 lbs

Operation Type	Duration, hours	PM10	SOx
Recommissioning	159.6	1538.85	159.40
Down time during Recommissioning	66.2	0	0
Base Load w/o duct firing	278.2	3279.98	356.10
Base Load with duct firing	240	3892.8	408
Total	744	8711.63	923.50
30 Day Average		290	31

PM10
1538.85 + 16.22 lbs/hr*240 hrs + 11.79 lbs/hr*278.2 hrs
8711.63 lbs

SOx
159.40 + 1.7 lbs/hr*240 hrs + 1.28 lbs/hr*278.2 hrs
923.50 lbs

Change in Monthly Emissions Pre-Modification vs. Post-Modification

	Pre Modification		Post Modification		Change	
Pollutant	Monthly Emissions	30-Day Average	Monthly Emissions	30-Day Average	Monthly Emissions	30-Day Average
NOx	12,418	414	12,374	412	-44	-2
CO	9,243	308	6,908	230	-2,335	-78
VOC	3,744	125	3,386	113	-358	-12
PM10	9,552	318	8,712	290	-840	-28
SOx	1,022	34	924	31	-98	-3

Annual Emissions (PTE)

There will be no increase in maximum annual emissions when comparing the estimates for the emissions that will occur during the 12 months when recommissioning is performed and normal operation resumes to the current PTE calculations for any pollutant.

Under this latest application, Burbank is proposing 225.8 hours of recommissioning operation (including 66.2 hours of turbine downtime and 4 SU/3 SD), 6731.7 hrs of baseload operation without duct firing, 1,000 of baseload operation with duct firing, along with 56 start ups and 57 shutdowns outside of recommissioning (364.5 hours), for a total of 8322 hrs/yr.

A. Current PTE Calculation (Pre Modification Emissions)

	# of Events	Hours	NOx, lbs	CO, lbs	VOC, lbs	PM10, lbs	SOx, lbs	NH3, lbs
Start Up	60	360	26400	30000	1800	4244	461	0
Shutdown	60	30	1500	7200	1020	354	38	0
GT Baseload	////////	6932	91364	55595	31749	81728	8873	84362
GT + DB Baseload	////////	1000	17480	10640	6080	16220	1700	16150
Totals		8,322	136,744	103,435	40,649	102,546	11,072	100,512

Calculations

NOx
440 lbs/start*60 starts + 17.48*1000 + 13.18 lbs/hr*6932 + 25 lbs/shutdown*60 shutdowns
136744 lbs

CO
500 lbs/start*60 starts + 10.64 lbs/hr*1000 hrs + 8.02 lbs/hr*6932 hrs + 120 lbs/shutdown*60 shutdowns
103435 lbs

VOC
30 lbs/start*60 starts + 6.08 lbs/hr*1000 hrs + 4.58 lbs/hr*6932 hrs + 17 lbs/shutdown*60 shutdowns
40649 lbs

PM10
70.74 lbs/start*60 starts + 16.22 lbs/hr*1000 hrs + 11.79 lbs/hr*6932 hrs + 5.90 lbs/shutdown*60 shutdowns
102546 lbs

SOx
7.68 lbs/start*60 starts + 1.7 lbs/hr*1000 hrs + 1.28 lbs/hr*6932 hrs + 0.64 lbs/shutdown*60 shutdowns
11072 lbs

NH3
16.15 lbs/hr*1000 hrs + 12.17 lbs/hr*6932 hrs
100,512 lbs

B. Maximum Annual Emissions with Recommissioning (Post Modification Emissions)

	# of Events	Hours	NOx, lbs	CO, Lbs	VOC, lbs	PM10, lbs	SOx, lbs	NH3, lbs
Start Up	56	336	24640	28000	1680	3961	430	0
Shutdown	57	28.5	1425	6840	969	336	36	0
Recommissioning[1]	/////////	225.8	4114.87	1439.14	622.68	1480.80	160.26	1415.24
GT Baseload	/////////	6731.7	88724	53988	30831	79367	8616	81925
GT + DB Baseload	/////////	1000	17480	10640	6080	16220	1700	16150
Totals		8,322	136384	100907	40183	101365	10942	99,490

