DOCKETED	
Docket Number:	01-AFC-25C
Project Title:	Malburg Generating Station-Compliance
TN #:	227500
Document Title:	SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT TURBINE UPGRADE ENGINEERING EVALUATION AND PROPOSED FACILITY PERMIT
Description:	N/A
Filer:	Anwar Ali
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	4/4/2019 1:26:22 PM
Docketed Date:	4/4/2019

BICENT (CALIFORNIA) MALBURG LLC
4963 S SOTO ST
VERNON, CA 90058-2911

FACILITY ID: 155474

LOCATION ADDRESS: Same

EVALUATION FOR PERMITS TO CONSTRUCT FOR MODIFICATION OF TURBINES TO ADD SIEMENS A+ TURBINE UPGRADE & INCREASE OPERATING SCHEDULE

EQUIPMENT DESCRIPTION

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

This evaluation is for Permits to Construct to modify the two combined-cycle turbines to install the Siemens A+ Turbine Upgrade, increase the operating schedule, and implement other emissions-related revisions. The Permits to Construct for the turbines will be added to Section H. The revisions shown below are to the prior facility permit (all equipment were in Section D) that was issued for the Title V renewal, A/N 561415, on 11/3/15.

As applications were <u>not</u> required for the CO/SCR catalyst systems, the turbines in Section H will be connected to the CO/SCR catalyst systems in Section D in the facility permit program.

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 3: ELECTRIC GENERATION, GAS TURBINE (MGS POWER ISLAND NO. 1)					
GAS TURBINE, NO. 1, NATURAL GAS, ~~ALSTOM~~ **SIEMENS**, MODEL ~~GTX100~~ **SGT-800 WITH A-PLUS UPGRADE**, ~~454.05~~ **491.76** MMBTU/HR AT 38 DEGREES F **(**HHV**)** WITH A/N: ~~517249~~ **598922** GENERATOR, CTG NO. 1, ~~44.2~~ **48.4** MW **GROSS AT 38 F** HEAT EXCHANGER, HRSG NO. 1	D27 (B28) (B29)	C32 C33	NOX: MAJOR SOURCE**	CO: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; CO: 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982];	~~A63.3~~ **A63.4**, ~~A99.3~~ **A99.6**, ~~A99.4~~ **A99.7**, ~~A99.5~~ **A99.8**, ~~A195.1~~ **A195.5**, ~~A195.2~~ **A195.6**, ~~A195.3~~ **A195.7**, A327.1, ~~C1.4~~ **C1.6**, D12.3, ~~D29.2~~ **D29.4**, ~~**D29.3**~~ **D29.5** D82.1, D82.2, E57.1, **E193.2,**

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
GENERATOR, STEAM TURBINE GENERATOR (STG), **55 MW GROSS,** COMMON WITH HRSG NO. 2	(B30)			**NOX: (9) [40 CFR 72 – Acid Rain Provisions, 11-24-1997**]; 2 PPMV NATURAL GAS (4) [RULE 2005, ~~6-3-2011~~ **12-4-2015**]; ~~NOX: 110 PPMV NATURAL GAS (8) [40 CFR 60 Subpart GG, 2-27-2014~~] **NOx: 42 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006];** PM**10**: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM**10**: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; **PM10: 3.386 LB/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002];** PM**10**: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978] SO2: (9) [40 CFR 72-Acid Rain Provisions, 11-24-1997]; ~~SOX: 150 PPMV NATURAL GAS (8) [40 CFR 60 Subpart GG, 2-27-2014]~~ **SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40 CFR 60**	**H23.2, H23.3,** I298.1, K40.1

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				SUBPART KKKK, 7-6-2006]; VOC: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
BURNER, DUCT BURNER, NATURAL GAS, SERVING HRSG NO. 1, 81.2 MMBTU/HR A/N: ~~517249~~ **598922**	D31	C32 C33	NOX: MAJOR SOURCE**	CO: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**; RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; CO: 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982]; **NOX: (9) [40 CFR 72 – Acid Rain Provisions, 11-24-1997**]; 2 PPMV NATURAL GAS (4) [RULE 2005, ~~6-3-2011~~ **12-4-2015**]; ~~NOX: 110 PPMV NATURAL GAS (8) [40 CFR 60 Subpart GG, 2-27-2014~~] **NOx: 42 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006];** PM**10**: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM**10**: 0.1 GRAINS/SCF (5)	~~A63.3~~ **A63.4**, ~~A99.3~~ **A99.6**, ~~A99.4~~ **A99.7**, ~~A99.5~~ **A99.8**, ~~A195.1~~ **A195.5**, ~~A195.2~~ **A195.6**, ~~A195.3~~ **A195.7** A327.1, ~~C1.4~~ **C1.6**, D12.3, ~~D29.2~~ **D29.4**, ~~**D29.3**~~ **D29.5**, D82.1, D82.2, E57.1, **E193.2, H23.2, H23.3,** I298.2, K40.1, K67.4

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				[RULE 409, 8-7-1981]; **PM10: 3.386 LB/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002];** PM**10**: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978] SO2: (9) [40 CFR 72-Acid Rain Provisions, 11-24-1997]; ~~SOX: 150 PPMV NATURAL GAS (8) [40 CFR 60 Subpart GG, 2-27-2014]~~ **SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006];** VOC: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
STACK, NO. 1, SERVING TURBINE NO. 1, HEIGHT: 110 FT; DIAMETER: 12 FT A/N: ~~517249~~ **598922**	D35				
System 4: ELECTRIC GENERATION, GAS TURBINE (MGS POWER ISLAND No. 2)					
GAS TURBINE, NO. 2, NATURAL GAS, ~~ALSTOM~~ **SIEMENS**, MODEL ~~GTX100~~ **SGT-800 WITH A-PLUS UPGRADE**, ~~454.05~~ **491.76** MMBTU/HR AT 38 DEGREES F **(**HHV**)** WITH A/N: ~~517250~~ **598923**	D36	C40 C41	NOX: MAJOR SOURCE**	CO: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**; RULE 1703(a)(2) - PSD-BACT, 10-7-**	~~A63.3~~ **A63.4**, ~~A99.3~~ **A99.6**, ~~A99.4~~ **A99.7**, ~~A99.5~~ **A99.8**, ~~A195.1~~ **A195.5**, ~~A195.2~~ **A195.6**, ~~A195.3~~ **A195.7**

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
GENERATOR, CTG NO. 2, ~~44.2~~ **48.4** MW **GROSS AT 38 F** HEAT EXCHANGER, HRSG NO. 2 GENERATOR, STEAM TURBINE GENERATOR (STG), 55 MW **GROSS,** COMMON WITH HRSG NO. 1	(B37) (B38) (B50)			**1988**]; CO: 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982]; **NOX: (9) [40 CFR 72 – Acid Rain Provisions, 11-24-1997**]; 2 PPMV NATURAL GAS (4) [RULE 2005, ~~6-3-2011~~ **12-4-2015**]; ~~NOX: 110 PPMV NATURAL GAS (8) [40 CFR 60 Subpart GG, 2-27-2014~~] **NOx: 42 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006];** PM**10**: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM**10**: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; **PM10: 3.386 LB/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002];** PM**10**: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978] SO2: (9) [40 CFR 72-Acid Rain Provisions, 11-24-1997]; ~~SOX: 150 PPMV NATURAL GAS (8) [40 CFR 60~~	A327.1, ~~C1.4~~ **C1.6**, D12.3, ~~D29.2~~ **D29.4**, ~~**D29.3**~~ **D29.5**, D82.1, D82.2, E57.1, **E193.2, H23.2, H23.3,** I298.3, K40.1

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				~~Subpart GG, 2-27-2014]~~ **SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006];** VOC: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
BURNER, DUCT BURNER, NATURAL GAS, SERVING HRSG NO. 2, 81.2 MMBTU/HR A/N: ~~517250~~ **598923**	D39	C40 C41	NOX: MAJOR SOURCE**	CO: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**; RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]; CO: 2000 PPMV NATURAL GAS (5) [RULE 407, 4-2-1982]; **NOX: (9) [40 CFR 72 – Acid Rain Provisions, 11-24-1997**]; 2 PPMV NATURAL GAS (4) [RULE 2005, ~~6-3-2011~~ **12-4-2015**]; ~~NOX: 110 PPMV NATURAL GAS (8) [40 CFR 60 Subpart GG, 2-27-2014~~] **NOx: 42 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006];**	~~A63.3~~ **A63.4**, ~~A99.3~~ **A99.6**, ~~A99.4~~ **A99.7**, ~~A99.5~~ **A99.8**, ~~A195.1~~ **A195.5**, ~~A195.2~~ **A195.6**, ~~A195.3~~ **A195.7** A327.1, ~~C1.4~~ **C1.6**, D12.3, ~~D29.2~~ **D29.4**, ~~**D29.3**~~ **D29.5**, D82.1, D82.2, E57.1, **E193.2, H23.2, H23.3,** I298.4, K40.1, K67.4

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				PM**10**: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM**10**: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; **PM10: 3.386 LB/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002];** PM**10**: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978] SO2: (9) [40 CFR 72-Acid Rain Provisions, 11-24-1997]; ~~SOX: 150 PPMV NATURAL GAS (8) [40 CFR 60 Subpart GG, 2-27-2014]~~ **SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006];** VOC: 2 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	
STACK, NO. 2, SERVING TURBINE NO. 2, HEIGHT: 110 FT; DIAMETER: 12 FT A/N: ~~517250~~ **598923**	D43				

(1) Denotes RECLAIM emission factor
(2) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit
(4) Denotes BACT emissions limit
(5)(5A)(5B) Denotes command & control emission limit
(6) Denotes air toxic control rule limit

(7) Denotes NSR applicability limit (8)(8A)(8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)

(9) See App B for Emission Limits (10) See Section J for NESHAP/MACT requirements

** Refer to Section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

DEVICE CONDITIONS

Note: **For Section D (Permits to Operate), the conditions will retain the same condition numbers as in the current permit. For the new Section H (Permits to Construct), the revised conditions will have new condition numbers. The reason is that the Facility Permit Program will not allow a permit condition to have different requirements in Section H than in Section D.**

TURBINES

~~A63.3~~ **A63.4** The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
CO	Less than 7633 LBS IN ANY ONE MONTH
PM10	Less than 4876 LBS IN ANY ONE MONTH
PM2.5	**Less than 4876 LBS IN ANY ONE MONTH**
VOC	Less than 3236 LBS IN ANY ONE MONTH
SOX	Less than ~~214~~ **227** LBS IN ANY ONE MONTH

For the purposes of this condition, the limit(s) shall be based on the total combined emissions from equipment D27, D36 (both gas turbines) and D31, D39 (both duct burners).

The operator shall calculate the emissions for CO, after the CO CEMS certification, based on the readings from the certified CO CEMS. In the event 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 normal operation, ~~T~~ **t**he operator shall calculate the emissions by using monthly fuel use data **for normal operation** and the following emission factors: PM10**/PM2.5** ~~7.397~~ **6.014** lbs/mmscf, VOC ~~1.63~~ **1.54** lbs/mmscf and SOx 0.28 lb/mmscf**.**

The operator shall calculate the emissions by using monthly fuel use data and the following emission factors: PM10 7.397 lbs/mmscf, VOC 1.63 lbs/mmscf and SOx 0.28 lb/mmscf.

For the commissioning of the Siemens A-Plus Turbine Upgrade project, the operator shall calculate the emissions by using monthly fuel use data for the commissioning and the following emission factors: PM10/PM2.5 6.014 lbs/mmscf, VOC 22.26 lbs/mmscf and SOx 0.6 lb/mmscf.

For a month during which both commissioning and normal operation take place, the monthly emissions shall be the sum of the commissioning emissions and the normal operation emissions.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-7-2002]

[Devices subject to this condition: D27, D31, D36, D39]

~~A99.3~~ **A99.6** The 2**.0** PPM NOX emission limit(s) shall not apply during turbine **commissioning,** startups and shutdowns.

For the purposes of this condition, a startup begins with the initiation of combustion, and concludes at the end of the 15-minute quadrant in which BACT is achieved or the startup is aborted by a trip. A startup may include one or more trips and restart attempts. A trip is an event in which the turbine experiences an automatic equipment shutdown to prevent equipment damage or as a result of equipment malfunction.

A cold startup shall be defined as a startup which occurs after the turbine has been shut down for more than 48 hours. Each cold startup, without a trip, shall not exceed 120 minutes. Each cold startup, with one or more trips, shall not exceed 150 minutes. NOx emissions for a cold startup, with or without trip(s), shall not exceed 122.8 lbs.

A non-cold startup shall be defined as a startup which occurs after the turbine has been shut down for 48 hours or less. Each non-cold startup, without a trip, shall not exceed 90 minutes. Each non-cold startup, with one or more trips, shall not exceed 120 minutes. NOx emissions for a non-cold startup, with or without trip(s), shall not exceed 51.3 lbs.

A shutdown is a controlled process of unloading the turbine/generator and opening the generator breaker. A shutdown begins 30 minutes prior to cessation of combustion and ends with cessation of combustion. Each shutdown shall not exceed 30 minutes. NOx emissions for a shutdown shall not exceed 4.5 lbs.

The turbine shall be limited to a maximum of 10 startups per month, which includes no more than 5 cold startups per month, with no more than 2 startups in any day. The turbine shall be limited to a maximum of 56 startups per year, which includes no more than 30 cold startups per year.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

[RULE 2005, ~~6-3-2011~~ **12-4-2015**]

[Devices subject to this condition: D27, D31, D36, D39]

~~A99.4~~ **A99.7** The 2**.0** PPM CO emission limit(s) shall not apply during turbine **commissioning,** startups and shutdowns.

For the purposes of this condition, a startup begins with the initiation of combustion, and concludes at the end of the 15-minute quadrant in which BACT is achieved or the startup is aborted by a trip. A startup may include one or more trips and restart attempts. A trip is an event in which the turbine experiences an automatic equipment shutdown to prevent equipment damage or as a result of equipment malfunction.

A cold startup shall be defined as a startup which occurs after the turbine has been shut down for more than 48 hours. Each cold startup, without a trip, shall not exceed 120 minutes. Each cold startup, with one or more trips, shall not exceed 150 minutes. CO emissions for a cold startup, with or without trip(s), shall not exceed 204.8 lbs.

A non-cold startup shall be defined as a startup which occurs after the turbine has been shut down for 48 hours or less. Each non-cold startup, without a trip, shall not exceed 90 minutes. Each non-cold startup, with one or more trips, shall not exceed 120 minutes. CO emissions for a non-cold startup, with or without trip(s), shall not exceed 59.9 lbs.

A shutdown is a controlled process of unloading the turbine/generator and opening the generator breaker. A shutdown begins 30 minutes prior to cessation of combustion and ends with cessation of combustion. Each shutdown shall not exceed 30 minutes. CO emissions for a shutdown shall not exceed 10.8 lbs.

The turbine shall be limited to a maximum of 10 startups per month, which includes no more than 5 cold startups per month, with no more than 2 startups in any day. The turbine shall be limited to a maximum of 56 startups per year, which includes no more than 30 cold startups per year.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; **RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition: D27, D31, D36, D39]

~~A99.5~~ **A99.8** The 2**.0** PPM VOC emission limit(s) shall not apply during turbine **commissioning,** startups and shutdowns.

For the purposes of this condition, a startup begins with the initiation of combustion, and concludes at the end of the 15-minute quadrant in which BACT is achieved or the startup is aborted by a trip. A startup may include one or more trips and restart attempts. A trip is an event in which the turbine experiences an automatic equipment shutdown to prevent equipment damage or as a result of equipment malfunction.

A cold startup shall be defined as a startup which occurs after the turbine has been shut down for more than 48 hours. Each cold startup, without a trip, shall not exceed 120 minutes. Each cold startup, with one or more trips, shall not exceed 150 minutes. VOC emissions for a cold startup, with or without trip(s), shall not exceed 1.75 lbs.

A non-cold startup shall be defined as a startup which occurs after the turbine has been shut down for 48 hours or less. Each non-cold startup, without a trip, shall not exceed 90 minutes. Each non-cold startup, with one or more trips, shall not exceed 120 minutes. VOC emissions for a non-cold startup, with or without trip(s), shall not exceed 1.55 lbs.

A shutdown is a controlled process of unloading the turbine/generator and opening the generator breaker. A shutdown begins 30 minutes prior to cessation of combustion and ends with cessation of combustion. Each shutdown shall not exceed 30 minutes. VOC emissions for a shutdown shall not exceed 0.71 lbs.

The turbine shall be limited to a maximum of 10 startups per month, which includes no more than 5 cold startups per month, with no more than 2 startups in any day. The turbine shall be limited to a maximum of 56 startups per year, which includes no more than 30 cold startups per year.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition and the records shall be made available to District personnel upon request.

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

[Devices subject to this condition: D27, D31, D36, D39]

~~A195.1~~ **A195.5** The 2**.0** PPMV NOX emission limit(s) is averaged over 1 hour at 15 percent oxygen, dry basis.

[RULE 2005, ~~6-3-2011~~ **12-4-2015**]

[Devices subject to this condition: D27, D31, D36, D39]

~~A195.2~~ **A195.6** The 2**.0** PPMV CO emission limit(s) is averaged over ~~3 hours~~ **1 hour** at 15 percent oxygen, dry basis.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002**; RULE 1703(a)(2) - PSD-BACT, 10-7-1988**]

[Devices subject to this condition: D27, D31, D36, D39]

~~A195.3~~ **A195.7** The 2**.0** PPMV VOC emission limit(s) is averaged over 1 hour at 15 percent oxygen, dry basis.

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

[Devices subject to this condition: D27, D31, D36, D39]

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: D27, D31, D36, D39]

~~C1.4~~ **C1.6** The operator shall limit the fuel usage to no more than ~~330~~ **405** MM cubic feet in any one calendar month.

For the purpose(s) of this condition, the limit shall be based on the total combined fuel usage for each turbine and associated duct burner.

The purpose(s) of this condition is to ensure **compliance with the condition ~~A63.3~~ A63.4 monthly emission limits** ~~that the total PM10 emissions shall not exceed 2,438 lbs/month per turbine.~~

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

[Devices subject to this condition: D27, D31, D36, D39]

D12.3 The operator shall install and maintain a(n) non-resettable totalizing fuel flow meter to accurately indicate the fuel usage of the turbine.

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; Rule 2005, ~~6-3-2011~~ **12-4-2015**]

[Devices subject to this condition: D27, D31, D36, D39]

***Note*: For conditions D29.2 and D29.3 below, the source test methods will be updated to current source testing requirements.**

~~D29.2~~ **D29.4** The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging Time	Test Location
PM**10** emissions	~~Approved District method~~ **EPA Method 201A/ District Method 5.1**	District-approved averaging time	Outlet of the SCR serving this equipment
VOC	~~Approved District method~~ **District method 25.3 Modified**	1 hour	Outlet of the SCR serving this equipment
SOX emissions	~~Approved District method~~	District-approved	Fuel Sample

| **AQMD Laboratory Method 307-91** | averaging time |

Source testing shall be conducted within 180 days after initial startup of the Siemens A-Plus Turbine Upgrade project, unless otherwise approved in writing by the Executive Officer. The test shall be conducted at least once every three years **thereafter**.

The test shall be conducted and the results submitted to the District within 60 days after the test date. The District shall be notified of the date and time of the test at least 10 days prior to the test.

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

The test shall be conducted 1) when the gas turbine and the duct burner are operating simultaneously at 100 percent of maximum heat input and 2) when the gas turbine is operating alone at 100 percent of maximum heat input.

The sampling time for the PM10 test(s) shall be 4 hours or longer as necessary to obtain a measureable amount of sample.

~~The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit. For natural gas fired turbines only, this shall be demonstrated by the following test method:~~

For natural gas fired turbines only, for the purpose of demonstrating compliance with VOC BACT limits as determined by SCAQMD, the operator shall use Method 25.3 modified as follows:

a) **Triplicate** ~~S~~**s**tack gas samples ~~are~~ extracted **directly** into Summa canisters, maintaining a final canister pressure between 400 – 500 mm Hg absolute**,**

b) Pressurization of **the** Summa canisters ~~is done~~ with zero gas analyzed/certified to ~~containing~~ less than 0.05 ppmv total hydrocarbons as carbon**, and**

~~c) Analysis of Summa canisters is per EPA Method TO-12 (with pre-concentration) and the temperature of the Summa canisters when extracting samples for analysis is not to be below 70 degrees F~~

~~Because the BACT level was set using data derived from various source test methods, this alternate method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results must be reported with two significant digits.~~

c) Analysis of Summa canisters per 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 modified method for VOC compliance determination does not mean that it is more accurate than 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 VOC calculated as carbon for natural gas fired turbines.

For purposes of this condition, an alternative test method may be allowed for any of the above pollutants upon concurrence by EPA, CARB, and SCAQMD.

[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 1303(b)(2)-Offset, 12-6-2002]

[Devices subject to this condition: D27, D31, D36, D39]

~~D29.3~~ **D29.5** The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant(s) to be tested	Required Test Method(s)	Averaging. Time	Test Location
NH3 emissions	District Method 207.1 ~~and 5.3 or EPA Method 17~~	1 hour	Outlet of the SCR serving this equipment

Source testing shall be conducted within 180 days after initial startup of the Siemens A-Plus Turbine Upgrade project, unless otherwise approved in writing by the Executive Officer. The test shall be conducted at least ~~once every calendar quarter for the first year and~~ annually thereafter.

The test shall be conducted and the results submitted to the District within 60 days after the test date. The District shall be notified of the date and time of the test at least 10 days prior to the test.

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

The NOx concentration, as determined by the certified CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable or not yet certified, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 2005, ~~6-2011~~ **12-4-2015]**

[Devices subject to this condition: ~~C33, C41~~ **D27, D31, D36, D39**]

Note: Pursuant to permitting practice at the time the FDOC was issued, the devices subject to the above periodic ammonia testing condition were the SCR systems (C33, C41). Pursuant to current permitting practice, the devices subject to this condition will be the four turbines (D27, D31, D36, D39).

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 will convert the actual CO concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.