1 - includes 4 SU/3 SD and 66.2 hours of turbine downtime

Calculations

NOx
4114.87 + 440 lbs/start*56 starts + 17.48*1000 + 13.18 lbs/hr*6731.7 + 25 lbs/shutdown*57 shutdowns
136384 lbs

CO
1439.14 + 500 lbs/start*56 starts + 10.64 lbs/hr*1000 hrs + 8.02 lbs/hr*6731.7 hrs + 120 lbs/shutdown*57 shutdowns
100907 lbs

VOC
622.68 + 30 lbs/start*56 starts + 6.08 lbs/hr*1000 hrs + 4.58 lbs/hr*6731.7 hrs + 17 lbs/shutdown*57 shutdowns
40183 lbs

PM10
1538.85 + 70.74 lbs/start*56 starts + 16.22 lbs/hr*1000 hrs + 11.79 lbs/hr*6731.7 hrs + 5.90 lbs/shutdown*57 shutdowns
101365 lbs

SOx
159.4 + 7.68 lbs/start*56 starts + 1.7 lbs/hr*1000 hrs + 1.28 lbs/hr*6731.5 hrs + 0.64 lbs/shutdown*57 shutdowns
10942 lbs

NH3
[5.0 ppm*8710(20.9/5.9)*205,002.68 mmbtu*17]/385E6 +16.15 lbs/hr*1000 hrs + 12.17 lbs/hr*6731.7 hrs
99490 lbs
(assumes NH3 injection will be used for all recommissioning operation with 2 ppm NOx. From the table in Appendix C, this equates to 205,002.68 mmbtu)

Change in Annual Emissions Pre-Modification vs. Post-Modification

Pollutant	Pre Modification Annual Emissions	Post Modification Annual Emissions	Change
NOx	136,744	136,384	-360
CO	103,435	100,907	-2,528
VOC	40,649	40,138	-511
PM10	102,546	101,365	-1,181
SOx	11,072	10,942	-130
NH3	100,512	99,490	-1,022

Appendix B

GHG Calculations

Out of the six GHG pollutants:

carbon dioxide, CO_2,
methane, CH_4,
nitrous oxide, N_2O
hydrofluorocarbons, HFCs
perfluorocarbons, PFCs
sulfur hexafluoride, SF_6

Only the first 3 are emitted by combustion sources. Sulfur hexafluoride can be emitted by circuit breakers.

The following emission factors and global warming potential (GWP) will be used in the calculations:

GHG Emission Factors

GHG	Emission Factor, natural gas		GWP
	kg/mmbtu	lbs/mmscf	
CO2	53.06	120,017	1.0
CH4	1.0E-03	2.27	25
N2O	1.0E-04	0.227	298

The emission factors in kg/mmbtu are converted to lbs/mmcf assuming the default HHV of 1026 btu/cf from 40 CFR98 Subpart C Table C-1. 1 kg = 2.2046 lbs.

CO2 equivalent (CO2e) is calculated using the following equation:

CO2e = CO2 + 25*CH4 + 298*N2O

Or, using fuel consumption (F):

CO2e = 120,017*F + 2.27*25*F + 0.227*298*F = 120,141*F (in lbs)

CO2e = 60.071*F (in tons)

Post-Modification Turbine Annual Operating Schedule

Event	Duration/yr	Heat Input
Start	360	*(included below)*
Shutdown	30	*(included below)*
100% Load @ w/o DB	6932	1787 (includes start ups/shutdowns)
100% Load with DB	1000	2370
Total	8322	15,454,414

Turbine GHG PTE

GHG	Hourly Tons @ 2370 mmbtu/hr	Annual Tons @ 15,454,414 mmbtu/yr
CO2	138.6	903,898
CH4	2.61E-03	17
N2O	2.61E-04	1.7
Total Mass	138.6	903,917
CO2e	138.7	904,830

Estimated lbs of CO2 per MWH (based on PTE, not actual operating conditions)

Heat Rate no duct firing= (1787E6 btu/hr)/(181,100 + 85,000)kW = 6715.5 btu/kWh
Heat Rate with duct firing (2370E6 btu/hr)/(323,100 kW) = 7335.2 btu/kWh

Overall net heat rate = [(Heat Rate no duct firing * # of Hours no duct firing) + (Heat Rate with duct firing* # of Hours with duct firing)] /Total Annual Hours of Operation

Overall net heat rate = (6715.5 btu/kWh*7322 hrs + 7335.2 btu/Kwh*1000 hrs)/(8322) = 6790.0 btu/kWh

6,790.0 btu/kWh * 1000 kWh/MWh * 1*10-6 MMBtu/Btu * 53.06 kg CO2/MMBtu-HHV * 2.205 lb/kg = 793.8 lb CO2/MWH

794.4 lb CO2/netMWH @ HHV

Past Actual GHG Emissions

Based on the previous 24 month annual average heat input of 8,836,018.6 mmbtu taken from Appendix G

Pollutant	Average Annual Emissions Previous 24 Months	
	lbs/yr	tons/yr
CO_2	1033.01E+06	516,506
CH_4	19,483	9.74
N_2O	1,948	0.974
Total Mass	1033.03E+06	516,516
CO_2e	1034.02E+06	517,012

Appendix C

Recommissioning Emissions

After installation of the new combustor, the turbine will undergo testing to ensure it can operate at the higher turndown ratios and still maintain compliance with its emission limits.

The recommissioning will take approximately 11 days and 159.6 operating hours.

Table C.1 Summary of Recommissioning Activities and Emissions

Day	Activity	CT Load (%)	Duration (hours)	Fuel Use	Total Emissions lbs			Outlet PPM
				MMBTU	NOx	CO	VOC	NOx
1	Cold Start	10	4	2256.10	394.84	140.48	75.44	51
2	(con'd)	10	2.4	1353.66	236.90	84.29	45.26	51
	Checkout/Mapping	25	0.2	165.22	31.19	6.94	3.12	55
	Checkout/Mapping	35	0.2	198.42	2.39	11.13	8.75	3.5
	Checkout/Mapping	50	1	1204.41	8.44	3.35	0.18	2
	Checkout/Mapping	90	1.4	2425.62	17.58	4.16	0.41	2
	Part Load Mapping	50	2.8	3372.34	23.63	9.38	0.50	2
	Part Load Mapping	90	12	20790.98	150.72	35.64	3.48	2
	Day 2 Total		20	29510.65	470.85	154.89	61.70	//////////
3	Shutdown/Warm Start	10	3	1692.08	296.13	105.36	56.58	51
	Mapping/checkout	25	0.4	330.45	62.38	13.88	6.24	55
	Mapping/checkout	35	0.4	396.83	4.77	22.26	17.50	3.5
	Part Load Mapping	50	2	2408.82	16.88	6.70	0.36	2
	Part/Base/Peak Map	90	10.2	17672.33	128.11	30.29	2.96	2
	Day 3 Total		16	22500.50	508.27	178.49	83.64	//////////
4	(con'd)	90	1.8	3118.65	22.61	5.35	0.52	2
	Part Load Mapping	50	6	7226.45	50.64	20.10	1.08	2
	Part/Base/Peak Map	90	6	10395.49	75.36	17.82	1.74	2
	Turndown Tuning	50	9	10839.68	75.96	30.15	1.62	2
	Turndown Tuning	90	1.2	2079.09	15.07	3.56	0.35	2
	Day 4 Total		24	33659.36	239.64	76.98	5.31	//////////
5	(con'd)	90	1.8	3118.65	22.61	5.35	0.52	2
	Autotune Validation	90	12	20790.98	150.72	35.64	3.48	2
	Autotune Validation	50	10.2	12284.97	86.09	34.17	1.84	2
	Day 5 Total		24	36194.60	259.42	75.16	5.84	//////////
6	(con'd)	50	1.8	2167.94	15.19	6.03	0.32	2
	Shutdown/Warm Start	10	3	1692.08	296.13	105.36	56.58	51
	Mapping	25	1	826.12	155.94	34.69	15.61	55
	Day 6 Total		5.8	4686.13	467.26	146.08	72.51	//////////
7	(con'd)	25	1	826.12	155.94	34.69	15.61	55
	Mapping	35	2	1984.15	23.86	111.30	87.52	3.5
	Autotune	50	3	3613.23	25.32	10.05	0.54	2
	Autotune/AT Mode	90	2	3465.16	25.12	5.94	0.58	2
	Final Autotune	50	2	2408.82	16.88	6.70	0.36	2