The CEMS shall be installed and operated to measure CO concentration over a 15 minutes averaging time period**.**

[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 1303(B)(2)-Offset, 12-6-2002~~ **RULE 218, 5-14-1999**]

[Devices subject to this condition: D27, D31, D36, D39]

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: D27, D31, D36, D39]

E57.1 The operator shall vent this equipment to CO oxidation/SCR control system whenever the turbine is in operation.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 2005, ~~6-3-2011~~ **12-4-2015**]

[Devices subject to this condition: D27, D31, D36, D39]

E193.2 The operator shall operate and maintain this equipment according to the following requirements:

For the Siemens A-Plus Upgrade Project, total commissioning hours shall not exceed 56.25 hours of fired operation for each turbine from the date of initial turbine upgrade start-up. Of the 56.25 hours, commissioning hours without control shall not exceed 32.5 hours.

One turbine may be commissioned at a time. The commissioning for both turbines shall be completed before normal operation for either turbine may commence.

The emergency internal combustion engine for fire pump shall not be tested during the commissioning of a turbine.

The certified NOx and CO CEMS shall be fully calibrated and operational.

The operator shall vent this equipment to the CO oxidation catalyst and SCR control system whenever the turbine is in operation after commissioning is completed.

The operator shall maintain records to demonstrate compliance with this condition and shall make such records available to the Executive Officer upon request. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD. The records shall include, but not be limited to, the total number of commissioning hours, number of commissioning hours without control, and natural gas fuel usage.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, RULE 2005, 12-4-2015]

[Devices subject to this condition: D27, D31, D36, D39]

H23.2 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
NOx	40 CFR 60, SUBPART	KKKK
SO2	40 CFR 60, SUBPART	KKKK

[40 CFR 60 Subpart A, 6-3-2016; 40 CFR 60 Subpart KKKK, 7-6-2006]

[Devices subject to this condition: D27, D31, D36, D39]

H23.3 This equipment is subject to the applicable requirements of the following Rules or Regulations:

Contaminant	Rule	Rule/Subpart
NOx	40 CFR	Part 75
SO2	40 CFR	Part 75

[40 CFR 75-Acid Rain CEM, 1-18-2012]

[Devices subject to this condition: D27, D31, D36, D39]

I298.1 This equipment shall not be operated unless the facility holds 34349 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 34349 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 condition(s) stated in this permit.

[RULE 2005, ~~6-3-2011~~ **12-4-2015**]

[Devices subject to this condition: D27]

I298.2 This equipment shall not be operated unless the facility holds 6143 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 6143 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 condition(s) stated in this permit.

[RULE 2005, ~~6-3-2011~~ **12-4-2015**]

[Devices subject to this condition: D31]

I298.3 This equipment shall not be operated unless the facility holds 34349 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 34349 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 condition(s) stated in this permit.

[RULE 2005, ~~6-3-2011~~ **12-4-2015**]

[Devices subject to this condition: D36]

I298.4 This equipment shall not be operated unless the facility holds 6143 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 6143 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 condition(s) stated in this permit.

[RULE 2005, ~~6-3-2011~~ **12-4-2015**]

[Devices subject to this condition: D39]

K40.1 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District 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) under which the test was conducted.

Source test results shall also include turbine fuel flow rate 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; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 2005~~, 6-3-2011~~ **12-4-2015**]

[Devices subject to this condition: D27, D31, D36, D39]

K67.4 The operator shall keep records, in manner approved by the District, for the following parameter(s) or item(s):

Operational status of the duct burner and its fuel usage

[RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002; RULE 2005, ~~6-3-2011~~ **12-4-2015**; RULE 2012, 5-6-2005]

[Devices subject to this condition: D31, D39]

SECTION D: FACILITY DESCRIPTION AND EQUIPMENT SPECIFIC CONDITIONS

Section D will continue to show the turbines and associated equipment as issued for the Title V renewal, A/N 561415, on 11/3/15.

Applications have not been submitted for the CO/SCR catalyst systems, fire pump, and exempt cooling tower. Bicent's Petition to Amend the Final Decision for the Malburg Generating Station (MGS) (01-AFC-25C)("Petition") submitted to the CEC for the turbine upgrade, however, proposes changes to CEC's Conditions of Certification related to the CO/SCR catalysts, fire pump, and exempt cooling tower. Therefore, the CO/SCR catalyst systems, fire pump, and cooling tower are included in this evaluation as necessary to address the applicant's proposed changes to the CEC conditions. The CO/SCR catalyst systems and fire pump are shown below.

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 3: ELECTRIC GENERATION, GAS TURBINE (MGS POWER ISLAND NO. 1)					
GAS TURBINE, NO. 1 A/N: 517249	D27	C32 C33	NOx: MAJOR SOURCE**		
BURNER, DUCT A/N: 517249	D31	C32 C33	NOX: MAJOR SOURCE**		
CO OXIDATION CATALYST, NO. 1, EMERACHEM, METAL MONOLITH, SERVING TURBINE NO. 1, VOLUME 63 CU. FT. A/N: 482570	C32	D27 D31			
SELECTIVE CATALYTIC REDUCTION, NO. 1, SERVING TURBINE NO. 1, 537.1 CU FT.; WIDTH: 10 FT 11 IN; HEIGHT: 47 FT 7 IN; LENGTH: 3 FT 6 IN WITH A/N: 482570 AMMONIA INJECTION	C33 (B34)	D27 D31		NH3: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.4, D12.4, D12.5, D12.6, ~~D29.3~~, E179.4, E179.5
STACK, NO. 1 A/N: 517249	D35				

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
System 4: ELECTRIC GENERATION, GAS TURBINE (MGS POWER ISLAND No. 2)					
GAS TURBINE, NO. 2 A/N: 517250	D36	C40 C41	NOX: MAJOR SOURCE**		
BURNER, DUCT BURNER A/N: 517250	D39	C40 C41	NOX: MAJOR SOURCE**		
CO OXIDATION CATALYST, NO. 2, EMERACHEM, METAL MONOLITH, SERVING TURBINE NO. 2, VOLUME 63 CU. FT. A/N: 482571	C40	D36 D39			
SELECTIVE CATALYTIC REDUCTION, NO. 2, SERVING TURBINE NO. 2, 537.1 CU FT.; WIDTH: 10 FT 11 IN; HEIGHT: 47 FT 7 IN; LENGTH: 3 FT 6 IN WITH A/N: 482571 AMMONIA INJECTION	C41	D36 D39		NH3: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	A195.4, D12.4, D12.5, D12.6, ~~D29.3~~, E179.4, E179.5
STACK, NO. 2 A/N: 517250	D43				
System 5: FIRE WATER PUMP DRIVER					
INTERNAL COMBUSTION ENGINE, EMERGENCY FIRE, DIESEL FUEL, DEUTZ, MODEL BF6M2012, WITH AFTERCOOLER, TURBOCHARGER, 173 BHP A/N: 482576	D48		NOX: PROCESS UNIT**	CO: 0.4 GRAM/BHP-HR DIESEL (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(A)(1)-BACT, 12-6-2002]; NOX: 3.9 GRAM/BHP-HR DIESEL (4) [RULE 2005,6-3-2011]; NOX: 469 LBS/1000 GAL DIESEL (1) [RULE 2012, 5-6-2005]; NOX: 469 LBS/1000 GAL DIESEL (1) [RULE 2012, 5-6-2005]; PM10: 0.09 GRAM/BHP-HR DIESEL (4) [RULE 1303(A)(1)-BACT, 5-10-1996; RULE	B61.2, C1.5, D12.2, E193.1, I298.5, K48.1, K67.2

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
				1303(a)(1)-BACT, 12-6-2002]; VOC: 0.1 GRAM/BHP-HR DIESEL (4) [RULE 1303(A)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]	

(1) Denotes RECLAIM emission factor (2) Denotes RECLAIM emission rate
(3) Denotes RECLAIM concentration limit (4) Denotes BACT emissions limit
(5)(5A)(5B) Denotes command & control emission limit (6) Denotes air toxic control rule limit
(7) Denotes NSR applicability limit (8)(8A)(8B) Denotes 40 CFR limit (e.g. NSPS, NESHAPS, etc.)
(9) See App B for Emission Limits (10) See Section J for NESHAP/MACT requirements

** Refer to Section F and G of this permit to determine the monitoring, recordkeeping and reporting requirements for this device.

SELECTIVE CATALYTIC REDUCTION/CO CATALYST SYSTEMS

Note: *Bicent's Petition proposes changes to CEC's Conditions of Certification AQ-12, AQ-19, AQ-20, and AQ-21 to conform to SCAQMD conditions C157.1, D12.4, D12.5, and D12.6, respectively. The SCAQMD had updated these four conditions for the Title V renewal facility permit, issued 11/3/15. These conditions are shown below for reference only.*

A195.4 The 5 PPMV NH3 emission limit(s) is averaged over 1 hour at 15 percent oxygen, dry basis. The operator shall calculate and continuously record the ammonia slip concentration using the following formula.

NH3 (ppmv) = [a – b*c/1000000)] * (1000000 * d/b), where:

a = ammonia injection rate (lbs/hr)/17 (lbs/lb-mole)
b = dry exhaust gas flow rate (lbs/hr)/29 (lbs/lb-mole)
c = change in measured NOx concentration across SCR (ppmv, dry basis)
d = correction derived by comparing the measured and calculated NH3 slip concentration during annual compliance testing

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent and calibrated at least once every 12 months.

The calculated NH3 value may not be used for compliance determination without corroborative data using an approved reference method for determination of ammonia.

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

[Devices subject to this condition: C33, C41]

D12.4 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia (NH3).

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The operator shall maintain the ammonia injection rate between 5 lb/hr and 175 lb/hr.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 2005, 6-3-2011]

[Devices subject to this condition: C33, C41]

D12.5 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature of the exhaust at the inlet of the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The exhaust temperature at the inlet of the SCR/CO catalyst shall be maintained between 350 deg F and 750 deg F, except during startups and shutdowns.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 2005, 6-3-2011]

[Devices subject to this condition: C33, C41]

D12.6 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.

The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.

The pressure drop across the catalyst shall be between 0.15 and 2.0 inches water column.

[RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002; RULE 2005, 6-3-2011]

[Devices subject to this condition: C33, C41]

INTERNAL COMBUSTION ENGINE

Note: *This evaluation references condition C1.5 only.*

C1.5 The operator shall limit the operating time to no more than 200 hour(s) in any one year.

Operations for maintenance and testing as defined in Rule 1470 shall not exceed 50 hours in any one calendar year. The total annual operating time includes all operations including maintenance and testing.

[RULE 1110.2, 2-1-2008; RULE 1110.2, 9-7-2012; RULE 1304(a)-Modeling and Offset Exemption, 6-14-1996; RULE 1470, 5-4-2012; RULE 2012, 5-6-2005]

[Devices subject to this condition: D44]

BACKGROUND

Malburg Generating Station, LLC, is a subsidiary of Bicent (California) Malburg, LLC ("Bicent") (ID 155474). The Malburg Generating Station ("MGS") generates electric power for sale to the City of Vernon. The MGS is Title V and RECLAIM, with the Title V term running from 11/3/15 to 11/2/20.

The MGS had been constructed by the Vernon City, Light & Power Dept. (renamed to City of Vernon, Vernon Gas & Electric, then to the current Vernon Public Utilities) (ID 14502) to augment its original power plant. The Permits to Construct for the original project were issued on 5/27/03, and the Permits to Operate on 1/31/08. The City began construction in 2003, with commercial operations beginning in 2005. The transfer of operator from the City of Vernon to Bicent occurred in April 2008. The change of operator permits were issued on 3/18/09.

The MGS consists of (1) two identical Alstom GTX100 combined cycle, natural gas fueled combustion turbines (D27, D36) with duct burners (D31, D39), each turbine with a generator rated at 44.2 MW gross each, heat recovery steam generator, and a common steam turbine generator; (2) two CO oxidation catalyst (C32, C40) and selective catalytic reduction (SCRs) (C33, C41); (3) 8800 gallon 19% aqueous ammonia tank (D44); (4) oil water separator (D45); and (5) 173 bhp diesel emergency internal combustion engine for a fire pump (D48). The cooling tower is exempt from permitting. (The Vernon Public Utilities (ID 14502) continues to operate its original power plant, located adjacent to the MGS, consisting of two peaking turbines and six emergency internal combustion engines.)

California Energy Commission

The California Energy Commission (CEC) is the lead agency for licensing thermal power plants 50 megawatts and larger under the California Environmental Quality Act (CEQA) and has a certified

regulatory program under CEQA. Under its certified program, the CEC is exempt from having to prepare an environmental impact report. The CEC certified the License for the MGS on 5/23/03. The MGS began commercial operations in October of 2005.

On 11/21/17, Bicent filed the *Petition to Amend the Final Decision for the Malburg Generating Station* (01-AFC-25C) ("Petition") with the CEC to amend the existing MGS Final Decision. The Petition requested approval for the installation of the Siemens SGT-800 A-Plus Turbine Upgrade package ("A+ Turbine Upgrade") on the two turbines to increase power output, as well as requested revisions to existing Conditions of Certification.

On 2/4/19, Bicent filed the *Petition to Amend for Site Delineation* to further amend the CEC Decision for the MGS. On April 10, 2008, Bicent acquired the MGS from the City of Vernon and filed a petition for change of ownership, which was approved by the CEC in May 2008. This CEC approval of the transfer of ownership did not include any specific delineation of the site boundary. Furthermore, it did not distinguish the facilities to remain in control by the City of Vernon and those to be transferred to Bicent. The Petition requested modification of the site boundary to reflect that Bicent does not control certain portions within the current site boundary and ancillary facilities, which are still owned and operated by the City of Vernon. These areas include the natural gas pipeline, the landscaping area outside the boundary of the MGS, and Station A, a designated historical resource. Based on the proposed site delineation, the Petition also requested deletion of Conditions of Certification HAZ-6, HAZ-7, VIS-2, VIS-3, and CUL-8. (HAZ refers to hazardous materials conditions of certification, CUL refers to cultural resources conditions, and VIS refers to visual resources conditions).

SCAQMD Applications Submitted

On 11/14/17, Bicent submitted A/N 598922 and A/N 598923 ("Application") to modify Alstom GTX100 Turbines No. 1 (A/N 517249) and No. 2 (A/N 517250), respectively, by installing an A+ Turbine Upgrade package on each turbine. A/N 598925 was submitted as the associated RECLAIM/Title V revision application.

The Application also proposed emissions-related changes and provided air dispersion modeling and health risk assessment for the facility, including the fire pump and the cooling tower. The environmental consultant is Greg Darvin, Atmospheric Dynamics.

The application nos. and fees are summarized below. The fees are from Rule 301—Permitting and Associated Fees, amended on 7/1/17.

- The two turbines are identical. Rule 301(c)(1)(F) states: "When applications are submitted in accordance with the provisions of subparagraphs (c)(1)(A), (c)(1)(D), (c)(1)(E), (c)(1)(I), paragraphs (c)(3) or (c)(4) concurrently for identical equipment …, full fees for the first application, and fifty percent (50%) of the applicable processing fee for each additional application shall be assessed."

- The facility requested expedited permit processing. Rule 301(v)(1) states: "Fees for requested expedited processing of permit applications will be an additional fee of fifty percent (50%) of the applicable base permit processing fee (after taking any discounts for identical equipment but not the higher fee for operating without a permit) by equipment schedule."

Rule 301, *Table IB - Permit Fee Rates For Basic Equipment* provide that a "Gas Turbine, <= 50 MW, other fuel" is a Schedule D. Past practice has been to base fees on the nominal rating of a turbine, which is the gross MW rating at Independent System Operator (ISO) standard conditions (59 ºF, 1 atm, 60% relative humidity). These conditions correspond to Scenario S14 (100% load, 59 ºF ambient, no duct burner). The turbine upgrade will increase the nominal rating for each turbine from 42.951 MW-gross (from Appendix B-5 of Application for P/C, A/N 394164) to 47.154 MW-gross based on Siemens Table 1. (See **TURBINE EQUIPMENT DESCRIPTION UPDATES ON FACILITY PERMIT** below for discussion on Siemens Table 1.)

- As the turbine rating remains <= 50 MW, the schedule remains Schedule D.

Table 1 - Applications for Permits to Construct Submitted to SCAQMD

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees
598922	11/14/17	2/14/18	Turbine No. 1, Combined-Cycle	$6148.34 (Schedule D) * 1.5 (XPP) = $9222.51
598923	11/14/17	2/14/18	Turbine No. 2, Combined-Cycle (identical)	[$6148.34 x 0.5 (identical)] * [1.5 (XPP)] = $4611.26
598925	11/14/17	2/14/18	RECLAIM/ Title V Permit Revision	$2247.02
			Total Fees	$16,080.79

Note: *A/N 598922 is the master file.*

Additional Information Letters

The applications were deemed complete on 2/14/18 to meet internal application acceptance requirements. On 5/1/18, SCAQMD issued an additional information letter (SCAQMD AI Letter, 5/1/18). On 5/17/18, Bicent provided a response letter with attachments (Bicent Response Letter, 5/17/18). On 9/26/18, the SCAQMD issued a second additional information letter (SCAQMD AI Letter, 9/26/18). On 10/20/18, Bicent provided a response letter with attachments (Bicent Response Letter, 10/20/18). On 1/9/19, the SCAQMD issued a third additional information e-mail (SCAQMD AI E-mail, 1/9/19). On 1/23/19, Bicent provided a response letter (Bicent Response Letter, 1/23/19).

PERMITTING HISTORY

The permitting history for the two turbines, two SCR/Oxidation Catalyst Systems and Fire Pump is provided below as reference for this evaluation and future evaluations. In addition, the permitting history provides background for the revisions proposed in the Application and in the Petition, which will be summarized in the section immediately following the permitting history.

Vernon City, Light & Power Dept. (ID 14502)

- **Turbines No. 1 and 2 (D27, D36) & Duct Burners No. 1 and 2 (D31, D39)**

  1. A/N 394164 & 394165

  Initial applications for P/Cs for Turbines No. 1 & 2, submitted 12/7/01. Final Determination of Compliance ("FDOC"), dated 12/12/02 and issued 12/13/02. P/Cs issued 5/27/03.

  *****On-Base Image Retrieval System***

  A/N 394164 is the master file for the Malburg Generating Station project. Under "*ENG--Application Folder,*" there is one volume containing miscellaneous documents (749 pages).

  Under "*ENG--Accessions,*" there are 20 volumes, chronologically dated from 2000 – 2005. These materials include the original and supplemental application packages prepared by Parsons.

  2. A/N 443084 & 443085

  Change of condition applications for Turbines No. 1 & 2, submitted 4/22/05, to revise the CO emission factors for the commissioning period and the interim period prior to CO CEMS certification, as well as to revise the initial source testing condition to clarify that the duct burner is not required to be in operation at 50% and 75% turbine loads for NOx, CO, VOC, and ammonia tests. Revised P/Cs issued on 7/26/05. P/Os issued 1/31/08.

  3. A/N 486719 & 486721

  Administrative revision applications for Turbines No. 1 & 2, submitted 8/21/08, to revise the turbine and duct burner heat input rates from a low heating value to a high heating value basis. P/O issued 9/19/08.

- **CO Oxidation Catalyst/SCR Systems No. 1 and 2 (C32/C33, C40/C41)**
  - **A/N 394166 & 394167**

    Initial applications for P/Cs for CO Oxidation/SCR Systems No. 1 & 2, submitted 12/7/01. P/Cs issued 5/27/03. P/Os issued 1/31/08.

- **Fire Pump, Emergency Internal Combustion Engine (D48)**

  1. A/N 403104

  Application for P/C for Caterpillar fire pump (D46), rated at 266 bhp, submitted 6/21/02. Final Determination of Compliance ("FDOC"), dated 12/12/02 and issued 12/13/02. P/C

issued 5/27/03. Application cancelled 4/15/05, as Deutz fire pump, A/N 438859, will be installed instead.

2. A/N 438859

Initial application for P/C for Deutz fire pump (D48), rated at 173 bhp, submitted 1/14/05. P/C issued 6/14/05, and P/O issued 1/31/08.

Note: The SCAQMD did not require modeling for this emergency internal combustion engine, because emergency engines are exempt from modeling requirements pursuant to Rule 1304 (a) and Rule 2005(k)(5). The CEC required facility-wide PM_{10} modeling and imposed Condition of Certification AQ-C8 which prohibited fire pump testing on the same day as either turbine has been start up or shut down. As discussed below, the Petition proposes to change AQ-C8 to prohibit testing in the same hour as a startup or shutdown event and provides air quality modeling to support the change.

Bicent (California) Malburg LLC (ID 155474)

- **Turbines No. 1 and 2 (D27, D36) & Duct Burners No. 1 and 2 (D31, D39)**

1. A/N 482563 & 482568

Applications for change of operator for Turbines No. 1 and 2, submitted on 5/15/08. P/Os issued 3/18/09.

2. A/N 517429 & 517250

Permit condition change applications for Turbines No. 1 & 2, submitted 12/16/10, to revise condition nos. A99.3 and A99.4 (then limiting the number of startups and shutdowns to one per day) to allow a maximum of two startups and two shutdowns per day during a period not to exceed five days per year (within a 30 day window of time) during which required annual maintenance is conducted.

Conditions A99.3 and A99.4 were drafted in 2002 and did not include restrictions imposed on startups and shutdowns found in more recent permits. The conditions were as follows:

A99.3 The 2 PPM NOX emission limit(s) shall not apply during turbine startups and shutdowns. The startups shall not exceed 2 hours per startup and the number of startup shall not exceed one per day. Shutdowns shall not exceed 30 minutes per shutdown and the number of shutdown shall not exceed one per day. Written records of startups and shutdowns shall be kept and made available to AQMD.

A99.4 The 2 PPM CO emission limit(s) shall not apply during turbine startups and shutdowns. The startups shall not exceed 2 hours per startup and the number of startup shall not exceed one per day. Shutdowns shall not exceed 30 minutes per shutdown and the number of shutdown shall not exceed one per day. Written records of startups and shutdowns shall be kept and made available to AQMD.

Bicent had been required to seek a variance from conditions nos. A99.3 and A99.4 in 2009 (Case No. 5727-1) and in 2010 (Case No. 5727-3) to accommodate startups and testing during the annual maintenance period for its two turbines. During the last variance hearing in 2010, the Hearing Board directed Bicent to seek a permit revision to accommodate more than one startup and shutdown per day during this startup/testing period in lieu of seeking a variance, because annual maintenance activities are not "beyond the reasonable control" of Bicent since they are planned and known to be necessary in advance of the variance period. The applications were submitted by a law firm as a follow-up to the variance hearing in 2010.

The changes to conditions A99.3 and A99.4, addition of condition A99.5, and changes to conditions I298.1 and I298.2 are discussed below because they are relevant to the evaluation of the turbine upgrade project.

A. Conditions A99.3 (NOx) and A99.4 (CO)

In addition to revising the conditions to change the one startup/shutdown per day requirement as proposed by the applicant, the SCAQMD updated the conditions to reflect then current permit conditions regarding startups and shutdowns. These conditions indicated that the BACT levels for NOx and CO, respectively, shall not apply during startups and shutdowns. Subsequent to the issuance of the initial permits for this facility, in lieu of requiring steady state BACT at all times, EPA accepted an alternative BACT which limits and minimizes emissions during periods when steady state BACT is not achievable, such as during startups and shutdowns. Consequently, these conditions were updated to include the alternative BACT requirements. (See below for the discussion on the addition of analogous new condition A99.5 for VOC.)

The startup limits were revised to update/add the: (1) number of cold starts per month and year; (2) number of non-cold starts per month and year; (3) number of starts per day; (4) duration of cold starts and non-cold start; and (5) NOx, CO, and VOC emissions per cold start and non-cold start. The shutdown limits were revised to update/add the: (1) duration of shutdown; and (2) NOx, CO, and VOC emissions per shutdown.

Note: Bicent did not provided modeling for the startup and shutdown parameters that had changed since the FDOC. As discussed below, the Application for the turbine upgrade project provides facility-wide air quality modeling which incorporates the updates to conditions A99.3 and A99.4.

The updates and additions to conditions A99.3 and A99.4 are discussed below.

- Definitions of Cold Start, Non-Cold Start, Shutdown, and Trip

  Although the definitions of cold startup, non-cold startup, and shutdown were not included in conditions A99.3 and A99.4, the FDOC defined cold start to occur after

more than 72 hours of shutdown, warm start to occur between 8 and 72 hours inclusive of shutdown, and hot start to occur within 8 hours of shutdown.

When informed that the definitions of cold startup, non-cold startup, and shutdown would be added to conditions A99.3 and A99.4, the facility requested that the cutoff for cold start be decreased from 72 hours to 48 hours because the equipment had been observed to be just as cold after 48 hours shutdown as after 72 hours.

Further, the facility provided input for the definition of "startup," "trip," "cold startup," "non-cold startup," and "shutdown," which were added to conditions A99.3 and A99.4.

- Number of Cold Startups Increases, Monthly and Annual
  - Monthly Cold Startups

    Although the number of cold startups per month were not included in conditions A99.3 and A99.4, the FDOC assumed one cold startup, 4 warm startups (includes warm and hot starts), and 5 shutdowns for the maximum emissions month, pursuant to the standard procedure for calculating the monthly maximum emissions for continuously operating equipment. Cold start was defined to occur after more than 72 hours of shutdown, warm start to occur between 8 and 72 hours inclusive of shutdown, and hot start to occur within 8 hours of shutdown.

    Bicent proposed that conditions A99.3 and A99.4 be revised from allowing one startup/shutdown per day to allowing a maximum of two startups and two shutdowns per day during a period not to exceed five days per year (within a 30 day window of time) during which required annual maintenance is conducted. For NSR, this translates to five cold starts, 5 non-cold starts (new terminology for warm and hot startups), and 10 shutdowns for the maximum emissions month.

    For A/N 517429 & 517250, the SCAQMD revised conditions A99.3 and A99.4 to remove the one startup and one shutdown per day limit. The conditions added that the turbine shall be limited to a maximum of 10 startups per month, which included no more than 5 cold startups per month, with no more than 2 startups in any day. This was to be for any month, not a single month in which maintenance takes place, because NSR is based on the maximum emissions month.

  - Annual Cold Startups

    Although the number of cold startups per month were not included in conditions A99.3 and A99.4, the FDOC was based on the applicant's request for a maximum of 56 total startups, 4 cold and 52 warm. This was the basis for the number of NOx RTCs required by condition nos. I298.1 and I298.2.

When informed that annual limits would be added to conditions A99.3 and A99.4, Bicent requested a maximum of 56 total startups, with a maximum of 30 cold starts. The facility had been permitted as a base load power plant, which provided a continuous supply of electrical power throughout the year, with few startups and shutdowns. However, at any time in the future, the plant could be used more as a peaker plant, which provides electrical power only when there is a high demand, with more frequent startups and shutdowns. Therefore, it was imperative that they maintain startup flexibility to keep plant operations viable.

For A/N 517429 & 517250, the SCAQMD revised conditions A99.3 and A99.4 to add that the turbine shall be limited to a maximum of 56 startups per year, which includes no more than 30 cold startups per year.

- NOx & CO Emissions Increases for Cold Startups

  Although the NOx and CO emissions per cold startup were not included in conditions A99.3 and A99.4, the FDOC was based on 15.75 lb/cold start NOx and 24.5 lb/cold start CO provided by the turbine manufacturer. The maximum hourly emissions were 13.1 lb/hr NOx and 24.3 lb/hr CO for each turbine.

  Upon reviewing the applications for A/N 517429 & 517250, the SCAQMD discovered that the emissions per cold start and the maximum hourly emissions for NOx and CO had substantially increased. The increases were approved by the CEC in 2008 for a Petition filed by the City of Vernon, but applications had not been submitted to the SCAQMD. P. 4 of the application cover letter, dated 12/13/10, stated: "Fourth, pursuant to Bicent's California Energy Commission license, each turbine is subject to NOx limits of 55 lbs/hr, 230 lbs/day and 53,044 lbs/year and CO limits of 140 lbs/hr, 245 lbs/day and 37,768 lbs/yr." When the SCAQMD requested a copy of the relevant CEC documents, the applicant provided a copy of the "Staff Analysis of Proposed Modifications of Conditions Relating to Startup Emission Limits for Combustion Turbines," dated 3/26/08, which was prepared by Joseph M. Loyer and which included a CEC cover letter, dated 3/27/08, from Steve Munro, Compliance Project Manager. The above emissions limits were listed on pg. 6 of the staff analysis, which was prepared in response to a petition filed by the City of Vernon on 12/19/07 to increase cold startup emissions limits for NOx and CO based on previous exceedances. CEC Order No. 08-813-4, dated 8/13/08, approved the Petition to Modify Condition AQ-C10 Regarding Air Emission Limits Related to Cold Startups, with the proposed emission limits, as modified by staff. AQ-C10 sets forth hourly, daily, and annual emissions limits. The Order stated: "The modifications were approved by the South Coast Air Quality Management District. No District permit changes are necessary."

Although the CEC was correct that no District permit condition changes were necessary, permit applications should have been submitted to the SCAQMD. Consequently, the District had not previously evaluated the emissions limit increases approved by the CEC. Therefore, these increases were evaluated with the other changes to conditions A99.3 and A99.4.

The revised hourly, daily, and annual emissions limits in CEC Condition AQ-C10, approved by CEC Order No. 08-813-4, are not relevant to the SCAQMD's emissions calculations for 30-day averages. The changes to the maximum hourly emissions and lbs/cold start for NOx and CO, however, are relevant to the SCAQMD's air quality modeling and emissions calculations for 30-day averages. These changes are summarized in the table below.

Table 2--Cold Startup Emissions Increases
(A/N 517429 & 517250-Startup & Shutdown Revisions)

Pollutants	Maximum Hourly Emissions		Lbs/Cold Start	
	Pre-Condition Change (FDOC)	**Post-Condition Change: CEC Order [1]**	**Pre-Condition Change (FDOC)**	**Post-Condition Change: CEC Staff Analysis [2]**
NOx	26.2 lb/hr for two turbines [Per FDOC, 13.1 lb/hr for one turbine]	55 lb/hr for two turbines [equal to 27.5 lb/hr for one turbine]	15.75 lb/event per FDOC (15.25 lb/event per CEC Staff Analysis)	122.8 lb/event
CO	48.6 lb/hr for two turbines [Per FDOC, 24.3 lb/hr for one turbine]	140 lb/hr for two turbines [equal to 70 lb/hr for one turbine]	24.5 lb/event	204.8 lb/event

[1] CEC Order No. 08-813-4, p. 3.
[2] CEC Staff Analysis, p. 2.

The SCAQMD informed the facility that the NOx and CO emission limits for a cold start, as established by CEC Order No. 08-813-4 in 2008 for the City of Vernon, would be added to conditions A99.3 and A99.4. The facility provided confirmation that the turbines have continued to meet the aforementioned limits.

For A/N 517429 & 517250, the SCAQMD revised condition A99.3 to add a limit of 122.8 lb/cold start NOx, and condition A99.4 to add a limit of 204.8 lb/cold start CO. As discussed below for the regulatory analysis of *Rule 1303(b)(1)—Modeling (CO, PM_{10} & SOx)and Rule 2005(c)(1)(B)—Modeling (RECLAIM NOx)*, Bicent did not provide a modeling analysis for the increases in NOx and CO emissions.

- NOx & CO Emission Increases for Non-Cold Startups

  Although the NOx and CO emissions per non-cold startup were not included in conditions A99.3 and A99.4, the FDOC was based 13.43 lb/warm start NOx and 9.95 lb/warm start CO. The warm start limits were applicable to warm and hot starts.

  The SCAQMD informed the facility that NOx and CO emission limits for a non-cold start (new terminology encompassing both warm and hot starts) would be added to conditions A99.3 and A99.4. The facility was requested to provide updated non-cold start emissions based on actual CEMS data for one year, which would be comprised of 56 starts as the FDOC was based on an annual limit of 56 starts.

  The facility responded that there had been a total of 75 starts for each combustion turbine for the last five years, and only 34 of them have been warm starts. Further, CEMS minute data is maintained for one year and then that data is overwritten due to electronic storage constraints and only 15-minute and hourly data are retained. Since a "startup event" had never been configured into the DAHS, they can only extrapolate emissions using minute CEMS data for the past 12 months. The maximum emissions provided for a non-cold start were initially based on 120 minutes but were revised to be based on 90 minutes after being informed that the FDOC was based on 120 minutes for a cold start and 90 minutes for a warm start. The facility confirmed that non-cold starts take less than 90 minutes, except in the case of a trip occurring. (See below for the definition of "trip" and the effect of a trip on the duration of a cold start and on a non-cold start.)

  The new limits for non-cold starts were proposed by the facility based on actual CEMS data (90 minutes duration) and a 15% margin of safety, as follows:

Table 3 - Non-Cold Startup Emissions Increases
(A/N 517429 & 517250-Startup & Shutdown Revisions)

Pollutants	Lbs/Non-Cold Start	
	Pre-Condition Change (FDOC)	Post-Condition Change: CEMS Data
NOx	13.43 lb/event	44.6 lb/event[1] x 1.15 = 51.3
CO	9.95 lb/event	52.1 lb/event[2] x 1.15 = 59.9

[1] Turbine No. 1 on 7/4/12.
[2] Turbine No. 2 on 2/26/12.

For A/N 517429 & 517250, the SCAQMD revised condition A99.3 to add a limit of 51.3 lb/non-cold start NOx, and condition A99.4 to add a limit of 59.9 lb/non-cold start CO.

- NOx & CO Emissions Changes for Shutdowns

  Although the NOx and CO emissions per shutdown were not included in conditions A99.3 and A99.4, the FDOC was based on 5.51 lb/shutdown NOx and 4.75 lb/shutdown CO.

  The SCAQMD informed the facility that NOx and CO emission limits for a shutdown would be added to conditions A99.3 and A99.4. The facility was requested to provide updated shutdown emissions based on actual CEMS data for one year.

  The facility responded by providing CEMS minute data for shutdowns for one year. The new limits are proposed by the facility based on actual CEMS data (30 minutes duration) and a 15% margin of safety, as follows:

Table 4 - Shutdown Emissions
(A/N 517429 & 517250-Startup & Shutdown Revisions)

Pollutants	Lbs/Shutdown	
	Pre-Condition Change (FDOC)	**Post-Condition Change: CEMS Data**
NOx	5.51 lb/event	3.95 lb/event[1] x 1.15 = 4.5
CO	4.75 lb/event	9.40 lb/event[2] x 1.15 = 10.8

[1] Turbine No. 2 on 3/3/12.
[2] Turbine No. 1 on 3/3/12.

  For A/N 517429 & 517250, the SCAQMD revised condition A99.3 to add a limit of 4.5 lb/shutdown NOx, and condition A99.4 to add a limit of 10.8 lb/shutdown CO.

- Duration of Cold Starts, Non-Cold Starts, and Shutdowns

  Conditions A99.3 and A99.4 limited startups to 2 hours and shutdowns to 30 minutes. The conditions did not distinguish between cold and non-cold starts, but the FDOC based a cold start on 2 hours, a warm start on 1.5 hours, and a shutdown on 0.5 hours.

  When informed that cold start duration and shutdown duration limits would be updated, and non-cold start duration limit would be added to conditions A99.3 and A99.4, the facility requested a 120 minutes for a cold start, and 150 minutes if one or more trips occur during the cold start. Further, the facility requested 90 minutes for a non-cold start, and 120 minutes if one or more trips occur during the non-cold start. The emissions limits for NOx and CO for cold and non-cold starts discussed above would be applicable with or without one or more trips. The shutdown duration would remain 30 minutes.

  For A/N 517429 & 517250, the SCAQMD revised conditions A99.3 and A99.4 to reflect the durations of cold starts, non-cold starts, and shutdowns requested by the facility to ensure that BACT levels are reached expeditiously.

B. Condition A99.5 Added for VOC
For A/N 517429 & 517250, the SCAQMD added condition A99.5 to specify that the 2 ppm VOC emission limit shall not apply during turbine startups and shutdowns. The new condition mirrored conditions A99.3 and A99.4, and included limits of 1.75 lbs/cold start, 1.55 lbs/non-cold start, and 0.71 lbs/shutdown based on the FDOC.

C. Conditions I298.1 and I298.2
At that time, condition I298.1 set forth the RTCs required for Turbine No. 1 and Duct Burner No. 1, and condition I298.2 set forth the RTCs required for Turbine No. 2 and Duct Burner No. 2. Conditions I298.1 and I298.2 were revised to increase the RTC holding requirement from 35263 to 40492 pounds per compliance year to reflect the revised cold start, non-cold start, and shutdown emissions limits, as well as the revised number of cold starts, non-cold starts, and shutdowns allowed per year.

3. A/N 561415—First Title V Renewal
First Title V renewal application, submitted 3/14/14, to replace the initial Title V facility permit, A/N 555011, issued to Bicent on 9/9/09 and expiring on 9/8/14. Title V renewal permit term runs from 11/3/15 to 11/2/20.

- **CO Oxidation Catalyst/SCR Systems No. 1 and 2 (C32/C33, C40/C41)**

1. A/N 482570 & 482571
Applications for change of operator for CO Oxidation/SCR Systems No. 1 & 2, submitted on 5/15/08. P/Os issued 3/18/09.

2. A/N 561415—First Title V Renewal
First Title V renewal application, submitted 3/14/14. Title V renewal permit term runs from 11/3/15 to 11/2/20.

Note:
The SCAQMD made the following revisions to conditions A195.4, D12.4, D12.5, and D12.6 for the SCR as part of the Title V renewal evaluation. As discussed below, the Petition proposes to add the SCAQMD updates to the corresponding conditions of certification in the License.

- Condition A195.4
As Bicent indicated that the equation was not accurately predicting the ammonia slip because of a misplaced parenthesis, the placement of the parenthesis was corrected and variable "d" was added to the equation. (d = correction derived by comparing the measured and calculated NH3 slip concentration during annual compliance testing.)

- Conditions D12.4, D12.5, D12.6
  As Best Available Control Technology requires the inclusion of operational requirements, operating ranges were added for injected ammonia flow rate (condition D12.4), temperature of exhaust to SCR (condition D12.5), and pressure drop across the SCR (condition D12.6).

- **Fire Pump, Emergency Internal Combustion Engine (D48)**

1. A/N 482576

Application for change of operator for Deutz fire pump, submitted on 5/15/08. P/O issued 3/18/09.

2. A/N 561415

First Title V renewal application, submitted 3/14/14. Title V renewal permit term runs from 11/3/15 to 11/2/20.

- Added condition E193.1 to implement the requirements of 40 CFR 63 Subpart ZZZZ--NESHAPS for Stationary Reciprocating Internal Combustion Engines.

PROPOSED REVISIONS IN THE APPLICATION AND IN THE PETITION FOR TURBINE UPGRADE

- **Application Nos. 598922, 598923, 598925 submitted to SCAQMD on 11/14/17**

The Application provides the following statements of project objectives and proposed revisions.

- The Application cover letter dated November 13, 2017 states: "Based on the Upgrade Package evaluation and data provided by Siemens, there will be the potential for an increase in the short-term (hourly) emissions of oxides of nitrogen (NOx), carbon monoxide (CO), volatile organic compounds (VOCs) and sulfur dioxide (SO2), primarily related to a small increase in the fuel use and firing temperatures. But based on the Siemens turbine performance data, there will be a slight decrease in the potential to emit of particulate Matter (PM10/PM2.5). However, with the proposed turbine upgrade, MGS will not seek to modify the existing monthly emission limits for any of the criteria pollutants, with the exception of annual NOx and will retain the existing permitted monthly limits for all applicable criteria pollutants with an adequate margin of safety."

- Pp. 1-20 to 1-21 of the Application states: "Based on the data summarized in the tables below and in Attachment 3, the small increase in hourly emissions from the proposed project will safely comply with the existing monthly permit limits CO, VOC's, PM10/2.5 and SOx."

- P. 1-26 of the Application states: "As summarized in Table 12, for the monthly emissions of CO, VOC's, SOx and PM10/2.5, the applicant is not proposing any changes to existing

condition A63.3 with the exception of … the revision of the monthly fuel limit to reflect the increased fuel requirements for the turbine upgrade."

The Application specifically requested the following revisions.

1. P. 1-1: Modify Turbines No. 1 and 2 by installing the Siemens A+ turbine upgrade package to increase generation capacity and combustion turbine efficiency.

2. P. 1-26: Maintain condition A63.3 limits, but revise the condition A63.3 emission factors for VOC, SOx, and PM_{10}.

3. P. 1-20: Revise I298.1, I298.2, I298.3, and I298.4 to reflect the increase in the annual emissions for NOx because based on the data provided by Siemens, emissions of criteria pollutants, with the exception of PM10/2.5, are expected to slightly increase on an hourly basis.

The Application provided emissions calculations based on the following requested revisions, which are inconsistent with the statements of project objectives and proposed revisions set forth above. Bicent Response Letters, 5/17/18 and 10/20/18, provided confirmation that Bicent is indeed requesting the following revisions.

4. Reduce the PM_{10} emission rate from 3.89 lb/hr to 2.407 lb/hr (Case/Scenario S13).

   Note: As discussed below, the SCAQMD agreed to reduce the PM_{10} emission rate to 3.386 lb/hr based on information provided by Montrose Air Quality Services and Siemens Energy.

5. Increase the condition monthly fuel limit from 330 mmcf/month to 405.24 mmcf/month per turbine.

6. Increase the operating hours per month per turbine from 645.8 hr/month (330 ft^3/month x hr/0.511 mmscf) to 720 hr/month.

7. Increase the existing SOx limit in condition A63.3 from 214 lb/month to 227 lb/month for two turbines.

- **Petition to Amend the Final Decision for the Malburg Generating Station (MGS) (01-AFC-25C)("Petition") submitted to the CEC on 11/21/17**

Bicent requests the following items in the Petition:

1. Modify Turbines No. 1 and 2 by installing the Siemens A+ turbine upgrade package to increase generation capacity and combustion turbine efficiency.

2. Conform the CEC License to the SCAQMD facility permit by revising four CEC Conditions of Certification to conform to the four underlying SCAQMD conditions for the SCR/CO catalysts systems for which updates were made during the Title V renewal process.

    a. Revise Condition of Certification AQ-12 to conform to condition A195.4 which had been revised to add a correction factor to the formula to calculate ammonia slip concentration.

    b. Revise Condition of Certification AQ-19 to conform to condition D12.4 which had been revised to require the ammonia injection rate to be maintained between 5 lb/hr and 175 lb/hr.

    c. Revise Condition of Certification AQ-20 to conform to condition D12.5 which had been revised to require the exhaust temperate at the inlet of the SCR/CO catalyst to be maintained between 350 degrees F and 750 degrees F, except during startups and shutdowns.

    d. Revise Condition of Certification AQ-21 to conform to condition D12.6 which had been revised to require the pressure drop to be maintained between 0.15 and 2.0 inches water column.

3. Revise Condition of Certification AQ-C7 to increase the limit for the PM_{10} emissions from the cooling tower from 6.2 lb/day to 7.3 lb/day.

    <u>Note</u>: The cooling tower remains exempt from permitting pursuant to Rule 219(d)(3), amended 5/5/17. As Rule 219(s)(2)(A), amended 5/5/17, requires a permit for exempt equipment for which the MICR is greater than 1 in a million, or the HIA or HIC is greater than 1.0, this evaluation will calculate the cooling tower PM_{10} emission rate for the turbine modification to confirm the proposed increase from 6.2 lb/day to 7.3 lb/day $PM_{10,}$ as well as provide a Rule 1401 risk assessment for the cooling tower.

    <u>Note</u>: Bicent Response Letter, 10/20/18, item 6.b.iii. acknowledged the water analysis indicated the Total Dissolved Solids of the cooling tower water was 1020 mg/liter, not the 1125 mg/l used to calculate the 7.3 lb/day. Therefore, based the correct 1020 mg/liter, the PM_{10} limit will be increased to 6.6 lb/day.

4. Revise Condition of Certification AQ-C8 as follows: "The project owner shall refrain from testing the firewater pump ~~on~~ **<u>during</u>** the same ~~day~~ **<u>hour</u>** as either gas fired combustion turbine~~s have been~~ **<u>is in</u>** start up or shutdown as defined by Condition of Certification AQ-C9." The Petition explained that this restriction is now overly burdensome since the needs of the electrical system cause the MGS to be dispatched more frequently than originally

contemplated during the original licensing proceeding. Bicent proposes to modify the restriction to allow testing of the fire pump on the same day as a startup or shutdown event but prohibit the testing during the same hour as the startup and shutdown event.

TURBINE EQUIPMENT DESCRIPTION UPDATES ON FACILITY PERMIT

The following changes will be made to the turbine equipment description as a result of the turbine upgrade project.