	Final Autotune	90	2	3465.16	25.12	5.94	0.58	2
	Overnight Run	50	12	20790.98	150.72	35.64	3.12	2
	Day 7 Total		24	36553.62	422.96	210.26	108.31	/////////
8	(con'd)	50	12	20790.98	150.72	35.64	3.12	2
	Final Autotune	90	8	13860.65	100.48	23.76	2.32	2
	Fast Ramp	50	4	4817.63	33.76	13.40	0.72	2
	Day 8 Total		24	39469.27	284.96	72.80	6.16	/////////
9	(con'd)	50	2	2408.82	16.88	6.70	0.36	2
	Fast Ramp	90	6	10395.49	75.36	17.82	1.74	2
	Day 9 Total		8	11599.96	92.24	24.52	2.10	/////////
10	Shutdown/Cold Start	10	4	2256.10	394.84	140.48	75.44	51
11	(con'd)	10	2.4	1353.66	236.90	84.29	45.26	51
	Mapping contingency	25	2	1652.23	311.88	69.38	31.22	55
	Mapping contingency	35	1	992.08	11.93	55.65	43.76	3.5
	Load to Base	25	0.1	82.61	15.59	3.47	1.56	55
	Load to Base	35	0.1	99.21	1.19	5.57	4.38	3.5
	Load to Base	50	0.1	120.45	0.84	0.34	0.02	2
	Load to Base	90	0.1	173.26	1.26	0.30	0.03	2
	Day 11 Total		5.8	4473.50	579.59	219.00	126.23	/////////
	Overall Totals		159.6	224,364.15	4114.87	1439.14	622.68	/////////

Fuel use can be converted to mmscf by using a heating value of 1050 btu/scf

Fuel Use Rates, Exhaust Temperatures, Load Ranges, and Emission Rates:

Nominal Load %	Min Load %	Max Load %	Nominal Exhaust Temp °F	Fuel Use Rate HHV, mmbtu/hr	NOx, lbs/hr	CO, lbs/hr	VOC, lbs/hr
10	0	20	907	564.03	98.71	35.12	18.86
25	10	25	1146	826.12	155.94	34.69	15.61
35	15	35	1200	992.08	11.93	55.65	43.76
50	20	50	1189	1204.41	8.44	3.35	0.18
90	30	110	1110	1732.58	12.56	2.97	0.29

Fuel use can be converted to mmscf by using a heating value of 1050 btu/scf
Note that the estimated emissions during recommissioning are provided by GE (out of the combustor) and FERCO (out of the stack). However, the applicant has asked to allow for a contingency and set the limit for NOx at 198 lbs/hr and CO at 84 lbs/hr and 792 lbs/day during the recommissioning.

Expected Pollutant Concentrations During the Recommissioning Operation

Nominal Load %	O2 % Dry	NOx Concentration, ppm @ 15% O2	CO Concentration, ppm @ 15% O2	VOC Concentration, ppm @ 15% O2
10	16.96	51	30.0	28.1
25	15.03	55	20.0	15.7
35	14.36	3.5	26.8	36.8
50	13.84	2	1.3	0.13
90	13.29	2	0.8	0.14

The CO CEMS is certified to operate on a dual range, 0-10 ppm and 0-200 ppm. The valid range is 10-95% of full span, therefore the minimum CO concentration that can be measured at the low range is 1 ppm, and the minimum concentration that can be measured at the high range is 20 ppm. The CO CEMS will switch to the high range when emission are at 9.5 ppm or higher. The CO emissions estimate for the recommissioning takes into account these minimum concentrations, i.e., any CO concentrations assumed to be under 1 ppm were adjusted to 1 ppm, and any CO concentrations assumed to be above 9.5 ppm and below 20 ppm were adjusted to 20 ppm.

Appendix D

Toxic Emissions

Toxic emissions estimates are based on emission factors from USEPA AP-42 Table 3.1-3, except for Acetaldehyde, Formaldehyde, Benzene, and Acrolein emission factors which are from the Background document for AP-42 Section 3.1, Table 3.4-1 for a natural gas turbine with a CO catalyst.