1) Make and Model No.—The turbines will be updated from Alstom Model GTX100 to Siemens SGT-800 with A-Plus Upgrade. When Siemens Power Corporation purchased Alstom Power, the Alstom GTX 100 was redesignated as Siemens SGT-800 to conform to Siemens' naming convention. See pp. 1-3 and 1-5 of Application.

2) Turbine and Generator Rating— In *Attachment 4* of the Application, *Table 1--Emissions and Operating Parameters for Gas Turbine*, dated 7/13/17, was provided by Siemens for the A-Plus Upgrade project for sixteen operating cases ("Siemens Table 1"). (The Application refers to operating scenarios as "cases," whereas the FDOC refers to "scenarios.") These are the same sixteen operating scenarios that were provided by Alstom for the FDOC. The ratings and emissions are highest for Scenario/Case S13 (100% load at 38 ºF ambient, duct burner on).

   Pursuant to Siemens Table 1 for Case S13, the A+ Turbine Upgrade will increase the turbine rating from 454.05 to 491.76 Btu/hr at 38 ºF. The duct burner rating will remain unchanged at 81.20 MMBtu/hr. The turbine output will increase from 44.2 MW gross to 48.4 MW gross.

3) Steam Turbine Generator (STG) Rating—P. 16 of the FDOC indicates the STG rating is 55 MW at 75 ºF but did not include the rating on the facility permit. Bicent Response Letter, 5/17/18, item 1 confirmed the rating is also 55 MW at 38 ºF (Case S13) because the STG has a maximum design rating of 55 MW. The 55 MW gross rating will be added to the facility permit.

PROCESS DESCRIPTION

1. **A/N 598922—Turbine Upgrade Modification to Turbine No. 1**
2. **A/N 598923—Turbine Upgrade Modification to Turbine No. 2**

A. Pre-Modification: A/N 517249 & 517250—Startup & Shutdown Revisions

- ***Combined-Cycle Turbines***

  The MGS is a natural-gas fired, combined-cycle electric power generating facility with two identical power units. Each power unit consists of a combustion turbine (CT), a combustion turbine generator (CTG), and a heat recovery steam generator (HRSG). The exhaust from each turbine flows into its HRSG, which produces steam from the waste heat

in the exhaust. The steam from the two HRSGs drives a shared steam turbine generator (STG).

From the current facility permit equipment description, each combustion turbine is rated at 454.05 MMBtu/hr at 38 deg F (Scenario S13), and each generator at 44.2 MW. Each HRSG is equipped with a duct burner rated at 81.2 MMBtu/hr. The steam turbine generator is rated at 55 MW gross (will be added to equipment description.)

Each CT is equipped with an inlet air cooler to control inlet air temperature and enhance turbine performance during hot weather. The cooled air is compressed prior to being fed to the combustor. The preheated natural gas is mixed with the compressed air and the mixture is ignited in the combustor. The high-pressure, high temperature gas produced in the combustion section is expanded through the turbine blades, which drive the turbine, the electric generator and the turbine compressor to produce electrical power. The turbine exhaust gas passes through insulated ducts to a horizontal HRSG. Steam produced in the HRSG rotates the shared steam turbine generator (STG) to produce electrical power. P. 12 of the FDOC indicates the net power output from the two combustion turbines (CTs) and the shared steam turbine generator (STG) is approximately 134 MW (net power output at annual average temperature of 65 °F and 50% relative humidity).

Each CT is equipped with built-in pollution controls consisting of dry low NOx (DLN) combustors to reduce NOx emissions. These DLN combustors reduce NOx emissions to approximately 22 ppmvd at 15% oxygen at the CTG exhaust by pre-mixing fuel and air immediately prior to combustion. Pre-mixing inhibits NOx formation by minimizing the flame temperature and the concentration of oxygen at the flame front. The DLN combustor reduces the CO and VOC emissions to 6 ppmvd and 3.6 ppmvd at 15% O_2, respectively.

Each HRSG is equipped with post combustion emissions controls for further reduction of NOx, CO and VOC emissions. The Selective Catalytic Reduction (SCR) system reduces NOx emissions to meet the BACT limit of 2 ppm (1-hr average). The SCR process uses ammonia (NH_3) as a reducing agent to catalytically convert NOx to molecular nitrogen (N_2) and water vapor. The unreacted ammonia concentration, known as ammonia slip, is limited to 5 ppm at 15% O_2. The SCR system includes a catalyst chamber, catalyst bed, and ammonia vaporization and injection systems, with the ammonia injection grid located upstream of the catalyst chamber. The CO oxidation catalyst reduces CO and VOC emissions to the BACT limits of 2 ppmv (3-hr average will be revised to 1-hr average, see *Rule 1303(a)(1)—BACT/LAER* analysis below) and 2 ppmv (1-hr average), respectively. The PM_{10} and SOx are controlled by the use of pipeline natural gas fuel, which is BACT for both.

- ***Rule 219 Exempt--Cooling Tower***
  The cooling tower, exempt from permitting per Rule 219(d)(3)(B), removes heat from the steam turbine's exhaust steam. The condensed water is returned to the HRSG feed water system for reuse. The cooling tower has three cells and is rated for 25,000 gpm. The loss of water from evaporation and drift is replenished with reclaimed water from the local water district.

B. Post-Modification: A/N 598922 & 598923-Turbine Upgrade

- ***Combined-Cycle Turbines***
  The A+ Turbine Upgrade will increase the turbine rating from 454.05 to 491.76 MMBtu/hr at 38 ºF (Case S13). The generator's output will increase from 44.2 to 48.4 MW gross at 38 ºF (Case S13). The duct burner rating will remain unchanged at 81.20 MMBtu/hr, and the steam turbine generator will remain unchanged at 55 MW gross.

  On p. 1-4, the Application for turbine upgrade provides a discussion of the equipment component changes, but does not discuss how the changes will increase power production.

  Bicent Response Letter, 5/17/18, item 2 provided clarification by first explaining the structure of the existing turbines. The SGT-800 is a single shaft engine that consists of inlet housing, 15 stage axial compressor, an annular serial cooled combustor, a 3-stage axial turbine and an outlet diffuser. The first three stages of the compressor are made of variable guide vanes. The combustor is equipped with Dry Low Emissions (DLE) dual fuel burners to reduce NOx, CO, and VOC. The first two turbine stages are air cooled. The stage 1 blades is constructed of a single crystal material.

  The upgrade will result in the redesign of the stage 1 vanes and blades [referred to below as Row 1 compressor blades] in the hot gas path along with an improved cooling system resulting from the redesign of vanes 1 and 2 [referred to below as Row 1 and Row 2 Vanes] which will result in an increase in turbine efficiency.

  From p. 1-4 of the Application, the upgrade package will install the following:

  - The Row 1 compressor blades will be replaced with a functionally different design to increase the air flow.

  During the installation of the upgrade package, the following components will be replaced as part of the normal repair cycle and are of a functionally equivalent like kind design:

  - The redesigned Row 1 Turbine Vanes and Blades will contain a new thermal barrier coating along with optimizing the placement and number of vent holes to reduce the metal temperature to accommodate the changes to heat and air flow

from the upgraded Row 1 compressor blades. Without the Row 1 compressor blades upgrade, the vanes and blades would function the same as the current setup.

- The redesigned Row 2 Vanes will also incorporate a new coating and additional vent holes to accommodate the changes to heat and air flow. Without the Row 1 compressor blades upgrade, the vanes and blades would function the same as the current setup.

- The Cooling Air System will be optimized.

The Bicent Response Letter, 5/17/18, further explains that the following design changes will result from the redesigned blades and vanes:

- The compressor efficiency will be improved due to the increase of the mass flow. The new compressor blade 1 [referred to above as Row 1 compressor blades] has a slightly opened profile but there will be no change in the blade material. Additionally, several improvements have been done on turbine blade 1 [referred to above as Row 1 Blade] which will include a new thermal barrier coating and the optimization of the number and positioning of the cooling holes which will result in a reduction of metal temperature.

- For vanes 1 and 2 [referred to above as Row 1 and Row 2 Vanes], the cooling air consumption has been optimized but the vane shape, vane material and vane coatings remain unchanged.

The enhanced performance is primarily the result of increased air mass flow and the optimized air cooling of the main turbine section. In addition to the increased mass flow, the new blade design also provides increased compressor efficiency and operating range in terms of pressure ratio and temperature. This results in improved compressor stability which would then allow the compressor to operate with fully open inlet guide vanes at higher ambient temperatures which will maintain a high mass flow and consequently, will allow for increased turbine output during hot ambient conditions.

The upgrade will result in a slight increase in the exhaust temperature along with a small increase in mass flow. Overall, the efficiency improvement of the turbine is expected to result in a two percent decrease in fuel consumption per kWh.

Further, Siemens Energy provided a letter, dated 2/9/18, regarding the Malburg performance upgrade (docketed as TN 222682 by the CEC). The letter explained that Phase I would include installation of the enhanced turbine and compressor blades. Phase II would consist of installing and tuning the engineering software necessary to achieve the

performance upgrade. In an e-mail, dated 3/29/18, Kyle McCormack, Environmental Manager, explained that Phase II involves the installation of an A+ logic-based software update, which has been engineered to modify certain operational parameters of the gas turbine to increase performance. This software change can only be installed by Siemens engineers as the logic system is locked. The installation will require the shutdown and re-programming of the gas turbines primary fuel and emissions systems.

- ***Rule 219 Exempt--Cooling Tower***

  P. 4-9 of the Petition states: "As shown in Table 1 [Summary of Maximum Proposed Facility Emissions], there is an additional increase in PM10 emissions from the cooling tower due to the increase in water circulation to provide the additional heat rejection necessary to accommodate the increase in generation. Therefore, we propose the following modification to Condition of Certification AQ-C7.

  AQ-C7 PM10 emissions from the cooling tower (in total) shall not exceed ~~6.2~~ ***7.3*** lb/day."

  P. 1-6 of the Application indicates that the cooling tower circulating pumps will be run at a slightly higher capacity to handle the increased heat rejection from the modified turbines. The total dissolved solids (TDS) in the cooling tower will also be revised from 4,000 milligrams/liter (mg/l) to reflect a 4,500 mg/l concentration. P. 1-26 indicates that the pumps on the cooling tower will be removed and replaced with new higher capacity units. In *Attachment 3* of the Application, *Table 5—Cooling Towers-Wet Surface Condensers*, the circulation rate is shown as 26,952.4 gal/min, increased from the original 25,000 gal/min (p. 29 of FDOC).

  Bicent Response Letter, 5/17/18, item 6.b.i. provided the basis for the derivation of the 26,952.4 gal/min. Item 6.b.ii. provided the water analysis that was the basis for the 4,500 mg/l concentration. The water analysis indicated the total dissolved solids was 1020 mg/l TDS. Bicent Response Letter, 10/20/18, item 6.b.iii, acknowledged the 1125 mg/l, used to derive the 4,500 mg/l TDS and the proposed 7.3 lb/day, was incorrect. Based on the correct 1020 mg/l, the concentration is 4080 mg/l concentration and the PM_{10} emission rate is 6.6 lb/day. ***Therefore, the PM_{10} limit should be increased from the current 6.2 lb/day to 6.6 lb/day, not 7.3 lb/day.***

EMISSIONS CALCULATIONS

1. **A/N 598922—Turbine Upgrade Modification to Turbine No. 1**
2. **A/N 598923—Turbine Upgrade Modification to Turbine No. 2**

CRITERIA POLLUTANTS

The emissions calculations will be discussed below for:

A. Initial Emissions: A/N 394164 & 394165—FDOC,
B. Pre-Modification Emissions: A/N 517249 & 517250—Startup & Shutdown Revisions, and
C. Post-Modification Emissions: A/N 598922 & A/N 598923--Turbine Upgrade

A. Initial Emissions: A/N 394164 & 394165—FDOC

The 30-day average emissions for CO, ROG, PM_{10} and SOx per turbine were initially determined in the FDOC. The 30-day averages for CO, ROG, and SOx were based on the *SCAQMD Standard Procedure—Maximum Monthly Emissions* methodology. The 30-day average for the PM_{10} emissions, however, was based on the *Applicant Analysis for Offset Requirements* methodology which resulted in the imposition of condition C1.4. This condition limited the fuel usage to no more than 330 MM cubic feet in any one calendar month per turbine for the purpose of ensuring that the total PM_{10} emission shall not exceed 2,438 lbs/month per turbine. As MGS is a RECLAIM facility, the maximum annual NOx emissions determined the RTC holding requirements per turbine.

The 30-day average emissions for CO, ROG, PM_{10} and SOx per turbine were based on the higher of the emissions for a commissioning month (highest of any commissioning month) or a normal operating month. Therefore, the commissioning month emissions and normal operating month emissions were required to be calculated to allow a comparison. The calculations are reproduced below.

1) Commissioning Emissions

Commissioning is a one-time event that occurs between the installation of a turbine and the beginning of commercial operation. During commissioning, the facility follows a systematic approach to optimize the performance of the CTG and associated control equipment. Tests are performed on the units to verify performance and make necessary adjustments.

The commissioning of each CTG was proposed to take place over 74 days. The commissioning for the two CTGs would take place over three months, with the commissioning of the second unit beginning 15 days after the start of the commissioning of the first unit and lasting through the 89th day of the commissioning period. As the CO catalysts were installed prior to the commissioning period, the CO and VOC emissions were controlled during the commissioning.

The following table shows the commissioning period emissions for each CTG unit as provided by the manufacturer. [See FDOC, pg. 28.]

Table 4 – Commissioning Emissions (A/N 394164 & 394165-FDOC)

Pollutant	1st Month Emissions, lbs			2nd Month Emissions, lbs			3rd Month Emissions, lbs		
	Turbine 1	Turbine 2	Total	Turbine 1	Turbine 2	Total	Turbine 1	Turbine 2	Total
NOx	**1,999**	**1,584**	3,583	1,001	848	1,849	699	1,267	1,966
CO	2,728	965	3,693	**3,521**	**4,112**	7,633	933	2,105	3,038
PM_{10}	280	122	402	555	303	858	**567**	**977**	1,544
VOC	**1,765**	**1,471**	3,236	1,529	690	2,219	192	1,325	1,517
SOx	16	9	25	**23**	14	37	22	**38**	60

Ref: Data from Appendix A-1, Revised Supplement for Application for P/C-P/O, dated July 18, 2002

The highest commissioning emissions for Turbines 1 and 2 are shown in bold font in the table above.

NOx <u>Commissioning first month</u>
Turbine 1: 1999 lb/month / 30 days = 66.63 lb/day → 67 lb/day
Turbine 2: 1584 lb/month / 30 days = 52.80 lb/day → 53 lb/day

CO <u>Commissioning second month</u>
Turbine 1: 3521 lb/month / 30 days = 117.36 lb/day → 117 lb/day
Turbine 2: 4112 lb/month / 30 days = 137.07 lb/day → 137 lb/day

PM_{10} <u>Commissioning third month</u>
Turbine 1: 567 lb/month / 30 days = 18.90 lb/day → 19 lb/day
Turbine 2: 977 lb/month / 30 days = 32.57 lb/day → 33 lb/day

VOC <u>Commissioning first month</u>
Turbine 1: 1765 lb/month / 30 days = 58.83 lb/day → 59 lb/day
Turbine 2: 1471 lb/month / 30 days = 49.03 lb/day → 49 lb/day

SOx <u>Commissioning second month (Turbine 1) / third month (Turbine 2)</u>
Turbine 1: 23 lb/month / 30 days = 0.77 lb/day → 1 lb/day
Turbine 2: 38 lb/month / 30 days = 1.27 lb/day → 1 lb/day

2) <u>Normal Operating Emissions</u>

The SCAQMD calculated the normal operating emissions based on the *<u>SCAQMD Standard Procedure-Maximum Monthly Emissions</u>* methodology. After reviewing the SCAQMD emissions calculations, the applicant proposed the *<u>Applicant Analysis for Offset Requirements</u>* methodology to reduce the number of emission reduction credits (ERCs) required for CO, PM_{10} and VOC. The SCAQMD accepted the second methodology for

PM_{10} emissions only, because the ERCS required for CO and VOC ERCs were based on the highest commissioning month emissions which were higher than normal operating month emissions.

a) <u>SCAQMD Standard Procedure—Maximum Monthly Emissions</u>

The following emissions calculations were performed pursuant to the standard procedure to determine maximum monthly emissions for turbines. The facility requested a maximum of 56 total startups, 4 cold starts and 52 warm/hot starts for a year. The SCAQMD assumed one cold start, 4 warm/hot starts and 5 shutdowns for the maximum emissions month.

Alstom provided data for thirteen operating scenarios corresponding to a full range of possible turbine loads, ambient temperatures, and duct burner status for normal operation. Scenario S13 (100% load at 38 °F ambient, duct burner on) provided the highest hourly emissions (highest exhaust gas flowrate). The operating parameters and emission rates for Scenario S13 are summarized in the table below. [See FDOC, pp. 21 - 22.] The controlled PM_{10} emissions rate is higher than the uncontrolled emission rate because 53% of the SO_2 in the turbine exhaust is assumed to convert to SO_3 in the CO catalyst and SCR. The SO_3 reacts with ammonia in the SCR to form ammonium sulfate particulates. Thus total PM_{10} is comprised of the ammonium sulfate particulates and the PM_{10} in the turbine exhaust.

Table 5 – Scenario S13 Operating Parameters and Emission Rates (A/N 394164 & 394165-FDOC)

Scenario No.	Load %	Ambient Temp °F	Duct Burner	Heat Input		Fuel Flow Rate, mmscf/hr	Exhaust Flow Rate, scf/hr
				mmbtu/hr	mmscf/hr		
S13	100	38	On	535.27	0.526	0.526	16.84

	Ppmvd @ 15% O_2		lb/mmbtu		lb/mmcf		lb/hr	
	Uncntrld	Cntrld	Uncntrld	Cntrld	Uncntrld	Cntrld	Uncntrld	Cntrld
NOx	22	2	0.0839	0.0076	85.38	7.76	44.91	4.08
CO	6	2	0.0139	0.0046	14.16	4.71	7.45	2.48
PM_{10}	---	---	0.0066	0.0073	6.72	7.39	3.53	3.89
VOC	3.6	1.2	0.0048	0.0016	4.87	1.62	2.56	0.85
SOx	---	---	0.00059	0.00028	0.60	0.28	0.32	.015
NH_3	---	5	---	0.0070	---	7.17	---	3.80

Ref: Data from Appendix A-5, S-13, Revised Supplement for Application for P/C – P/O, dated July 18, 2002

Alstom provided startup emissions per event, as shown in the table below. [See FDOC, p. 23.] Cold start occurs after more than 72 hours of shutdown. Warm start occurs between 8 and 72 hours inclusive of shutdown. Hot start occurs within 8 hours of shutdown. During startup, NOx, CO, and VOC will be higher because the dry low NOx combustor is not effective until the CTG reaches 50% load, and the SCR is not effective

until the minimum operating temperature is reached. For PM_{10} and SOx, the startup emissions reflect the gas usage for the event and the emission factor (lb/mmscf) remains constant.

Table 6 – Startup Emissions (A/N 394164 & 394165-FDOC)

Time Period	Fuel Use, scf/period	NOx, lb/period	CO, lbs/period	VOC, lbs/period	PM_{10} lbs/period	SOx lbs/period
2 hr cold start	596,600	15.75	24.5	1.75	4.37	0.2
1.5 hr warm start	501,000	13.43	9.95	1.55	3.65	0.16
1 hr hot start	334,000	8.11	6.63	1.04	N/A	N/A

Ref: Data from Appendices A2, A3, and A4, Scenarios C1, W1 & H1, Revised Supplement for Application for P/C-P/O, dated July 18, 2002.

Alstom provided shutdown emissions per event, as shown in the table below.

Table 7 – Shutdown Emissions (A/N 394164 & 394165-FDOC)

Time Period	NOx, lb/period	CO, lb/period	VOC lb/period	PM_{10} lb/period	SOx lb/period
0.5 hr shutdown	5.51	4.75	0.71	0.92	0.03

Ref: Data from Appendices A6, Tables SH1, SH2, SH3, Revised Supplement for Application for P/C-P/O, dated July 18, 2002.

Operating Schedule: 52 wk/yr, 7 days/wk, 24 hr/day

As stated above, the SCAQMD assumed one cold start, 4 warm starts and 5 shutdowns for a maximum emissions month. One month = 30 days = 720 hours. The remaining hours of operation (709.5 hrs as calculated below) will be in normal operating mode for Scenario S13.

Normal hrs of operation = 720 hrs – [one cold start (2 hrs) + 4 warm startups (1.5 hrs each) + 5 shutdowns (0.5 hr each)] = 709.5 hrs

NOx

NOx emissions calculations are provided below for informational purposes. The number of RTCs required is calculated under the *Rule 2005(b)(2)--Offsets* analysis.

Maximum monthly emissions = (15.75 lb/cold start)(1 cold start) + (13.43 lb/warm start)(4 warm startups) + (5.51 lb/shutdown) (5 shutdowns) + (4.08 lb/hr normal operation)(709.5 hr) = 2992 lb

30 DA = 2992 lb/30 days = 99 lb/day

CO
Maximum monthly emissions = (24.5 lb/cold start)(1 cold start) +
(9.95 lb/warm start)(4 warm starts) + (4.75 lb/shutdown) (5 shutdowns) +
(2.48 lb/hr normal operation)(709.5 hr) = 1848 lb

30 DA = 1848 lb/30 days = 61.6 lb/day → 62 lb/day

PM_{10}
Maximum monthly emissions = (4.37 lb/cold start)(1 cold start) +
(3.65 lb/warm start)(4 warm starts) + (0.92 lb/shutdown) (5 shutdowns) +
(3.89 lb/hr normal operation)(709.5 hr) = 2784 lb

30 DA = 2784 lb/30 days = 92.8 lb/day → 93 lb/day

VOC
Maximum monthly emissions = (1.75 lb/cold start)(1 cold start) +
(1.55 lb/warm start)(4 warm starts) + (0.71 lb/shutdown) (5 shutdowns) +
(0.85 lb/hr normal operation)(709.5 hr) = 615 lb

30 DA = 615 lb/30 days = 20.5 lb/day → 21 lb/day

SOx
Maximum monthly emissions = (0.2 lb/cold start)(1 cold start) +
(0.16 lb/warm start)(4 warm starts) + (0.03 lb/shutdown) (5 shutdowns) +
(0.15 lb/hr normal operation)(709.5 hr) = 107 lb

30 DA = 107 lb/30 days = 3.57 lb/day → 4 lb/day

b) Applicant Analysis for Offset Requirements (Condition C1.9)

Pursuant to the *SCAQMD Standard Procedure—Maximum Monthly Emissions* methodology shown above, the maximum PM_{10} emission rate of 3.89 lb (Scenario S13) would have resulted in 2784 lb/month PM_{10} for one turbine, and 5568 lb/month PM_{10} for two turbines.