The following data was used:

Fuel HHV	=	1,050 btu/cf		
Gas Turbine Fuel Use	=	1,787 mmbtu/hr/1050 btu/cf	=	1.702 mmscf/hr
Duct Burner Fuel Use	=	583 mmbtu/hr/1050 btu/cf	=	0.555 mmscf/hr
Total Fuel Use	=	2.257 mmscf/hr		
Hrs/yr with Duct Firing	=	1000		
Annual Fuel Use with DF	=	2.257*1000	=	2257 mmscf
Hrs/yr no Duct Firing	=	7322 (includes start ups and shutdowns)		
Annual Fuel Use No DF	=	1.702*7322	=	12462 mmscf
Total Annual Fuel Use	=	14,719 mmscf		

Pollutant	Emission Factor	Hourly Emissions	Annual Emissions
	Lbs/mmscf	Lbs/hr	Lbs/yr
1,3 butadiene	4.39E-04	9.91E-04	6.46
acetaldehyde	1.80E-01	4.06E-01	2649.42
acrolein	3.69E-03	8.33E-03	54.31
benzene	3.33E-03	7.52E-03	49.01
ethylbenzene	3.26E-02	7.36E-02	479.84
formaldehyde	3.67E-01	8.28E-01	5401.87
naphthalene	1.33E-03	3.00E-03	19.58
PAH (excluding naphthalene)	9.18E-04	2.07E-03	13.51
propylene oxide	2.96E-02	6.68E-02	435.68
toluene	1.33E-01	3.00E-01	1957.63
xylenes	6.53E-02	1.47E-01	961.15
		Total, lbs/yr	12,028
		Total, tpy	6.0

Note that under A/N 386305 and subsequent application 464716, toxic emission for the gas turbine were based on AP-42 Table 3.1-3, dated 4/00, except for Formaldehyde which was based on a Sims Roy memo to Docket A-95-51 dated 8/2/01, and Hexane, Propylene, and PAHs which were based on the CATEF II database (CARB 2001). Factors for the duct burner were based on Ventura County AB-2588 for natural gas fired equipment > 100 mmbtu/hr dated 8/24/95.

Appendix E

Major Source Determinations

//PSD//

For purposes of PSD, the major source threshold for a fossil fuel fired steam electric plant with a heat input greater than 250 mmbtu/hr is the actual or potential to emit 100 tpy of any regulated NSR pollutant less any emission reduction from shutdown or modification. If the existing source exceeds 100 tpy on a pollutant specific basis, it is deemed to be an existing major source. In that case, if the modification to the existing major source is a major modification, the new source is subject to PSD. In the case of an existing minor source, if the new source 'in and of itself' is major, ie > 100 tpy, (without netting), PSD is applicable. For GHG emissions, the major source threshold is EITHER 75,000 tpy CO2e AND a net increase greater than 0 tpy total GHG mass if the source is subject to PSD for another regulated pollutant ('anyway' sources). Or, for an existing major source of GHG's, the modification is major if it results in an increase of 75,000 tpy CO2e AND a net increase of GHG mass greater than 0 tpy. For an existing minor source of GHG's, the modification is major if it results in an increase of 100,000 tpy CO2e AND a net increase greater than 100 tpy GHG.

//Title V//

For Part 70 (Title V), the major source thresholds for a particular pollutant depends on the attainment status of the pollutant. For the federal standards, NO_2, SO_2, CO, and PM10 are in attainment, while PM2.5 is serious non-attainment and ozone is extreme non-attainment. For the state standards, PM10, PM2.5, and ozone are non-attainment, while NO2 and CO are attainment. For the South Coast Air Basin (SOCAB) the threshold levels are as follows:

Pollutant	SOCAB Major Source Thresholds (tpy)
VOC	10
NOx	10
SOx	100
CO	100
PM-10	100
PM-2.5	70
Single HAP	10
Combination of HAPS	25

Facility Annual PTE

Pollutant	Turbine PTE, tpy	Major Source?	
		PSD	Title V
NOx	68.37	N	Y
CO	51.72	N	N
VOC	20.32	N	Y
PM10/2.5	51.27	N	N
SO2	5.54	N	N
CO2e	517,012	Y	/////////
HAPs	6.0	////////	N

Note that emissions from the storage silos are not included because they are negligible.

//CAM//

The CAM Regulations of 40CFR 64 apply on a pollutant specific basis to units at major sources required to obtain a part 70 or 71 permit which have pre-control potential to emit (PTE) emission levels exceeding the major source thresholds.

Turbine Emission Rates

	NOx	CO	VOC	PM10	SOx
Uncontrolled GT emission rate (lbs/hr)	63	73	14.1	11.79	1.28
Uncontrolled GT + DB emission rate (lbs/hr)	124	104	17.1	16.22	1.7
Start (lbs/hr)	73.33	83.33	5.00	11.79	1.28
Shutdown (lbs/hr)	50	240	34	11.79	1.28

1 All uncontrolled emissions rates provided by the manufacturer, reference A/N 386305

Annual Operating Schedule

Event	# of Events	Hours
Start	60	360
Shutdown	60	30
GT Baseload	//////////////	6932
GT + DB Baseload	//////////////	1000
	Total	8322

Turbine Annual PTE, Pre Control

Pollutant	Annual Uncontrolled Emissions		Threshold	Major Source?
	Lbs/yr	Tpy	Tpy	
NOx	588614.8	294.3	10	Y
CO	647234.8	323.6	100	Y
VOC	117661.2	58.8	10	Y
PM10	102546.4	51.3	100	N
PM2.5	102546.4	51.3	70	N
SOx	11072.2	5.5	100	N

Appendix F

NSR Offset History

The turbine was initially permitted in 2003 under A/N 386305, and offsets were provided in the form of external ERCs and purchases from the Priority Reserve under Rule 1309.1, as follows:

Pollutant	ERC, lbs/day	Priority Reserve, lbs/day
CO	319*	0
PM10	336	336
VOC	145*	0
SOx	14*	23

** Includes 1.2 to 1.0 factor*

The NOx RTC's for the first year of operation were estimated to be 127,455 lbs/yr.[1]

Burbank requested an increase in allowable start up time from 4 hours to 6 hours, and took a reduction in monthly allowable duct firing operation from 240 hrs/month to 200 hrs/month under A/N 474716. This resulted in no net emissions increases and therefore, no offsets were required. The annual NOx emissions changed under this application due to the both the number of starts ups and shutdowns being changed (from 52 to 36) and the NOx emission factors being changed. The annual NOx was calculated as 132,962 (later corrected to 130,723 lbs under A/N 575368).

Burbank requested an increase in the number of allowable start ups from 3 per month and 36 per year to 5 per month and 60 per year, and an increase in the monthly allowable duct firing operation from 200 hrs/month to 240 hrs/month under A/N 575368. This resulted in an increase in 1,243 lbs/month (41 lbs/day) CO and 94 lbs/month (3 lbs/day) VOC. Offsets were provided in the form of external ERCs, as follows:

Pollutant	ERC, lbs/day
VOC	4*
CO	0

** Includes 1.2 to 1.0 factor*

Note that CO was an attainment pollutant at the time of this modification, therefore no offsets were required. The annual NOx emissions changed under this application due to the number of starts ups and shutdowns being changed. The annual NOx was calculated as 136,744.

The unit is limited to the following monthly emissions under condition A63.1

Pollutant	Monthly Limit
CO	9243

[1] *The annual NOx calculation was based on 52 start ups (4290 lbs) and 52 shutdowns (2600 lbs), commissioning hours of operation (14,141 lbs), and base load operation (106424 lbs). The original permit did not limit the number of start ups.*

PM10	9552
VOC	3744
SOx	1022

The original permit was issued with a monthly PM10 limit of 10,080 lbs/month and a monthly SOx limit of 1,039 lbs/month under Condition A63.1. Emissions were calculated assuming an 18 lbs/hr emission rate for operation of the turbine with duct firing, and a 12 lbs/hr emission rate for operation of the turbine without duct firing. Under A/N 474716, the applicant proposed emission rates of 16.22 lbs/hr for operation of the turbine with duct firing, and 11.79 lbs/hr for operation of the turbine without duct firing. Therefore, the monthly emissions were recalculated and adjusted in condition A63.1 to reflect these new emission factors (refer to A/N 575368 for further discussion).

Appendix G

Past Actual Emissions

Past actual emissions can be used to determine the applicability of PSD (new PTE vs existing actual emissions), in the case of a PSD major source and for purposes of PSD for GHG emissions. The following data and calculations are used to estimate past actual GHG emissions in Appendix E.