From p. 87 of the FDOC, the 3.89 lb/hr PM10 is equal to 7.397 lb/mmscf. The 2784 lb/month per turbine would have corresponded to 376 mmscf/month per turbine, calculated as follows:

Maximum monthly fuel usage for PM_{10} = (2784 lb/month per turbine)

(mmscf/7.397 lb) = 376.4 mmscf/month per turbine

Based on the 30-day average of 93 lb/day PM_{10} per turbine and an offset factor of 1:1 for the Priority Reserve, 186 lb/day of PM_{10} offsets would have been required for the two turbines. If the applicant, Vernon City, Light & Power Dept., had agreed to provide 186 lb/day PM_{10} offsets, condition A63.3 would have limited PM_{10} emissions to 5568 lb/month for the total combined emissions for the two turbines and included a PM_{10} emission factor of 7.397 lbs/mmscf. The monthly limits and emission factors for PM_{10} and SOx would have determined the maximum fuel usage allowed, which would have been 376 mmscf/month per turbine. Since the monthly limits for CO and VOC were based on maximum commissioning emissions, neither would have resulted in the maximum fuel usage allowed for normal operations. A separate condition C1.4 limiting fuel usage would not have been added to the facility permit for clarification.

However, when the SCAQMD informed the applicant that 186 lbs/day of PM_{10} offsets would be required based on the *AQMD Standard Procedure—Maximum Monthly Emissions* methodology, the consultant provided six operating scenarios for offset requirements for CO, VOC, and PM_{10} for the purpose of reducing offset requirements. Offsets would not be required for SOx emissions which were below the 4 tpy threshold for offsets. The CO, PM_{10}, and VOC emissions for the six scenarios are summarized in Table L2-- Monthly Emissions for Six Operating Scenarios on p. 90 of the FDOC. The SCAQMD accepted Scenario No. 1 of the six operating scenarios provided for the purpose of reducing PM_{10} offsets only. The SCAQMD based the CO and VOC emission offsets on commissioning emissions, which are higher than normal operation emissions. Scenario No. 1 was based on 240 hours of normal operation with duct burner per month, 480 hours of normal operation without duct burner per month, and no startups or shutdowns, during the summer season with an ambient temperature of 65 °F.

Consultant Krishna Nand's e-mail, dated 10-18-02, provided the emissions calculation and fuel usage for PM_{10} as follows:

Maximum monthly emissions (at 65 °F ambient) = (3.78 lb/hr with duct burner)(240 hr) + (3.19 lb/hr without duct burner) (480 hr) = 2438 lb/month

30 day average = 2438 lb/30 days = 81 lb/day

Maximum monthly fuel usage (at 65 °F) = (0.511 mmscf/hr with duct burner)(240 hr) + (0.432 mmscf/hr without duct burner) (480 hr)
= 330 mmscf/month

Consequently, the SCAQMD revised draft condition A63.3 to reduce the monthly limit for PM_{10} from 5568 lb/month to 4876 lb/month per two turbines but retained the

emission factor of 7.397 lbs/mmscf. The SCAQMD also added condition C1.4 to limit the fuel usage to 330 MM cubic feet in any calendar month per turbine. The applicant provided 182 lb/day (81 lb/day per turbine) of priority reserve credits from the Priority Reserve pursuant to Rule 1309.1 because sufficient PM_{10} ERCs could not be found on the market.

Note: Condition A63.3 limited SOx to 214 lb/month for two turbines, and included a SOx emission factor of 0.28 lb/mmscf. The imposition of the 330 cf/month per turbine in effect limited the SOx emissions to 185 lb/month for two turbines.

3) Bases for 30-Day Averages

The 30-day average for each criterion pollutant was based on the higher of the emissions for a commissioning month (highest commissioning month) or a normal operating month. The normal operating month emissions were calculated using two methodologies, as discussed above.

The 30-day averages for each turbine and the basis for the 30-day averages are summarized in the table below. [See FDOC, pg. 94]

Table 8 – Basis for 30-Day Averages (A/N 394164 & 394165-FDOC)

Pollutant	Turbine 1 30-day Avg, lb/day	Turbine 2 30-day Avg, lb/day	Bases for 30-day Averages
NOx	99	99	Normal operating emissions per *SCAQMD Standard Procedure for Calculating Maximum Monthly Emissions* (Scenario S13) for informational purposes as this is a RECLAIM facility. Note: Maximum normal operating month emissions higher than commissioning month emissions of 67 lb/day for Turbine 1 and 53 lb/day for Turbine 2.
CO	117	137	Commissioning period, 2nd month Note: Commissioning month emissions higher than maximum normal operating month emissions of 62 lb/day.
PM_{10}	81	81	Normal operating emissions pursuant to *Applicant Analysis For Offset Requirements* per Scenario No. 1 (240 hours of normal operation with duct burner per month, 480 hours of normal operation without duct burner per month, and no startups or shutdowns, during the summer season with an ambient temperature of 65 °F.)

			Note: SCAQMD agreed to this methodology pursuant to Applicant's request to minimize PM_{10} offset requirements, instead of requiring the 93 lb/day pursuant to the *SCAQMD Standard Procedure—Maximum Monthly Emissions* methodology.
VOC	59	49	Commissioning period, 1st month Note: Commissioning month emissions higher than maximum normal operating month emissions of 21 lb/day.
SOx	4	4	Normal operating emissions pursuant to *SCAQMD Standard Procedure for Calculating Maximum Monthly Emissions* (Scenario S13) Note: Maximum normal operating month emissions higher than commissioning emissions of 1 lb/day.

4) Condition A63.3 Monthly Limits

Condition A63.3 sets forth monthly limits for CO, PM_{10}, VOC, and SOx. These limits were derived as follows:

CO: [(117.36 lb/day $_{\text{Turbine 1}}$ + 137.07 lb/day $_{\text{Turbine 2}}$)] (30 days) = 7633 lb/month

Daily emissions from commissioning second month.

PM_{10}: [(2438 lb/month $_{\text{Turbine 1}}$ + 2438 lb/month $_{\text{Turbine 2}}$)] = 4876 lb/month

Maximum monthly emissions from *Applicant Analysis for Offset Requirements*

VOC: [(58.83 lb/day $_{\text{Turbine 1}}$ + 49.03 lb/day $_{\text{Turbine 2}}$)] (30 days) = 3236 lb/month

Daily emissions from commissioning first month.

SOx: [(3.57 lb/day $_{\text{Turbine 1}}$ + 3.57 lb/day $_{\text{Turbine 2}}$)] (30 days) = 214 lb/month
Daily emissions from *SCAQMD Standard Procedure for Maximum Monthly Emissions*.

5) Condition A63.3 Emission Factors

As shown in Table J1--Criteria Pollutant's Emission Factors on p. 83 of the FDOC, the condition A63.3 emission factors for VOC, SOx, and PM_{10}, were calculated by dividing the average hourly emission rate by the average hourly gas usage (HHV), both based on

Scenario S15 (100% load, 65 ºF ambient, duct burner on). However, the maximum emissions month for derivation of the A63.3 limits were based on Scenario S13 (100% load, 38 °F ambient, duct burner on). The discrepancy in scenarios was not discussed in the FDOC. From p. 21 of the FDOC, the heat value is 1018 Btu/scf (HHV). (A CO emissions factor is not required because the emissions are based on CEMS data.)

The derivation of the emissions factors is shown below.

i. VOC Emission Factor
From FDOC, p. 83, Scenario S15
0.83 lb/hr ÷ 0.511 mmscfh = 1.63 lbs/mmscf

ii. SOx Emission Factor
From FDOC, p. 83, Scenario S15
0.14 lb/hr ÷ 0.511 mmscfh = 0.28 lbs/mmscf

iii. PM_{10} Emission Factor
From FDOC, p. 83, Scenario S15
3.78 lb/hr ÷ 0.511 mmscfh = 7.397 lbs/mmscf

6) New Source Review Database Entries - R1 and R2 Calculations

The NSR data summary sheet requires uncontrolled (R1) and controlled (R2) hourly and daily emissions rates. The following shows the calculations to derive the uncontrolled (R1) and controlled (R2) normal operating emission rate for each criteria pollutant. The startup and shutdown emissions were not taken into account.

For A/N 394164 & 394165, the permitting engineer entered the R1 and R2 values in the NSR Tracking System as shown below. However, the 30-day averages in NSR were **not** the 30-day averages calculated by the NSR Tracking System from the R2 emission rate. The engineer manually input the 30-day averages, which are based on the higher of the emissions for a commissioning month or a normal operating month (comprised of normal operating emissions, startups, and shutdown), using the override function.

Operating Schedule: 52 wk/yr, 7 days/wk, 24 hr/day

NOx

R1, lb/hr = (22 ppm x 10^{-6})(16.84 mmscf/hr)(lb mol/379.4 scf)(46 lb/lb mol) = 44.91 lb/hr

lb/day = (44.91 lb/hr) (24 hr/day) = 1077.84 lb/day

R2, lb/hr = (2 ppm x 10^{-6} BACT)(16.84 mmscf/hr)(lb mol/379.4 scf)(46 lb/lb mol)
= 4.08 lb/hr

lb/day = (4.05 lb/hr)(24 hr/day) = 97.92 lb/day

30 DA = 99 lb/day for Turbines 1 and 2

[Normal operating emissions, *Standard Procedure For Calculating Maximum Monthly Emissions* (Scenario S13)]

CO

R1, lb/hr = (6 ppm x 10^{-6})(16.84 mmscf/hr)(lb mol/379.4 scf)(28 lb/lb mol) = 7.45 lb/hr

lb/day = (7.45 lb/hr) (24 hr/day) = 178.8 lb/day

R2, lb/hr = (2 ppm x 10^{-6} BACT)(16.84 mmscf/hr)(lb mol/379.4 scf)(28 lb/lb mol)
= 2.48 lb/hr

lb/day = (4.05 lb/hr)(24 hr/day) = 59.52 lb/day

30 DA = 117 lb/day for Turbine 1
30 DA = 137 lb/day for Turbine 2

[Commissioning period, 2nd month]

PM_{10}

R1, lb/hr = (0.0066 lb/mmbtu AP 42) (1018 btu/scf HHV)(0.526 mmscf/hr) = 3.53 lb/hr

*Note: The 3.53 lb/hr is adjusted to 3.89 lb/hr to be the same as R2, because the **SCAQMD NSR Program (AEIS Data Sheet and NSR Data Summary Sheet)** will not allow an R1 that is less than the R2.*

lb/day = (3.89 lb/hr) (24 hr/day) = 93.36 lb/day

R2, lb/hr = (6.72 lb/mmscf from combustion + 0.67 lb/mmscf from 53% conversion of SOx to PM_{10} per applicant's data)(0.526 mmscf/hr) =
(7.39 lb/mmscf) (0.526 mmscf/hr) = 3.89 lb/hr

lb/day = (3.89 lb/hr)(24 hr/day) = 93.36 lb/day

30 DA = 81 lb/day for Turbines 1 and 2

[Normal operating emissions, *Applicant Analysis For Offset Requirements (Scenario No. 1)*]

ROG

R1, lb/hr = (3.6 ppm x 10^{-6})(16.84 mmscf/hr)(lb mol/379.4 scf)(16 lb/lb mol) = 2.56 lb/hr

lb/day = (2.56 lb/hr) (24 hr/day) = 61.44 lb/day

R2, lb/hr = (1.2 ppm x 10^{-6} manufacturer's guarantee)(16.84 mmscf/hr)
(lb mol/379.4 scf)(16 lb/lb mol) = 0.85 lb/hr

lb/day = (0.85 lb/hr)(24 hr/day) = 20.4 lb/day

Note: The above calculations were based on the pre- and post-control concentration levels for ROG provided by Alstom. Nevertheless, SCAQMD BACT for VOC was 2 ppm at 15% O_2, 1-hour average, based on District Method 25.3/modified Method 25.3, as set forth in condition A195.3.

30 DA = 59 lb/day for Turbine 1
30 DA = 49 lb/day for Turbine 2

[Commissioning period, 1st month]

<u>SOx</u>
R1, lb/hr = (0.60 lb/mmscf EFB)(0.526 mmscf/hr) = 0.32 lb/hr
lb/day = (0.32 lb/hr) (24 hr/day) = 7.68 lb/day

R2, lb/hr = (0.28 lb/mmscf per applicant based on 0.5 gr/100 scf)(0.526 mmscf/hr) = 0.15 lb/hr
lb/day = (0.15 lb/hr)(24 hr/day) = 3.6 lb/day

30 DA = 4 lb/day for Turbines 1 and 2

[Normal operating emissions, <u>*Standard Procedure for Calculating Maximum Monthly Emissions*</u> (Scenario S13)]

◆◆

B. <u>Pre-Modification Emissions: A/N 517249 & 517250--Startup & Shutdown Revisions</u>

The revised cold start, non-cold start, and shutdown emissions limits, as well as the revised number of cold starts, non-cold starts, and shutdowns allowed per year did not change the 30-day average emissions, as shown below. The 30-day averages for CO, ROG, PM_{10} and SOx remained the same as for <u>A/N 394164 & 394165--FDOC</u>. The annual RTC holding requirements per turbine were increased.

As discussed above, the 30-day average for each criterion pollutant is based on the higher of the emissions for a commissioning month (highest commissioning month) or normal operating month.

1) <u>*Commissioning Emissions*</u>

As additional commissioning was not required, the commissioning emissions are from the FDOC.

2) Normal Operating Emissions

As for the FDOC, the normal operating emissions were calculated using two different methodologies: *a) AQMD Standard Procedure-Maximum Monthly Emissions*, and *b) Applicant Analysis for Offset Requirements* for PM_{10} only.

a) AQMD Standard Procedure—Maximum Monthly Emissions

The following emissions calculations were performed pursuant to the standard procedure to determine the monthly maximum emissions for turbines.

Operating Schedule: 52 wk/yr, 7 days/wk, 24 hr/day

A/N 517249 & 517250 requested a maximum of two startups and two shutdowns per day during a period not to exceed five days per year (within a 30 day window of time) during which required annual maintenance is conducted.

This translates to 5 cold starts, 5 warm starts and 10 shutdowns for a maximum emissions month. One month = 30 days = 720 hours. The remaining hours of operation (697.5 hrs as calculated below) will be in normal mode based on Scenario S13.

Normal hrs of operation = 720 hrs – [five cold start (2 hrs) + 5 warm startups (1.5 hrs each) + 10 shutdowns (0.5 hr each)] = 697.5 hrs

NOx

NOx emissions calculations are provided below for informational purposes. The number of RTCs required is calculated under the *Rule 2005(b)(2)--Offsets* analysis.

Maximum monthly emissions = (122.8 lb/cold start)(5 cold starts) + (51.3 lb/warm startup)(5 warm startups) + (4.5 lb/shutdown) (10 shutdowns) + (4.08 lb/hr normal operation)(697.5 hr) = 3761.3 lb

30 DA = 3761.3 lb/30 days = 125.37 lb/day → 125 lb/day

CO

Maximum monthly emissions = (204.8 lb/cold start)(5 cold starts) + (59.9 lb/warm start)(5 warm starts) + (10.8 lb/shutdown) (10 shutdowns) + (2.48 lb/hr normal operation)(697.5 hr) = 3161.3 lb

30 DA = 3161.3 lb/30 days = 105.37 lb/day → 105 lb/day

PM_{10}

Maximum monthly emissions = (4.37 lb/cold start)(5 cold starts) +

(3.65 lb/warm start)(5 warm starts) + (0.92 lb/shutdown) (10 shutdowns) + (3.89 lb/hr normal operation)(697.5 hr) = 2762.58 lb

30 DA = 2762.58 lb/30 days = 92.09 lb/day → 92 lb/day

VOC

Maximum monthly emissions = (1.75 lb/cold start)(5 cold starts) + (1.55 lb/warm start)(5 warm starts) + (0.71 lb/shutdown) (10 shutdowns) + (0.85 lb/hr normal operation)(697.5 hr) = 616.48 lb

30 DA = 616.48 lb/30 days = 20.55 lb/day → 21 lb/day

SOx

Maximum monthly emissions = (0.2 lb/cold start)(5 cold starts) + (0.16 lb/warm start)(5 warm starts) + (0.03 lb/shutdown) (10 shutdowns) + (0.15 lb/hr normal operation)(697.5 hr) = 106.73 lb

30 DA = 106.73 lb/30 days = 3.56 lb/day → 4.0 lb/day

b) Applicant Analysis for Offset Requirements (Condition C1.9)

This is the same as the FDOC, because this applicant analysis for offset requirements is applicable only to PM_{10} emissions. The startup and shutdown changes affected only NOx, CO, and VOC emissions.

3) Bases for 30-Day Averages

The table below is the same as *Table 8 – Basis for 30-Day Averages (A/N 394164 & 394165-FDOC)* above, except as noted. The 30-day averages did **not** change as a result of the startup and shutdown related changes, except for NOx which is provided for information purposes only.

Table 9 – Basis for 30-Day Averages
(A/N 517249 & 517250-Startup & Shutdown Revisions)

Pollutant	**Turbine 1 30-day Avg, lb/day**	**Turbine 2 30-day Avg, lb/day**	**Bases for 30-day Averages**
NOx	~~99 (FDOC)~~ **125**	~~99 (FDOC)~~ **125**	Normal operating emissions per *Standard Procedure for Calculating Maximum Monthly Emissions* (Scenario S13)—Provided for informational purposes as this is a RECLAIM facility. Note: Maximum normal operating month emissions higher than commissioning month emissions of 67 lb/day for Turbine 1 and 53 lb/day for Turbine 2.
CO	117	137	Same as A/N 394164 & 394165—FDOC.
PM_{10}	81	81	Same as A/N 394164 & 394165—FDOC.
VOC	59	49	Same as A/N 394164 & 394165—FDOC.
SOx	4	4	Same as A/N 394164 & 394165—FDOC.

4) ***Condition A63.3 Monthly Limits***
Same as A/N 394164 & 394165-FDOC.

5) ***Condition A63.3 Emission Factors***
Same as A/N 394164 & 394165-FDOC.

6) ***New Source Review Database Entries - R1 and R2 Calculations***
For A/N 394164 & 394165—FDOC above, the R1 and R2 entries were the uncontrolled and controlled normal operating emissions rates. The startup and shutdown emissions were not taken into account. However, the 30-day averages in NSR were **not** the 30-day averages calculated by the NSR Tracking System from the R2 emission rate. The engineer manually input the 30-day averages, which are based on the higher of the emissions for a commissioning month or a normal operating month (comprised of normal operating emissions, startups, and shutdown), using the override function.

R1, R2, and 30-day averages were the same as for A/N 394164 & 394165-FDOC, except the 30-day average for NOx increased from 95 lb/day to 125 lb/day.

◆◆

C. Post-Modification Emissions: A/N 598922 & 598923--Turbine Upgrade

As discussed above for the TURBINE EQUIPMENT DESCRIPTION UPDATES ON FACILITY PERMIT section, in *Attachment 4* of the Application, *Table 1--Emissions and Operating Parameters for Gas Turbine, dated 7/13/17* was provided by Siemens for the turbine upgrade project for sixteen operating cases ("Siemens Table 1"). (The Application refers to operating

scenarios as "cases," whereas the FDOC refers to "scenarios.") These are the same sixteen operating scenarios that were provided by Alstom for the FDOC.

The sixteen operating scenarios corresponds to a full range of turbine loads and ambient temperatures, which bound the expected normal operating range of each turbine. The operating scenarios are for three load conditions (60%, 80%, 100%) at four ambient temperatures (38 ºF, 59 ºF, 65 ºF, and 94 ºF), with and without evaporative cooling of the inlet air to the turbine, and with and without duct burner on.

The FDOC referred to Scenarios S13 and S15. The maximum normal operating month emissions and the RECLAIM Trading Credits (RTC) holding requirements were based on Scenario S13 (100% load, 38 ºF ambient, duct burner on). The condition A63.3 emission factors were based on Scenario S15 (100% load, 65 ºF ambient, duct burner on). The air dispersion modeling was based on maximum emissions for Scenario S13. The scenarios for the stack parameters were not discussed.

For the turbine upgrade, the maximum normal operating month emissions and the condition A63.3 emissions factors will be based on Case S13. The RTC holding requirements will be based on Case S15. (The selection of the case/scenario basis is based on current permitting practice.) As discussed below, the emissions and stack parameters for the air dispersion modeling are based on Cases S1, S11, S13, S14, and S15 for the various operating scenarios and averaging periods.

As Cases S1, S11, S13, S14, and S15 are referenced in this evaluation, the operating scenarios data for these cases from Siemens Table 1 are summarized in the table below.