Emission Factors for Determination of Past Actual Emissions

Data:

Heat input no duct firing = 1787 mmbtu/hr
Heat input with duct firing = 2370 mmbtu/hr

Hourly emission rates are taken from Appendix A

Emission Rates, Base Load Operation

Pollutant	No duct firing		With duct firing	
	lbs/hr	lbs/mmbtu	lbs/hr	lbs/mmbtu
NOx	13.18	7.38E-03	17.48	7.38E-03
CO	8.02	4.49E-03	10.64	4.49E-03
VOC	4.58	2.56E-03	6.08	2.57E-03
PM10	11.79	6.60E-03	16.22	6.84E-03
SOx	1.28	7.16E-04	1.7	7.17E-04
NH3	12.17	6.81E-03	16.15	6.81E-03

Emission Factors Used in the Calculations

Pollutant	Emission Factor, lbs/mmbtu
NOx	7.38E-03
CO	4.49E-03
VOC	2.56E-03
PM10	6.60E-03
SOx	0.681E-03

Emission factors are essentially the same with or without DF

Heat Input Data(1)

Year	Month	Heat Input, mmbtu
2018	October	1039802.4
	November	894555.1
	December	932858.1
	Total	2867215.6

2019	January	1011560.8
	February	716993.5
	March	1016961.1
	April	973442.1
	May	902239.0
	June	981693.7
	July	1059268
	August	906231.4
	September	1012780
	October	1033379.8
	November	912661.1
	December	1001753
	Total	11528963.5
2020	January	867749.3
	February	45073.8
	March	733014.1
	April	817157.8
	May	948564.3
	June	861665.4
	July	1022766.4
	August	1026228.6
	September	846310.3
	Total	7168530.0
Average Annual Heat Input Previous 24 Months		10,782,354.6
Average Capacity Factor(2)		68.9%

(1) As reported under the Acid Rain program
(2) Capacity factor based on 7322 hrs/yr at 1787 mmbtu/hr and 1000 hrs/yr at 2570 mmbtu/hr

Pollutant	Average Annual Emissions Previous 24 Months	
	lbs/yr	tons/yr
NOx	79574	40
CO	48413	24
VOC	27603	14
PM10	71164	36
SOx	7343	4

Pollutant	Highest Monthly Emissions Previous 24 Months (October 2018)
	lbs/month
NOx	7674
CO	4669
VOC	2662
PM10	6863
SOx	708

The facility also reported the following hours of operation(1).

Year	Month	Hours of Operation
2018	October	744
	November	660.3
	December	714.7
	Total	2119.0
2019	January	744
	February	516.1
	March	744
	April	720
	May	684
	June	720
	July	744
	August	638.33
	September	720
	October	743.76
	November	660.45
	December	744
	Total	8378.64
2019	January	654.76
	February	43.49
	March	560.87
	April	624.02
	May	744
	June	660.32
	July	744
	August	743.98
	September	614.78
	Total	5390.22

(1) As reported under the Acid Rain program

Appendix H

NSPS Calculation

The applicable limit is based on the §60.332 (a)(1) equation as follows:

$$STD = 0.0075\frac{14.4}{Y} + F$$

Where:

STD	=	allowable NOx emissions in percent volume at 15%, dry
Y	=	manufacturer's rated heat rate at manufacturer's rated load in KJ/watt-hr
F	=	0 for fuel with nitrogen content < 0.015%w
F	=	0.04N for fuel with nitrogen content between 0.015 and 0.1%w
Y	=	(1,767,000,000 btu/hr ÷ 181,100,000W) X (1055 joules/btu) X (KJ/1000 J)
Y	=	10.29 KJ/Watt-hr

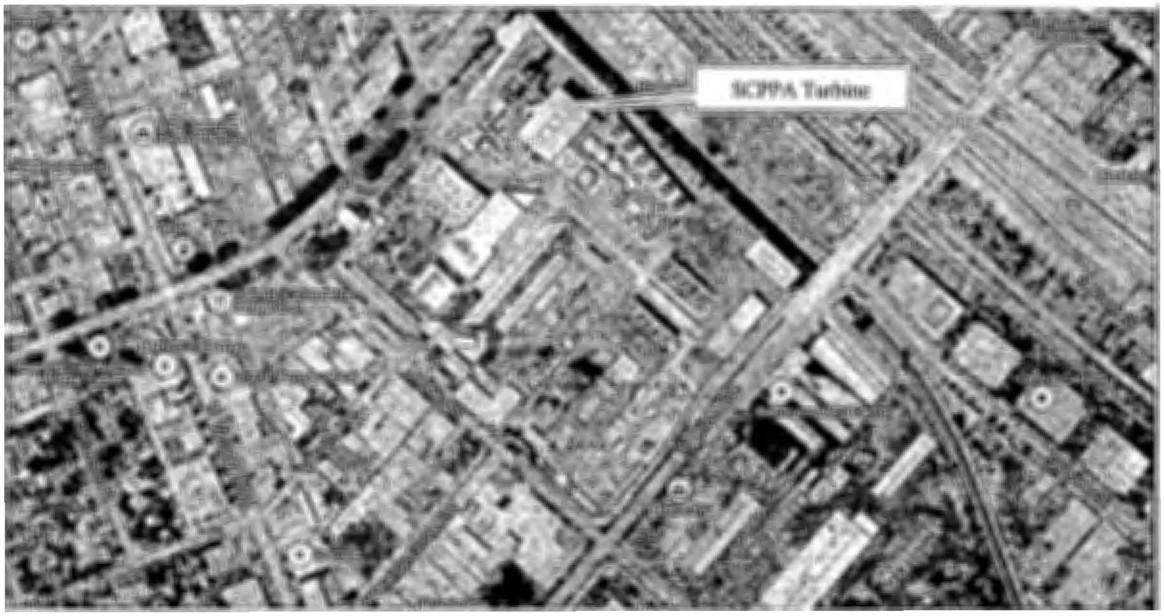
For natural gas, nitrogen can be assumed to be <0.015%w, therefore:

STD	=	0.0075(14.4/10.29) + 0	=	0.01050
			=	105.0 ppm

Note that the STD is being changed from the original permit application (A/N 386305) where Y was determined to be 9.48 kj/W-hr based on the LHV. However, in accordance with §60.332 the LHV is only used to calculate Y in cases where the turbine's actual measured heat rate at peak load is used in the equation. When using the turbines rated load in the calculation, HHV should be used.

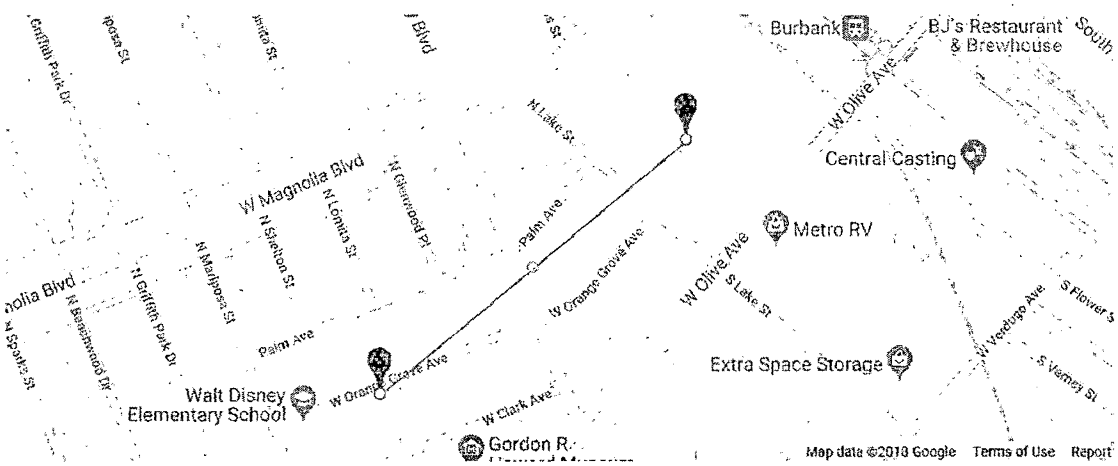
Appendix I

Equipment Location



Appendix J

Approximate Distance to Nearest School



Distance 1880.569 Feet

Autopan ?