Table 10 –Turbine Operating Scenarios (A/N 59822 & 598923-Turbine Upgrade)

Case	1) S1	11) S11	13) S13	14) S14	15) S15
Ambient Temperature (°F)	38	65	38	59	65
Turbine Load	60%	100%	100%	100%	100%
Evaporative Cooler	Off	On	Off	On	On
Duct Burner Status	Off	Off	On	On	On
Combustion Turbine Performance					
Turbine Heat Input, MMBtu/hr (HHV)	345.89	474.61	491.76	480.12	474.61
Turbine Heat Input, MMBtu/hr (LHV)	312	428	443.39	432.90	428
Duct Burner Heat Input, MMBtu/hr (HHV)	-	-	81.2	81.1	81
Gross Turbine Output (kW), installed no auxiliaries	29.052	46.493	48.420	47.154	46.493
Net Turbine Output (kW), minus auxiliary power	28.949	46.398	48.335	47.059	46.398
Stack Parameters					
Stack Exit Temperature, °F	216	236	226	220	221
Stack Diameter, ft	12	12	12	12	12
Stack Exit Velocity, ft/sec	31.35	46.08	46.71	45.42	45.09
Turbine Outlet/Catalyst Inlet Concentrations					
NOx, ppmvd (dry, 15% O_2)	15.00	15.00	15.00	15.00	15.00

CO, ppmvd (dry, 15% O_2)	3.00	3.00	3.00	3.00	3.00
VOC, ppmvd (dry, 15% O_2)	2.00	2.00	2.00	2.00	2.00
Catalyst Outlet/Stack BACT Concentrations & Emissions Rates					
NOx, 2.0 ppmvd (dry, 15% O_2) BACT, lb/hr as NO_2	2.516	3.460	4.158	4.115	4.078
CO, 2.0 ppmvd (dry, 15% O_2) BACT, lb/hr	1.532	2.106	2.529	2.503	2.480
VOC, 2.0 ppmvd (dry, 15% O_2) BACT, lb/hr	0.525	0.722	0.869	0.860	0.852
$PM_{10}/PM_{2.5}$, lb/hr (including 53% conversion of SOx to PM_{10} to form ammonium sulfate)	1.282	1.763	2.407	2.385	2.366
SOx, lb/hr (including 53% reduction of SOx used to form PM_{10})	0.097	0.133	0.160	0.157	0.156
NH_3 slip, 5.0 ppmvd (dry, 15% O2) BACT, lb/hr	2.325	3.197	3.841	3.802	3.767

The following provides clarifications for Siemens Table 1.

- **<u>VOC controlled emission rate versus BACT limit</u>**
  On p. 17 of the FDOC, *Table 3—CO Oxidation Catalyst Specifications* shows that the guaranteed controlled VOC is 1.2 ppm and 0.85 lb/hr. On p. 22, *Table 6—Turbine Emission Factors* shows uncontrolled VOC is 3.6 ppm and controlled VOC is 1.2 ppm. On p. 25, *Table 10—Turbine's Maximum Daily Emissions* shows the emissions calculations were based on the 1.2 ppm and 0.85 lb/hr (Scenario S13). However, on p. 38, *Table 20—Required BACT Standard* shows VOC BACT is 2 ppmvd at 15% O_2. The SCAQMD BACT limit was 2.0 ppmvd at 15% O_2 based on SCAQMD Method 25.3 at the time of the FDOC and remains 2.0 ppmvd today based on modified Method 25.3. The current permitting practice is to require the emission rate to be adjusted upward to be equal to the 2 ppm limit, but the FDOC accepted the emission rates based on 1.2 ppm. This acceptance did not affect the 30-day average for VOC because the 30-day average was based on the maximum commissioning month emissions, which was significantly higher than the maximum normal operating month emissions.

  For the turbine upgrade project, Siemens Table 1 shows the maximum VOC concentration is 1.2 ppmvd at 15% O_2 and 0.869 lb/hr (Case S13). Consistent with the FDOC, the emission rates from the table will be used, without adjusting the rates upward to be equal to 2 ppmvd at 15% O_2.

- **<u>PM_{10} Emission Rate</u>**
  On p. 26 of the FDOC, *Table 11--Maximum Controlled Emissions* shows the maximum PM_{10} emission rate is 3.89 lb/hr for 1 turbine with duct burner based on Scenario S13 (100% load at 38 ºF). For the turbine upgrade project, Siemens Table 1 shows the "Total PM10 with 53% conversion of SOx to PM10" is 2.407 lb/hr for Case S13 (100% load at 38 ºF). As discussed below, the SCAQMD will accept a reduction to 3.386 lb/hr for the turbine upgrade project.

- **SOx Emission Rate**

  P. 87 of the FDOC indicates the uncontrolled SOx factor was based on 0.60 lb/mmscf (default AER) or 0.32 lb/hr (S13). The controlled SOx factor reflects that 53 mole % of SO_2 in the turbine exhaust was assumed to oxidize to SO_3 in the CO catalyst and SCR. SO_3 reacts with ammonia in the SCR to form ammonium sulfate particulates. Therefore, total PM_{10} is comprised of the PM_{10} in the turbine exhaust and the ammonium sulfate particulates. The uncontrolled emission factor was reduced by an assumed 53% conversion to arrive at a controlled SOx factor of 0.28 lb/mmscf or 0.15 lb/hr.

  The current permitting practice is to base the monthly SOx emissions on 0.75 gr/100 scf because Southern California Gas Company, Rule No. 30-Transportation of Customer-Owned Gas allows up to 0.75 gr. S/100 scf total sulfur, unless otherwise proposed by the applicant and accepted by the SCAQMD. In addition, the SOx emission rate is not reduced by the molar percentage that is assumed to be converted to SO_3. However, the FDOC accepted the SOx emission rate with the 53% reduction.

  For the turbine upgrade project, Siemens Table 1 shows the SOx emission rate with the 53% reduction. Consistent with the FDOC, the emission rates from the table will be used.

Revisions Proposed

P. 1-26 of the Application states: "As summarized in Table 12 [Pre- and Post- Modification Emissions Comparison], for the monthly emissions of CO, VOC's, SOx and PM10/2.5, the applicant is not proposing any changes to existing condition A63.3 with the exception of the emission factors for compliance monitoring of PM_{10}, VOC and SOx and the revision of the monthly fuel limit to reflect the increased fuel requirements for the turbine upgrade."

As the Application does not propose any revised condition A63.3 emission factors, the emission factors will be calculated below.

Contrary to the statement above which states that the monthly fuel limit will be increased to reflect the increased fuel requirements for the turbine upgrade, Bicent Response Letters, 5/17/18 and 10/20/18, provided confirmation that Bicent is indeed requesting to increase the operating hours from 645.8 hr/month to 720 hr/month (30 days x 24 hr/day) with an associated increase in the monthly fuel limit.

The following proposed revisions will affect the emissions calculations.

1. Increase the operating hours per month per turbine from 645.8 hr/month (330 ft^3/month x hr/0.511 mmscf) to 720 hr/month.

2. Increase the condition C1.4 monthly fuel limit from 330 mmcf/month to 405.24 mmcf/month per turbine.

3. Increase the existing SOx limit in condition A63.3 from 214 lb/month to 227 lb/month for two turbines.

As discussed above, the 30-day average for each criterion pollutant is based on the higher of the emissions for a commissioning month (highest commissioning month) or normal operating month.

1) <u>Commissioning Emissions</u>

As discussed above, the maximum commissioning month emissions were established in the FDOC based on the initial commissioning of the turbines, which took place over two months for each turbine.

- **<u>Commissioning after Turbine Upgrade</u>**

  A less extensive commissioning process than for the FDOC will be required for the turbine upgrade project. The FDOC did not include a permit condition to limit the commissioning process. In more recent years, however, the EPA has accepted an alternative BACT which limits and minimizes emissions during periods when steady state BACT is not achievable, such as during commissioning, in lieu of requiring steady state BACT at all times. To that end, permit condition requirements for the commissioning of the two turbines after the turbine upgrade are discussed below.

  P. 1-4 of the Application indicates that, as the commission activities associated with the upgrade will occur over an approximate two- to three-week period, the proposed project will still safely allow for full compliance with the existing monthly emission limits in condition A63.3. P. 1-36 of the Application indicates that the commissioning activities associated with the upgrade package will occur over a period of two weeks.

  Bicent Response Letter, 5/17/18, item 7.a.i. clarified that the commissioning after the turbine upgrade will be based on the commissioning schedule with emissions, fuel use, and hours for each activity that was provided by Siemens in support of Case No. 5727-4 for the petition for short variance submitted on 4/5/18. A short variance was required for relief from conditions A99.3, A99.4, A99.5, A195.1, A195.2, and A195.3 for the commissioning required after the upgrade of the facility's control system during the scheduled annual spring outage in April.

  Engineering Manager Kyle McCormack provided an e-mail, dated 3/29/18, to discuss the differences between the variance request and the permit revision for turbine upgrade, as follows:

  - Variance request--As part of the normal turbine maintenance and repair cycle, the plant control systems will be replaced with upgraded components, which will

include all existing hardware in the field cabinets and the control room, due primarily to the age of the existing equipment and the inability to obtain both parts and support for the older equipment. The replaced hardware will retain all the existing original logic and set points for the preservation of the current plant operation(s), including all balance of plant and gas turbine operations. There will be no changes to performance or facility emissions based on the replaced hardware.

- Turbine upgrade--The A+ upgrade is an optional, logic-based (software) update, which has been engineered to modify certain operational parameters of the gas turbine to increase performance. This A+ upgrade logic portion will not be installed during this maintenance cycle and is not associated with the plant control system replacement. Once approval of the revised AQMD air permit has been obtained, the A+ upgraded software will be installed. This software change can only be installed by Siemens engineers as the logic system is locked. The installation will require the shutdown and re-programming of the gas turbines primary fuel and emissions systems. Additionally, the control system screens will visually indicate that this upgrade logic is "disabled" until it has been approved and implemented.

- **<u>Conditions A99.3, A99.4, and A99.5</u>**

  Note: For Section D (Permits to Operate), condition A99.3, A99.4, and A99.5 will remain unchanged. For new Section H (Permits to Construct), these conditions will become new conditions A99.6, A99.7, and A99.8, respectively and incorporate the updates and revisions resulting from the turbine upgrade project.

  Conditions A99.3, A99.4, and A99.5 will be revised to add that the respective BACT limits shall not apply to commissioning.

- **<u>Condition E193.2</u>**

  New condition E193.2 will limit the turbine upgrade commissioning emissions when steady state BACT is not achievable by limiting the total commissioning hours and hours without control. Bicent Response Letter, 5/17/18, item 7.a.ii.aa. indicates the total commissioning hours are estimated to be 57 hours per turbine. Variance condition no. 4 had stated: Petitioner shall limit the total runtime hours for each combustion turbine during its respective commissioning period of eight (8) calendar days to 56.25 hours. This is supported by Petitioner's Exhibit 1, *Table 1 Malburg Commissioning Schedule*. Bicent Response Letter, item 7.a.ii.bb. states the commissioning hours without controls are estimated to be 32.5 hours per turbine. Petitioner's Exhibit 1, *Table 1* confirms the total runtime plus startup/shutdown hours for days 1 – 6 equal 32.5 hours. Thus condition E193.2 will limit total commissioning hours to 56.25 hours per turbine, and commissioning hours without control to 32.5

hours per turbine. Pursuant to current permitting practice, condition E193.2 will not limit the commissioning to a specific number of days.

Further, the condition will require the certified NOx and CO CEMS to be fully calibrated and operational to measure the NOx and CO emissions during the commissioning.

- **Condition A63.3 Commissioning Factors**

  Note: For Section D (Permits to Operate), condition A63.3 will remain unchanged. For new Section H (Permits to Construct), condition A63.3 will become new condition A63.4 and incorporate the updates and revisions resulting from the turbine upgrade project.

  Condition A63.3 will be revised to add commissioning emission factors for PM_{10}, VOC, and SOx. Bicent Response Letter, 5/17/18, item 7.a.ii.cc confirmed the emissions factors for PM_{10}, VOC, and SOx are the same as was shown for the variance on Petitioner's Exhibit 2, p. 2.

  PM_{10}—For the variance, the EF was 7.397 lb/mmscf, the same as the normal operation emission factor in condition A63.3 at that time. For the turbine upgrade project, the normal operation emission factor will be reduced from 7.397 lb/mmscf to 6.014 lb/mmscf. As discussed below, the emission rate will decrease from 3.89 lb/hr (FDOC) to 2.407 lb/hr (Siemens Table 1), subject to source testing after the turbine upgrade. Thus the commissioning emission factor after turbine upgrade will also be reduced to 6.014 lb/mmscf.

  VOC—For the variance, the uncontrolled EF was 22.6 lb/mmscf. P. 87 of the FDOC indicates uncontrolled VOC is 3.6 ppm and 4.87 lb/mmscf (Scenario S13) during normal operation. P. 87 of the FDOC converts the 3.6 ppm to 2.56 lb/hr.

  In an e-mail, dated 4/2/18, Consultant Gregory Darvin stated that Bicent has decided to be more conservative during the full speed no load tests for the variance. The fuel flow should be 115,000 scfh or 0.115 mmscf/hr rather than the initially proposed 430,000 scfh. This updated the emission factor to the following:

  VOC (lb/mmscf) = 2.56 lb/hr / .115 mmscf/hr = 22.26 lb/mmscf

  The emission factor will be the same for the commissioning after turbine upgrade.

SOx—For the variance, the uncontrolled emission factor was 0.6 lb/mmscf based on FDOC, p. 22. The emission factor will be the same for the commissioning after turbine upgrade.

In addition, condition A63.3 will be revised to add that, for a month during which both commissioning and normal operation take place, the monthly emissions shall be the sum of the commissioning emissions and the normal operation emissions.

- **Maximum Commissioning Emissions**

Petitioner's Exhibit 1, *Table 2 Total Commissioning Emissions, Lbs/Period Per Turbine* shows the total CO emissions is 2842.1 lb, and the total VOC emissions is 127.2 lb. As the condition A63.3 monthly emission limits will limit both commissioning emissions and normal operation emissions, the total CO and VOC commissioning will not be limited by permit condition, pursuant to current permitting practice.

To be conservative, the total CO and VOC emissions are assumed to be emitted in a 30-day period for the calculation of the 30-day averages for commissioning. For each turbine:

CO: 2842.1 lb/30 days = 94.74 lb/day per turbine
VOC: 127.2 lb/30 days = 4.24 lb/day per turbine

Table 11-- Commissioning Emissions (A/N 598922 & 598923-Turbine Upgrade)

	Initial Commissioning (FDOC)		***Commissioning after Turbine Upgrade***
Pollutant	**Turbine 1 30-day Avg, lb/day**	**Turbine 2 30-day Avg, lb/day**	***Turbines 1 and 2 30-day Avg., lb/day per Turbine***
CO	117	137	***94.74***
VOC	59	49	***4.24***

As shown in the table above, the maximum monthly emissions for CO and VOC for the initial commissioning (FDOC) are higher than the maximum monthly emissions for the commissioning after turbine upgrade. Therefore, as discussed below, the 30-day averages and maximum monthly emissions for CO and VOC will continue to be based on the maximum monthly emissions for the initial commissioning (FDOC) and will not need to be increased for the turbine upgrade project.

2) Normal Operating Emissions

The normal operating emissions continue to be calculated using two different methodologies: *a)* AQMD Standard Procedure-Maximum Monthly Emissions, and *b)* Applicant Analysis for Offset Requirements for PM_{10} only.

a) AQMD Standard Procedure—Maximum Monthly Emissions

Case S13 (100% load at 38 °F ambient, duct burner on) provides the highest hourly emissions for each pollutant. The hourly fuel usage, calculated from the data in Siemens Table 1, is 0.563 mmscf/hr. [(491.76 MMBtu/hr (HHV) (turbine) + 81.2 MMBtu/hr (HHV) (duct burner)) x mmscf/1018 MMBtu = 0.563 mmscf/hr.]

As the hourly fuel usage for S13 will increase from 0.526 mmscf/hr for the FDOC to 0.563 mmscf/hr for the turbine upgrade, the hourly emissions rates are expected to increase approximately proportionately. As discussed below, Siemens Table 1 show that the NOx, CO, VOC, and SOx emission rates increase approximately proportionately, but not the PM_{10} emission rate.

Normal Operating Hourly Emissions Rates

NOx: The emission rate is proposed to increase from 4.08 lb/hr (FDOC) to 4.158 lb/hr (Siemens Table 1).

CO: The emission rate is proposed to increase from 2.48 lb/hr (FDOC) to 2.529 lb/hr (Siemens Table 1).

VOC: The emission rate is proposed to increase from 0.85 lb/hr (FDOC) to 0.869 lb/hr (Siemens Table 1).

SO_X: The emission rate is proposed to increase from 0.15 lb/hr (FDOC) to 0.160 lb/hr (Siemens Table 1).

PM_{10}: The emission rate is proposed to decrease from 3.89 lb/hr (FDOC) to 2.407 lb/hr (Siemens Table 1). As discussed below, the SCAQMD will accept a reduction to 3.386 lb/hr.

PM_{10} Emission Rate Prior to Turbine Upgrade (FDOC)

On p. 26 of the FDOC, *Table 11--Maximum Controlled Emissions* shows the maximum PM_{10} emission rate is 3.89 lb/hr for 1 turbine with duct burner based on Scenario S13 (100% load at 38 ºF). P. 87 of the FDOC indicates this PM_{10} factor is based on 0.0066 lb/mmbtu from AP-42.

For the turbine upgrade project, AP-42 was reviewed to determine whether the PM_{10} emission factor had been revised since the FDOC was issued. On p. 3.1-11 of AP-42, Fifth Edition, Chapter 3.1, *Table 3.1-2a. Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines* continues to show that, for natural gas-fired turbines, PM (total) is 6.0 E-03 lb/MMBtu, which converts to 3.53 lb/hr PM_{10} in the turbine exhaust.

P. 87 of the FDOC explains that the PM_{10} emission rate of 3.89 lb/hr includes the additional conversion of SOx to PM_{10}. A 53% molar conversion of SO_2 in the turbine exhaust was assumed to oxidize to SO_3 in the CO catalyst and SCR. The SO_3 reacts with ammonia in the SCR to form ammonium sulfate particulates. Therefore, total PM_{10} is comprised of the PM_{10} in the turbine exhaust and the ammonium sulfate particulates for a total of 3.89 lb/hr PM_{10}.

PM_{10} Emission Rate Subsequent to Turbine Upgrade (A/N 598922 & 598923)
The Application initially proposed to decrease the emission rate from 3.89 lb/hr (FDOC) to 2.407 lb/hr (Siemens Table 1). Siemens Table 1 shows the "Total PM10 with 53% conversion of SOx to PM10" is 2.407 lb/hr for Case S13 (100% load at 38 ºF). In *Attachment 3* of the Application, *Table 1—Maximum Hourly, Daily, and Annual Emissions Calculations, Case #: Max Ops Scenario* bases the maximum emissions calculations for PM_{10} on 2.41 lb/hr PM_{10}.

SCAQMD AI Letter, 5/1/18, item 4.a.i.aa. and 4.a.i.bb. requested that Siemens provide the basis of and a guarantee for the proposed 2.407 lb/hr PM_{10} for Case S13.

Bicent Response Letter, 5/17/18, item 4.a.i.aa. and 4.a.i.bb indicated that Siemens has been forwarded the SCAQMD's request for the basis of and the guarantee for the PM_{10} emission rate. As a Siemens guarantee was not expected for the 2.407 lb/hr (and was never provided), the applicant requested a PM_{10} rate of 3.386 lb/hr instead of the originally requested 2.407 lb/hr.

Note: The proposed 3.386 lb/hr PM_{10} appears to have been back calculated to allow the turbines to operate 720 hr/month (24 hr x 30 days) while maintaining the current condition A63.3 limit of 4876 lb/month PM_{10} for the two turbines combined.

The following summarizes the additional reasons provided by Bicent to support the use of the lower rate of 3.386 lb/hr.

- Source Testing Validity
  SCAQMD AI Letter, 5/1/18, item 4.a.ii. stated: On p. 1-26 of the Application, *Table 13—Summary of Source Test Results for 2014 and 2017 (Required Triennial Tests)* shows the measured PM_{10} emission rate for Turbine 1 with Duct Burner was 0.55 lb/hr in 2014 and 0.88 lb/hr in 2017. For Turbine 2 with Duct Burner, the measured PM_{10} emission rate was 0.62 lb/hr in 2014 and 0.57 lb/hr in 2017. Although these source tests results are sufficient to demonstrate that the PM_{10} emission rate does not exceed the permitted 3.89 lb/hr, as required by condition D29.2, they will not be

sufficient to support the proposed decrease in the maximum PM_{10} emission rate from 3.89 lb/hr to 2.407 lb/hr for the turbine upgrade modification.

Bicent Response Letter, 5/17/18, 4.a.ii.aa and 4.a.ii.bb. provided a summary of a personal communication with Matt McCune, Montrose Air Quality Services, LLC, on 5/4/18. Montrose was the source test firm that performed the source tests in 2014 and 2017. Mr. McCune indicated the source tests had used SCAQMD Method 5.1 which measures total particulate. The current SCAQMD-approved source test method for PM_{10} is EPA Method 201A and SCAQMD Method 5.1. Mr. McCune indicated that he expects that the numbers that Bicent is getting from the total PM tests are "a very good representation of the PM10 emissions as well. If anything, they would over-report PM10 emissions." The response also indicated that the sampling period had met the 4 hours currently required by the SCAQMD. The source test method, sampling period, and source test company had not been provided in the Application.

In addition, the letter provided a table summarizing source test data from similarly sized turbines, both combined cycle and simple cycle utilizing the GE LM6000 turbine and the Alstom GTX 100 along with the test years, test methods and system ratings. All tests were for a minimum of four hours. Some of these turbines are non-identical models with non-identical ratings and are located in different geographic locations.

The most relevant data provided in the table were the 2011 source test results for the Malburg turbines, which had not been provided in the Application. In 2011, the measured PM_{10} emission rate was 0.54 lb/hr for Turbine 1 and 0.21 lb/hr for Turbine 2 with Duct Burner.

In a conference call with Bicent representatives on 6/14/18, SCAQMD staff requested additional source test data on Roseville Energy's source test results, using test methods EPA 201A/202, for the Alstom GTX 100 Units 1 and 2. In addition, SCAQMD staff requested additional information on Redding Electric Utility's source test results, based on test method EPA 5 (subsequently corrected by Shasta County AQMD to be CARB Method 5, front and back half), for an Alstom GTX 100 turbine. Roseville and Redding were the only facilities with Alstom GTX 100 turbines.

In a response e-mail dated 6/19/18, Consultant Gregory Darvin forwarded the source test report results pages for the Roseville Energy Park emission compliance tests, which confirmed the source test results in the table provided in Bicent Response Letter, 5/17/18. The facility is under the

jurisdiction of the Placer County APCD. The source test results for 2008 – 2016 (no tests for 2011) for the two turbines with duct burner firing ranged from 0.31 lb/hr to 1.15 lb/hr PM_{10}.

In addition, the response e-mail forwarded an e-mail correspondence with the Shasta County Air Quality Management District regarding the Redding Electric Utility. The PM_{10} was tested using CARB Method 5, front and back half, on Unit 5. The source test results were 1.7 lb/hr for the 2/8/18 test, 0.531 lb/hr for the 2/25– 2/26/08 test, and 2.7 lb/hr for the 12/4/07 source test. The 2/8/18 source test was the initial source test for the turbine upgrade project.

These results for the Roseville Energy Park and the Redding Energy Utility provide corroborating information that the MGS turbines should be able to meet the proposed PM_{10} emission rate of 3.386 lb/hr.

- HEPA Filters
  Bicent Response Letter, 5/17/18, item 4.a.ii.aa and 4.a.ii.bb indicated that the facility installed HEPA filtration on each of the turbine air inlets in order to eliminate compressor blade fouling from particulate matter. The HEPA filtration is designed to reduce up to 99.5% of the ambient particulate matter greater than 0.1 microns.

- Siemens E-mail on Basis of PM_{10} Emission Rate of 2.407 lb/hr
  Further, in an e-mail dated 8/1/18, Gregory Darvin forwarded an e-mail, dated 6/15/18, from Brennan Smartis, Siemens project manager, stating that Siemens met with Finspång engineering and they elaborated on the PM numbers as follows:

  - PM values were derived from actual measurements taken from other SGT-800 units.
  - The measurements were taken by a third-party during testing to verify emissions guarantees.
  - The PM values include both front-half and back-half values (filterable and condensable).
  - Variations between rating, location, and ambient conditions was shown to not impact the values.
  - The values assume clean air into the GT [gas turbine].

- SCAQMD Determination
  The SCAQMD will accept the proposed PM_{10} emission rate of 3.386 lb/hr based on:

(1) the explanation provided by Matt McCune, Montrose Air Quality Services, LLC, regarding the source test method, including the sampling time of 4 hours, for the prior source tests in 2014 and 2017,
(2) the ambient particulate matter concentration was reduced by the HEPA filters on the turbine air inlets thereby lowering its contribution to the exhaust PM_{10}, and
(3) the Siemens e-mail providing the basis of the 2.407 lb/hr.

Further, condition D29.2 will be revised to reset the triennial source testing requirement for PM_{10}, VOC, and SOx to require an initial source test within 180 days after startup of the turbine upgrade modification. Based on the explanations provided by the Siemens e-mail, dated 6/15/18, an additional interim source test for PM_{10} will not be required 18 months after the initial source test. The next source test for PM_{10}, SOx, and VOC will be required three years after the initial source test.

Further, condition D29.3 will be revised to reset the annual source testing requirement for NH3 to require an initial source test within 180 days after startup of the turbine upgrade modification. The next source test for NH3 will be required annually after the initial source test.

Note: For Section D (Permits to Operate), conditions D29.2 and D29.3 will remain unchanged. For new Section H (Permits to Construct), these conditions will become new conditions D29.4 and D29.5 and incorporate the updates and revisions resulting from the turbine upgrade project.

Startup/Shutdown Limits

P. 1-24 of the Application indicates the applicant is not proposing any changes to the startup or shutdown time limits or emissions for NOx, CO, and VOC in conditions A99.3, A99.4, and A99.5 for the turbine upgrade.

Operating Schedule

Bicent Response Letter, 5/17/18 and 10/20/18, provided confirmation that Bicent is proposing to increase the operating schedule from 645.8 hr/month to 720 hr/month (30 days x 24 hr/day) with an associated increase in the monthly fuel usage limit.

Emissions Calculations

The following emissions calculations are performed pursuant to the standard procedure to determine the monthly maximum emissions for continuously operating equipment. The emissions calculations are performed the same as for A/N 517249 & 517250— Startup and Shutdown Revisions above.

Operating Schedule: 52 wk/yr, 7 days/wk, 24 hr/day

The operating schedule is proposed to increase from 645.8 hr/month (330 ft^3/month x hr/0.511 mmscf) to 720 hr/month.

Normal hrs of operation = 720 hrs – [five cold start (2 hrs) + 5 warm startups (1.5 hrs each) + 10 shutdowns (0.5 hr each)] = 697.5 hrs

NOx

NOx emissions calculations are provided here for informational purposes. The number of RTCs required is calculated under the Rule 2005 analysis below.

Maximum monthly emissions = (122.8 lb/cold start)(5 cold starts) + (51.3 lb/warm startup)(5 warm startups) + (4.5 lb/shutdown) (10 shutdowns) + (4.158 lb/hr normal operation, Siemens Table 1)(697.5 hr) = 3815.71 lb/month

30 DA = 3815.71 lb/30 days = 127.19 lb/day → 127 lb/day

CO

Maximum monthly emissions = (204.8 lb/cold start)(5 cold starts) + (59.9 lb/warm start)(5 warm starts) + (10.8 lb/shutdown) (10 shutdowns) + (2.529 lb/hr normal operation, Siemens Table 1)(697.5 hr) = 3195.48 lb/month

30 DA = 3195.48 lb/30 days = 106.52 lb/day → 107 lb/day

PM_{10}

The emissions per cold start, warm start and shutdown will decrease proportionately with the decrease from 3.89 lb/hr to 3.386 lb/hr. The monthly PM_{10} emissions will be calculated by multiplying the emission rate by 720 hrs.

Maximum monthly emissions = (3.386 lb/hr)(720 hr/month) = 2437.92 lb/month

The 30-day average for the pre-modification emissions calculations for A/N 517249 & 517250, will be revised as follows:

30 DA = ~~2762.58~~ 2437.92 lb/30 days = ~~92.09~~ 81.26 lb/day → ~~92~~ 81 lb/day

Note: Existing condition A63.3 already limits the monthly emissions for both turbines combined to 4876 lbs.

VOC
Maximum monthly emissions = (1.75 lb/cold start)(5 cold starts) + (1.55 lb/warm start)(5 warm starts) + (0.71 lb/shutdown) (10 shutdowns) + (0.869 lb/hr normal operation, Siemens Table 1)(697.5 hr) = 629.73 lb/month

30 DA = 629.73 lb/30 days = 20.99 lb/day → 21 lb/day

SOx
Maximum monthly emissions = (0.2 lb/cold start)(5 cold starts) + (0.16 lb/warm start)(5 warm starts) + (0.03 lb/shutdown) (10 shutdowns) + (0.160 lb/hr normal operation, Siemens Table 1)(697.5 hr) = 113.70 lb/month

30 DA = 113.70 lb/30 days = 3.79 lb/day → 4 lb/day

Note: Existing condition A63.3 limits the monthly emissions for both turbines combined to 214 lbs. The limit will be increased to 227 lbs (2 turbines x 113.70 lb/month per turbine).

b) Applicant Analysis for Offset Requirements (Condition C1.9)

This applicant analysis for offset requirements is applicable only to PM_{10} emissions.

For the FDOC, the *AQMD Standard Procedure—Maximum Monthly Emissions* methodology, based on a normal operating rate of 3.89 lb/hr PM_{10}, arrived at 2784 lb/month per turbine and a 30-day average of 93 lb/day, with a fuel usage of 376 mmscf/month per turbine. If the applicant had provided the necessary offset credits, condition A63.3 would have limited PM_{10} emissions to 5568 lb/month for two turbines (2 turbines times 2784 lb/month per turbine). However, the applicant proposed the use of the *Applicant Analysis for Offset Requirements* methodology to arrive at 2438 lb/month per turbine and a 30-day average of 81 lb/day. The SCAQMD accepted the applicant's proposal for PM_{10} emissions only and revised draft condition A63.3 to reduce the monthly limit for PM_{10} from 5568 lb/month to 4876 lb/month for two turbines (2 turbines x 2438 lb/month per turbine). For 5568 lb/month for two turbines, the fuel usage would have been 376 mmscf/month per turbine. Thus the SCAQMD also added condition C1.4 to limit the fuel usage to 330 MM cubic feet in any calendar month per turbine.

For A/N 598922 & 598923--Turbine Upgrade, based on the decrease in the PM_{10} emission rate from 3.89 lb/hr to 3.386 lb/hr and an increase in the operating schedule from 645.8 hr/month to 720 hr/month, the *AQMD Standard Procedure—Maximum Monthly Emissions* methodology arrived at 2438 lb/month per turbine or 4876 lb/month

per two turbines, and a 30-day average of 81 lb/day per turbine. Therefore, there will be no change to existing condition A63.3 which already limits the PM_{10} emissions for two turbines to 4876 lbs in any month (2 times 2438 lb/month-turbine).

Existing condition C1.4 limits the fuel usage to 330 MM cubic ft in any one calendar month per turbine to ensure that the PM_{10} emissions shall not exceed 2438 lb/month per turbine based on a PM_{10} emission rate of 3.89 lb/hr, or 7.397 lb/mmscf. The reduction of the PM_{10} emission rate to 3.386 lb/hr, or 6.014 lb/mmscf, will increase the fuel limit to 405 cfm.

(2438 lb/month per turbine) (mmscf / 6.014 lb) = 405.39 cfm

The imposition of condition C1.4 for the PDOC was included for clarification but was not necessary because the condition A63.3 limits and emission factors determine the allowed fuel usage. Since the fuel limit condition is currently on the facility permit, it will be revised to increase the fuel usage from 330 mmcf to 405 mmcf. However, a condition limiting fuel usage for turbines is typically not included on turbine permits.

Note: For Section D (Permits to Operate), condition C1.4 will remain unchanged. For new Section H (Permits to Construct), condition C1.4 will become new condition C1.6 and incorporate the updates and revisions resulting from the turbine upgrade project.

3) Bases for 30-Day Averages

The table below is the same as *Table 9 – Basis for 30-Day Averages (A/N 517249 & 517250-Startup & Shutdown Revisions)* above, except as noted. The 30-day averages will **not** change as a result of the turbine upgrade project, including the emissions rate changes and increase in operating schedule, except for NOx which is provided for informational purposes only.

Table 12 - Basis for 30-Day Averages (A/N 598922 & 598923-Turbine Upgrade)

Pollutant	Turbine 1 30-day Avg, lb/day	Turbine 2 30-day Avg, lb/day	Bases for 30-day Averages
NOx	~~99 (FDOC) 125 (SU &SD)~~ **127 (turbine upgrade)**	~~99 (FDOC) 125 (SU & SD)~~ **127 (turbine upgrade)**	Normal operating emissions per *Standard Procedure for Calculating Maximum Monthly Emissions* (Case S13)—Provided for informational purposes as this is a RECLAIM facility. Note: Maximum normal operating month emissions higher than **FDOC** commissioning month emissions of 67 lb/day for Turbine 1 and 53 lb/day for Turbine 2.
CO	117	137	**FDOC** Commissioning period, 2nd month Note: **FDOC** commissioning month emissions higher than maximum normal operating month emissions of ~~105~~ **107** lb/day.
PM_{10}	81	81	Normal operating emissions pursuant to *Applicant Analysis for Offset Requirements* Note: **Based on the decrease in the PM_{10} emission rate from 3.89 lb/hr to 3.386 lb/hr and an increase in the operating schedule from 645.8 hr/month to 720 hr/month, the *SCAQMD Standard Procedure—Maximum Monthly Emissions* methodology also arrived at 2438 lb/month per turbine or 4876 lb/month per two turbines, and a 30-day average of 81 lb/day per turbine.**
VOC	59	49	**FDOC** Commissioning period, 1st month Note: **FDOC** Commissioning month emissions higher than maximum normal operating month emissions of 21 lb/day.
SOx	4	4	*Normal Operating Emissions Pursuant to SCAQMD Standard Procedure* for calculating maximum monthly emissions (Case S13) Note: Maximum normal operating month emissions higher than **FDOC** commissioning emissions of 1 lb/day.

4) Condition A63.3 Monthly Limits

Note: As discussed above, for Section D (Permits to Operate), condition A63.3 will remain unchanged. For new Section H (Permits to Construct), condition A63.3

will become new condition A63.4 and incorporate the updates and revisions resulting from the turbine upgrade project.

Same as A/N 394164 & 394165--FDOC, except the monthly limit for SOx will be increased from 214 lbs/month to 227 lbs/month per two turbines due to the increase in monthly operating hours from 645.8 hr/month (330 ft^3/month x hr/0.511 mmscf) to 720 hr/month.

5) Condition A63.3 Emission Factors

As determined in the FDOC, the current condition A63.3 emission factors, calculated as hourly emission rate divided by hourly gas usage, were based on Scenario S15 (100% load, 65 ºF ambient). The selection of Scenario S15 as the basis for the emission factors, but the selection of S13 for the maximum emissions month calculations, was not discussed in the FDOC.

As the current practice is to base both the maximum monthly limits and associated emission factors on the highest emission rates, the condition A63.3 emission factors for VOC, SOx, and PM_{10} post turbine upgrade will be derived below based on Case S13 (Siemens Table 1). In actuality, the emission factor based on Case S13 is almost the same as the emission factor based on Case S15 because the emission rate is proportional to the fuel usage.

i. VOC Emission Factor

The hourly fuel usage, calculated from data provided in Siemens Table 1, is 0.563 mmscf. [(491.76 MMBtu/hr (HHV) (turbine) + 81.2 MMBtu/hr (HHV) (duct burner)) x mmscf/1018 MMBtu = 0.563 mmscf/hr.]

0.869 lb/hr ÷ 0.563 mmscfh = 1.54 lbs/mmscf

The EF will be revised from 1.63 lbs/mmscf to 1.54 lbs/mmscf.

ii. SOx Emission Factor

0.16 lb/hr ÷ 0.563 mmscfh = 0.28 lbs/mmscf

The EF is 0.28 lbs/mmscf and will remain 0.28 lbs/mmscf.

iii. PM_{10} Emission Factor

3.386 lb/hr ÷ 0.563 mmscfh = 6.014 lbs/mmscf

The EF will be revised from 7.397 lbs/mmscf to 6.014 lbs/mmscf.

6) New Source Review Database Entries - R1 and R2 Calculations

For A/N 394164 & 394165—FDOC, and A/N 517249 & 517250—Startup and Shutdown Revisions, the R1 and R2 entries were the uncontrolled and controlled normal operating emissions rates. The startup and shutdown emissions were not taken into account. However, the 30-day averages in NSR were **not** the 30-day averages calculated by the NSR Tracking System from the R2 emission rate. The engineer manually input the 30-day averages, which are based on the higher of the emissions for a commissioning month or a normal operating month (comprised of normal operating emissions, startups, and shutdown), using the override function.

For A/N 59822 & 598923, R1 and R2 have changed as a result of the turbine upgrade. Instead of updating R1 and R2, R1 and R2 will be back calculated from the 30-day averages from *Table 12 - Basis for 30-Day Averages (A/N 598922 & 598923-Turbine Upgrade)* above for the purpose of input into the internal NSR Data Summary Sheet only. The uncontrolled and controlled concentrations are from the R1 and R2 Calculations for A/N 394164 & 394165 above.

Operating Schedule: 52 wks/yr, 7 days/wk, 24 hr/day (annualized schedule)

NOx

R2 = (127 lb/day)(day/24 hr) = 5.29 lb/hr

R1 = (5.29 lb/hr)(22 ppm uncontrolled/2 ppm controlled) = 58.19 lb/hr

30-DA = 127 lb/day

[Normal operating emissions, *Standard Procedure For Calculating Maximum Monthly Emissions* (Scenario S13)]

CO

Turbine 1: R2 = R1 = (117 lb/day)(day/24 hr) = 4.88 lb/hr
30-DA = 117 lb/day

Turbine 2: R2 = R1 = (137 lb/day)(day/24 hr) = 5.71 lb/hr
30-DA = 137 lb/day

Assume R2 = R1 because the 30-day average emissions are based on the maximum commissioning month.

[Commissioning period, 2nd month]

PM_{10}

R2 = R1 = (81 lb/day)(day/24 hr) = 3.38 lb/hr

30-DA = 81 lb/day

[Normal operating emissions, *Standard Procedure For Calculating Maximum Monthly Emissions* (Scenario S13) and *Applicant Analysis For Offset Requirements (Scenario No. 1)*]

ROG
Turbine 1: R2 = R1 = (59 lb/day)(day/24 hr) = 2.46 lb/hr
30-DA = 59 lb/day

Turbine 2: R2 = R1 = (49 lb/day)(day/24 hr) = 2.04 lb/hr
30-DA = 49 lb/day

Assume R2 = R1 because the 30-day average emissions are based on the maximum commissioning month.

[Commissioning period, 1st month]

SOx
R2 = R1 = (4 lb/day)(day/24 hr) = 0.17 lb/hr

30-DA = 4 lb/day

[Normal operating emissions, *Standard Procedure for Calculating Maximum Monthly Emissions* (Scenario S13)]

◆◆

GREENHOUSE GASES (GHG)--TURBINES

A. Initial Emissions: A/N 394164 & 394165—FDOC, and Pre-Modification Emissions: A/N 517249 & 517250—Startup and Shutdown Revisions

Greenhouse gas emissions were not required to be calculated for these applications. The emissions are the same as calculated for post-modification below because GHG emissions are typically conservatively based on 8760 hr/yr instead of actual operating schedule.

B. Post-Modification Emissions: A/N 598922 & 598923--Turbine Upgrade

- ***Turbine Combustion: CO_2, CH_4, N_2O***
  Combustion of natural gas in the turbines and duct burners result in emissions of CO_2, CH_4, and N_2O.

As discussed below for the toxic pollutants calculation, the annual gas usage is comprised of normal operation with duct burner firing (Case S15, 100% load at 65 ºF) and startup/shutdown without duct burner firing (Case S11, 100% load at 65 ºF without duct firing). The reason for the distinction is that duct firing does not occur during startup/shutdown periods.

Normal Operating Hrs = 8760 hr/yr – [(30 cold starts)(2 hr/cold start) + (26 non-cold starts)(1.5 hr non-cold start) + (56 shutdowns)(0.5 hr)]
= 8760 hr/yr – 127 hr/yr SU/SD = 8633 hr/yr

Annual fuel use, lb/yr = [(average hourly heat input rate of 474.61 MMBtu/hr for turbine + 81 MMBtu/hr for duct burner (HHV)(Case S15) (8633 hr/yr)] + [474.61 MMBtu/hr for turbine (HHV)(Case S11)(127 hr/yr for SU/SD)])
= 4,856,856.6 MMBtu/yr

Emission factors for CO_2, CH_4, and N_2O are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised March 9, 2018. (See table at https://www.epa.gov/sites/production/files/2018-03/documents/emission-factors_mar_2018_0.pdf)

For each turbine:

CO_2: 53.06 kg CO_2/MMBtu
CH_4 : 1 g CH_4/MMBtu
N_2O: 0.10 g N_2O/MMBtu

CO_2 = (4,856,856.6 MMBtu/yr)(53.06 kg/MMBtu)(2.2046 lb/kg)
= 568,136,026.8 lb/yr = 284,068.01 tpy

CH_4 = (4,856,856.6 MMBtu/yr)(1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 10,709.37 lb/yr = 5.35 tpy

N_2O = (4,856,856.6 MMBtu/yr)(0.1 g/MMBtu)(2.205 x 10^{-3} lb/g)
= 1070.94 lb/yr = 0.54 tpy

Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as amended by 79 FR 73779, 12/11/14: *(1)* CH_4 is equivalent to 25 times the global warming potential of CO_2, and *(2)* N_2O is equivalent to 298 times of CO_2. (See table at https://www.ecfr.gov/cgi-bin/text-idx?SID=9df2d28baf52a7d89fffa94ef843b1b0&mc=true&node=ap40.23.98_19.1&rgn=div9)

CO_2e, tpy = (568,136,026.8 lb/yr CO_2)(1 lb CO_2e/lb CO2) + (10,709.37 lb/yr CH_4) (25 lb CO2e/lb CH_4) + (1070.94 lb/yr N_2O)(298 lb CO_2e/lb N_2O)
= 568,722,091.2 lb/yr = 284,361.45 tpy = 23,696.79 tons/month

- ***Circuit Breakers: SF6***
  Bicent Response Letter, 10/20/18, item 13.b. stated there are no circuit breakers that utilize SF6 or any other GHG compounds.

◆◆

***TOXIC POLLUTANTS*--TURBINES**

A. Initial Emissions: A/N 394164 & 394165—FDOC, and Pre-Modification Emissions: A/N 517249 & 517250—Startup and Shutdown Revisions

P. 58 of the FDOC provides the hazardous air pollutants calculations based on emission factors from the CARB air toxic database (2001). The emission factors and control efficiencies are updated below for the turbine upgrade project.

B. Post-Modification Emissions: A/N 598922 & 598923--Turbine Upgrade

The Application provided toxic air contaminant and hazardous air pollutant emissions calculations in *Attachment 3, Table 6—Calculation of Hazardous and Toxic Pollutant Emissions from Combustion Turbines* for the Rule 1401 health risk assessment (HRA). The emissions, based on SCAQMD-approved emission factors and control efficiencies from AP-42, are shown in the table below.

Bicent Response Letter, 5/17/18, item 9.b.i. indicated the annual toxic emissions were incorrectly based on 4774.81 mmscf/yr per turbine and the rate should be 4772.7 mmscf/yr. The letter provided a revised *Attachment 3, Table 6* with the annual emissions based on 4772.7 mmscf/yr, but did not re-run the health risk assessment because it was based on the higher fuel usage of 4774.81 mmscf/yr. Consequently, the *Rule 1401--New Source Review of Toxic Air Contaminants* analysis below is based on toxic emissions based on 4774.81 mmscf/yr. However, the *40 CFR Part 63 Subpart YYYY--NESHAPS for Stationary Combustion Turbines* regulatory analysis below is based on toxic emissions based on 4772.7 mmscf/yr.

Table 13--Toxic Air Contaminants/Hazardous Air Pollutants per Turbine (A/N 598922 & 598923-Turbine Upgrade)

Pollutant	CAS	TAC/HAP	Emission Factor [1]	Emissions per Turbine		
			lb/MMscf	lb/hr	lb/yr	Ton/yr
Ammonia [4]	766417	TAC	5 ppm	3.84	33638.40	
Acetaldehyde [2]	75070	TAC & HAP	0.179168	0.1008	~~855.4932~~ 855.1151	
Acrolein [2]	107028	TAC & HAP	0.003685	0.0021	~~17.5952~~ 17.5874	
Benzene [2]	71432	TAC & HAP	0.003319	0.0019	~~15.8476~~ 15.8406	
1,3-Butadiene	106990	TAC & HAP	0.000438	0.0002	~~2.0914~~ 2.0904	
Ethylbenzene	100414	TAC & HAP	0.032576	0.0183	~~155.5442~~ 155.4755	
Formaldehyde [2]	50000	TAC & HAP	0.366480	0.2063	~~1749.8724~~ 1749.0991	
Hexane **Note**: EF is 0 because AP-42 does not provide an emission factor and CATEF factors are not SCAQMD-approved.	110543	TAC & HAP	0	0	0	
Naphthalene	91203	TAC & HAP	0.001323	0.0007	~~6.3171~~ 6.3143	
PAHS (excluding naphthalene) [3] [(2.2E-06 – 1.3E-06) MMBtu/hr] [1017 Btu/scf] = 0.000915 lb/mmscf	1151	TAC & HAP	0.000916	0.0005	~~4.3737~~ 4.3718	
Propylene [4] **Note**: EF is 0 because AP-42 does not provide an emission factor and CATEF factors are not SCAQMD-approved.	115071	TAC	0	0	0	
Propylene Oxide	75569	TAC & HAP	0.029522	0.0166	~~140.9619~~ 140.8996	
Toluene	108883	TAC & HAP	0.132340	0.0745	~~631.8984~~ 631.6191	
Xylene	1330207	TAC & HAP	0.065152	0.0367	311.0884 310.9510	
Total Annual HAPS Emissions per Turbine					~~3891.0835~~ **3889.3639**	~~1.9455~~ **1.9447**
Total Annual Toxic Air Contaminants Emissions per Turbine					~~37.529.4835~~ **37,527.7639**	~~18.7647~~ **18.7639**

[1] Emission factors based on AP-42, Section 3.1, Final Section, Table 3.1-3--Emission Factors for Hazardous Air Pollutants from Natural Gas-Fired Stationary Gas Turbine (Uncontrolled), April 2000, unless otherwise noted in footnote 2 below. The table provides factors in lb/MMBtu. To convert from lb/MMBtu to lb/MMscf, the factors are multiplied by 1018 Btu/scf.

[2] Acetaldehyde, acrolein, benzene, and formaldehyde emission factors are based on AP-42, Section 3.1, Background Information, Table 3.4-1--Summary of Emission Factors for Natural Gas-Fired Gas Turbines, April 2000, for "High Loads: Greater Than or Equal to 80 Percent." These emission factors include control by CO catalyst. The table provides factors in lb/MMBtu and lb/mmscf based on 1020 Btu/scf.

[3] Carcinogenic PAHs only. Naphthalene is subtracted from the total PAHs and considered separately in the HRA.

[4] Ammonia and propylene are toxic air contaminants for the purpose of Rule 1401, but not federal hazardous air pollutants.

The hourly and annual emissions are calculated as follows:

Compounds other than ammonia

- Hourly Emissions

  Max hourly emissions, lb/hr = [Emission Factor] [maximum hourly heat input rate of 491.76 MMBtu/hr $_{\text{turbine}}$ + 81.2 MMBtu/hr $_{\text{duct burner}}$ (Case S13)] [scf/1018 Btu] = [EF] [0.5628 MMscf/hr]

- Annual Emissions

  Normal operating hrs = 8760 hr/yr – [(30 cold starts)(2 hr/cold start) + (26 non-cold starts)(1.5 hr non-cold start) + (56 shutdowns)(0.5 hr)] = 8760 hr/yr – 127 hr/yr SU/SD] = 8633 hr/yr

  Annual emissions, lb/yr = [Emission Factor] {[average hourly heat input rate of 474.61 MMBtu/hr $_{\text{turbine}}$ + 81.2 MMBtu/hr $_{\text{duct burner}}$ (Case S15)) (8633 hr/yr)] + [474.61 MMBtu/hr $_{\text{turbine}}$ (Case S11)(127 hr/yr for SU/SD)]} (scf/1018 Btu) = [EF][4772.68 MMscf/yr]

  Bicent Response Letter, 5/17/18, item 9.b.i. provided clarification on the derivation of the annual fuel usage of 4774.81 mmscf/yr per turbine in *Attachment 3, Table 6—Calculation of Hazardous and Toxic Pollutant Emissions from Combustion Turbines*. The letter indicates the 4774.81 mmscf/yr was incorrect and the rate should be 4772.7 mmscf/yr per turbine as shown in *Attachment 3 ,Table 3—Malburg Fuel Use Calculations* and *Table 2—Fuel Use Summary-maximum values* on p. 1-6 of the Application.

  The annual gas usage is comprised of normal operation with duct burner firing (Case S15, 100% load at 65 ºF) and startup/shutdown without duct burner firing (Case S11, 100% load at 65 ºF without duct firing). The reason for the distinction is that duct firing does not occur during startup/shutdown periods. (*Table 2* and *Attachment 3, Table 3* incorrectly indicate startup/shutdown without duct burner firing is based on Case S9, instead of the correct Case S11. Also, the duct burner rating is 81 MMBtu/hr for Case S15 for the annual usage. However, 81.2 MMBtu/hr (Case S13) was used because the maximum hourly, daily, and monthly gas usage are based on Case S13.)

Ammonia

- Hourly Emissions

Max hourly emissions, lb/hr = 3.84 lb/hr (Siemens Table 1, Case S13)

- Annual Emissions
  Annual emissions, lb/yr = (3.84 lb/hr)(8760 hr/yr) = 33,638.4 lb/yr

◆◆

3. Cooling Tower (Exempt from Permitting)

The cooling tower PM_{10} emissions are required to be calculated to support Bicent's Petition to revise Condition of Certification AQ-C7 to increase the limit for the PM_{10} emissions for the cooling tower from 6.2 lb/day to 7.3 lb/day. In addition, pursuant to Rule 219(s)(2)(A), the toxic emissions are required to be calculated to confirm the health risk assessment supports the exemption from permitting.

For the turbine upgrade project, these emissions will change because the cooling tower circulating pumps will be run at a slightly higher capacity to handle the increased heat rejection from the turbines after the upgrade.

CRITERIA POLLUTANTS—Cooling Tower

A. Initial Emissions: A/N 394164 & 394165—FDOC

The cooling tower specifications are found on p. 18 of the FDOC, and the cooling tower data and PM_{10} emissions calculations are found on pp. 29-30 of the FDOC.

PM_{10} is released from a cooling tower through "drift,", which is water entrained by and carried with the air as fine droplets. The water droplets evaporate and leave the dissolved solids as PM_{10} emissions.

The FDOC does not discuss the methodology, but EPA AP 42, Fifth Edition, Volume I, Chapter 13: Miscellaneous Sources, 13.4 Wet Cooling Tower, provides on pp. 13.4-3 to 13.4-4 the following methodology:

First, a *conservatively high* PM-10 emission factor can be obtained by (a) multiplying the total liquid drift factor by the total dissolved solids (TDS) fraction in the circulating water and (b) assuming that, once the water evaporates, all remaining solid particles are within the PM-10 size range.

Second, if TDS data for the cooling tower are not available, a source-specific TDS content can be estimated by obtaining the TDS data for the make-up water and multiplying them by the cooling tower cycles of concentration. The cycles of concentration ratio is the ratio of a measured parameter for the cooling tower water (such as conductivity, calcium, chlorides, or phosphate) to that parameter for the make-up

water. This estimated cooling tower TDS can be used to calculate the PM-10 emission factor as above.

The FDOC calculations are based on the second option because the TDS of the circulating water was not available since the cooling tower had not been constructed. The cooling tower is comprised of three cells. For the purposes of modeling, the 3-cell tower is modeled as 3 point sources, with one-third of the total emissions per cell.

The FDOC calculations are as follows:

Operating Schedule	52 wk/yr, 7 days/wk, 24 hr/day
Maximum circulation rate	25,000 gpm
No. of cells	3 cells
Make-up water total dissolved solids (TDS)	1000 mg/l
Drift rate (% of circulation rate)	0.0005%
Cycles of concentrations	4 cycles

Circulation Drift, gal/min = (25,000 gal/min, circulation rate) (0.000005, drift rate)
= 0.13 gal/min

Drift, lbs/day = (0.13 gal/min) (60 min/hr) (24 hr/day) (8.334 lb/gal water)
= 1560 lb/day

Total Dissolved Solids (TDS) in Circulating Water, mg/l or ppm =
(TDS in make-up water (mg/l)) (no. of concentration cycles) =
(1000 mg/l)(4 cycles) = 4000 mg/l = 4000 ppm

PM_{10}, lb/day = (Drift * TDS Concentration in Circulating Water) / 1,000,000
= (1560 lb/day * 4000 ppm) / 1,000,000 = 6.24 lb/day

B. Post-Modification Emissions: A/N 598922 & 598923--Turbine Upgrade

The Application for turbine upgrade provides cooling tower emissions calculations in *Attachment 3, Table 5—Cooling Towers-Wet Surface Condensers.*

For the turbine upgrade project, the two changes to the FDOC emissions calculations are:

1) Maximum circulating rate = pumping rate of recirculation pumps = 26,927.4 gal/min. This is an increase from the 25,000 gal/min in FDOC, p. 29.

Bicent Response Letter, 5/17/18, item 6.b.i. explains the MGS staff based the increased circulation rate from an assumed approximate increase in heat rejection of 8% after adjusting for the needed discharge pressure.

2) Make-up water TDS = ~~1125~~ **1120** mg/l.
This is an increase from the 1000 mg/l in FDOC, p. 29. Bicent Response Letter, 5/17/18, item 6.b.ii. provided the water analysis on which the increased TDS was based. The Positive Lab Service Certificate of Analysis, PLS Report No.: 1604025, Report Date: 04/11/16, shows measured Total Dissolved Solids is 1020 mg/l TDS. Bicent Response Letter, 10/20/18, item 6.b.iii. indicated the 1125 mg/l was in error and should be 1020 mg/l.

The emissions calculations for the FDOC are revised as follows:

Operating Schedule	52 wk/yr, 7 days/wk, 24 hr/day
Maximum circulation rate	~~25,000~~ **26,927.4** gpm
No. of cells	3 cells
Make-up water total dissolved solids (TDS)	~~1000~~ ~~1125~~ **1020** mg/l
Drift rate (% of circulation rate based on design control efficiency of drift eliminators)	0.0005%
Cycles of concentrations	4 cycles (design)

Circulation Drift, gal/min = (~~25,000~~ **26,927.4** gal/min, circulation rate) (0.000005, drift rate) = ~~0.13 (0.125)~~ **0.135** gal/min

Drift, lbs/day = (~~0.13~~ **0.135** gal/min) (60 min/hr) (24 hr/day) (8.334 lb/gal water) = ~~1560~~ **1621.30** lb/day

Total Dissolved Solids (TDS) in Circulating Water, mg/l or ppm =
TDS in make-up water (mg/l) * concentration cycles =
~~1000~~ ~~1125~~ **1020** mg/l * 4 cycles = ~~4000~~ ~~4500~~ **4080** mg/l = ~~4000~~ ~~4500~~ **4080** ppm

PM_{10}, lb/day = [Drift * TDS Concentration in Circulating Water] / 1,000,000 =
[~~1560~~ **1621.30** lb/day * ~~4000~~ ~~4500~~ **4080** ppm] / 1,000,000 = ~~6.24~~ ~~7.30~~ **6.61** lb/day

Note: In the Petition, Bicent requested the CEC to revise Condition of Certification AQ-C7 to increase the limit for the PM_{10} emissions from the cooling tower from 6.2 lb/day to 7.3 lb/day. With the correction in the emissions calculations, the increase will be to 6.6 lb/day.

Hourly emissions = (6.6 lb/day)(day/24 hr) = 0.28 lb/hr
Annual emissions = (6.6 lb/day)(365 day/yr) = 2409 lb/yr = 1.2 tpy

***TOXIC POLLUTANTS*—Cooling Tower**

A. Initial Emissions: A/N 394164 & 394165—FDOC

From p. 30 of the FDOC:
There are only non-volatile toxic air contaminant (TAC) emissions from the cooling tower because there are no volatile toxic emissions in the make-up water.

The emissions calculations below are for the cooling tower, which is comprised of three cells. For the purposes of modeling, the 3-cell tower is modeled as 3 point sources, with one-third of the total emissions per cell.

Concentration of TAC in circulating water = (concentration of TAC in make-up water, mg/l) (no. of concentration cycles)

Emission rate for each TAC, lbs/hr = (concentration of TAC in make-up water, mg/l) (4 concentration cycles) (drift, gpm) (3.785 l/gal) (g/1000 mg) (60 min/hr) (lb/453.6 g)
= (concentration of TAC in make-up water, mg/l) (4 concentration cycles) (0.13 gal/min drift)(5.007 E-4)

B. Post-Modification Emissions: A/N 598922 & 598923--Turbine Upgrade

The Application provides updated toxic pollutant calculations for the cooling tower in *Attachment 3, Table 7—Calculation of Hazardous and Toxic Pollutant Emissions from Cooling Towers.* The footnotes indicate the concentrations of arsenic, beryllium, cadmium, chromium, and lead were input as ½ the minimum detection limit or PQL, and the concentrations of the remaining constituents were from the water analysis data supplied by project applicant on 10/20/17, sample date 10/18/17, Table page 2.

For the purposes of modeling, the 3-cell tower is modeled as 3 point sources, with one-third of the total emissions per cell.

For the turbine upgrade project, the two changes to the FDOC emissions calculations are:

1) Drift rate = 0.135 gal/min.
   This is an increase from the 0.13 gal/min in FDOC, p. 29.

2) Concentration of each TAC in cooling tower water, mg/l.

For the FDOC, the toxic emissions concentrations in the circulating water were estimated by multiplying the toxic emissions concentrations in the make-up water from the lab analysis report by 4 cycles of concentration.

For the turbine upgrade project, the toxic emissions concentration in the circulating water for the cooling tower were directly determined by lab analysis. Bicent Response Letter, 5/17/18, item 6.c. provides a copy of the referenced water analysis for the cooling tower water. The Positive Lab Service Certificate of Analysis, PLS report No. 1710138, for a report date of 10/20/17 and a sample submitted date of 10/18/17 provides the concentrations of arsenic, beryllium, cadmium, chromium, and lead were shown as ND (non-detectable), and the measured concentrations of the copper, nickel, selenium, vanadium, manganese, and silica.

Emission rate for each TAC, lbs/hr = (concentration of TAC in circulating water, mg/l) (drift, gpm) (3.785 l/gal) (g/1000 mg) (60 min/hr) (lb/453.6 g) = (concentration of TAC in circulating water, mg/l) (~~0.13~~ **0.135** gal/min drift)(5.007 E-4)

Annual emissions, lbs/hr = (TAC emissions, lbs/hr) (8760 hr/yr)

Emissions per cell = Total Tower Emissions/3 cells

Table 14 -- Toxic Air Contaminants/Hazardous Air Pollutants for Cooling Tower (A/N 598922 & 598923-Turbine Upgrade)

Toxic Air Contaminant	TAC Concentration in Cooling Tower Water	Emissions per Cell		Total Tower Emissions (3 cells)	
	ppm (equal to mg/l)	lb/hr	lb/yr	lb/hr	lb/yr
Arsenic	0.01	2.24E-07	1.97E-03	6.73E-07	5.90E-03
Beryllium	0.0025	5.61E-08	4.91E-04	1.68E-07	1.47E-03
Cadmium	0.0025	5.61E-08	4.91E-04	1.68E-07	1.47E-03
Chromium	0.005	1.12E-07	9.83E-04	3.37E-07	2.95E-03
Copper [1]	0.031	6.96E-07	6.09E-03	2.09E-06	1.83E-02
Lead	0.005	1.12E-07	9.83E-04	3.37E-07	2.95E-03
Manganese	0.116	2.60E-06	2.28E-02	7.81E-06	6.84E-02
Mercury	0.0005	1.12E-08	9.83E-05	3.37E-08	2.95E-04
Nickel	0.015	3.37E-07	2.95E-03	1.01E-06	8.85E-03
Selenium	0.025	5.61E-07	4.91E-03	1.68E-06	1.47E-02
Silica [2]	106	2.38E-03	2.08E+01	7.14E-03	6.25E+01
Vanadium [1]	0.012	2.69E-07	2.36E-03	8.08E-07	7.08E-03
Total Annual HAP Emissions, lb/yr (TPY)					**62.61 = 0.031TPY**

[1] Copper and vanadium are not federal HAPs.

[2] Silica is a HAP (fine mineral fibers), but not a Rule 1401 toxic air contaminant.

◆◆

4. Internal Combustion Engine, Emergency Fire Pump (D48)

The internal combustion engine is not being revised by this project. However, the facility-wide air dispersion modeling and the facility-wide health risk assessment provided for CEC's CEQA review includes the emergency fire pump. Therefore, the criteria pollutant and toxic pollutant emission rates are provided below for the facility-wide analyses.

Criteria Pollutants

From A/N 482576:

CO: 0.40 g/bhp-hr = 0.153 lb/hr
NOx: 3.9 g/bhp-hr = 1.487 lb/hr
PM_{10}: 0.09 g/bhp-hr = 0.034 lb/hr
VOC: 0.10 g/bhp-hr = 0.038 lb/hr
SOx: 0.003 lb/hr

The SOx emission rate will be updated to 0.0019 lb/hr based on 0.0049 g/bhp-hr for 15 ppmw fuel to reflect the current lower sulfur content in diesel fuel.

Toxic Pollutants

Diesel PM, lb/hr = 0.034 lb/hr, carcinogenic and chronic but not acute.
lb/yr = (0.034 lb/hr)(200 hr/yr) = 6.8 lb/yr → 0.0034 tpy

Greenhouse Gases

Emission factors for CO_2, CH_4, and N_2O are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised March 9, 2018, for fuel type Distillate Fuel Oil No. 2.

CO_2: 10.21 kg CO_2/gallon
CH_4: 0.41 g CH_4/gallon
N_2O: 0.08 g N_2O/gallon

From A/N 438859 file, the specs indicate the fuel rate = 33 liters /hr, or 8.72 gal/hr.

CO_2 = (10.21 kg/gallon)(8.72 gal/hr)(2.2046 lb/kg)(200 hr/yr) = 39,255.64 lb/yr
CH_4 = (0.41 g/gallon)(8.72 gal/hr)(2.205 x 10^{-3} lb/g)(200 hr/yr) = 1.58 lb/yr
N_2O = (0.08 g/gallon)(8.72 gal/hr)(2.205 x 10^{-3} lb/g)(200 hr/yr) = 0.31 lb/yr

CO_2e, tpy = (39,255.64 lb/yr CO_2)(1 lb CO_2e/lb CO2) + (1.58 lb/yr CH_4)
(25 lb CO2e/lb CH_4) + (0.31 lb/yr N_2O)(298 lb CO_2e/lb N_2O)
= 39,387.52 lb/yr = 19.69 tpy

♦♦♦

5. Maximum Facility Annual Emissions

The maximum annual emissions for the facility will be calculated below for the purpose of regulatory analysis in the **Rule Evaluation** section.

A. Pre-Modification: A/N 517249 & 517250—Startup and Shutdown Revisions

The pre-modification maximum annual emissions for the facility are summarized in the table below. The cooling tower is not included because it is exempt from permitting.

Table 15 - Facility Maximum Annual Emissions, Pre-Modification (A/N 517249 & 517250-Startup & Shutdown Revisions)

	Tons/Year						
Equipment	**NOx**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**	**SOx**	**NH_3**	**CO_2e**
Turbine No. 1	20.25	22.90	9.71	14.63	0.64		284,361.45
Turbine No. 2	20.25	22.90	9.71	14.63	0.64		284,361.45
Turbine Circuit Breakers							0
SCR/CO Catalyst for Turbine No. 1						16.60	
SCR/CO Catalyst for Turbine No. 2						16.60	
Ammonia Tank						0	
Fire Pump	0.15	0.015	0.004	0.003	0.0003		19.69
Facility Total	**40.65**	**45.82**	**19.42**	**29.26**	**1.28**	**33.20**	**568,742.59**

The annual emissions for NOx, CO, PM_{10}, VOC, SOx, and NH_3 for the table above are calculated below. The annual greenhouse gas emissions, including CO2e, are included in the emissions calculations above for the turbines and fire pump.

Turbine No. 1, Turbine No. 2

NOx

Conditions I298.1 require 34349 lb of NOx RTCs for Turbine No. 1 and 6143 lb of NOx RTCs for the associated duct burner for a total of 40492 lb/yr. However, the required RTC holdings are not an annual limit because RECLAIM facilities do not have an annual emissions limit for NOx. Therefore, the annual potential to emit will be calculated for NOx for each turbine with duct burner below.

Condition A99.3 provides duration and emissions limits for annual cold starts, non-cold starts, and shutdowns.

8760 hr/yr – (30 cold starts)(2 hr/cold start) – (26 non-cold start)(1.5 hr/non-cold start) – (56 shutdowns)(0.5 hr/shutdown) = 8633 hr normal operation

(30 cold starts)(122.8 lb/cold start) + (26 non-cold starts)(51.3 lb/non-cold start) + (56 shutdowns)(4.5 lb/shutdown) + (8633 hr normal operation)(4.08 lb/hr (S13)] =

40,492.44 lb/yr = 20.25 tpy

CO, PM_{10}, VOC, SOx

The condition A63.3 monthly limits are for both turbines combined. The annual emissions per turbine are equal to the condition A63.3 monthly limits, divided by two turbines, multiplied by 12 months. The condition A63.3 monthly limits are based on the 30-day averages of two turbines combined.

CO: (7633 lb/month/2 turbines)(12 months/yr)(ton/2000 lb) = 22.90 tpy
PM_{10}: (4876 lb/month/2 turbines)(12 months/yr)(ton/2000 lb) = 14.63 tpy
VOC: (3236 lb/month/2 turbines)(12 months/yr)(ton/2000 lb) = 9.71 tpy
SOx: (214 lb/month/2 turbines)(12 months/yr)(ton/2000 lb) = 0.64 tpy

SCR/CO Catalyst for Turbine No. 1, SCR/CO Catalyst for Turbine No. 2

P. 49 of FDOC provided the NH_3 hourly emissions, same as 30-day average.

NH_3: (3.80 lb/hr)(24 hr/day)(7 day/wk)(52 wk/yr)(ton/2000 lb) = 16.60 tpy

Ammonia Tank

FDOC provided the 30 day average as 0 lb/day.

NH_3: 0 lb/hr = 0 lb/day = 0 tons/yr

Fire Pump

A/N 438859 provided the emission rates for the fire pump. At the time, A/N 438859 was issued, the regulatory operating limit was 199 hr/yr for emergency engines. Thereafter, the regulatory limit was increased to 200 hr/yr.

NOx: (1.487 lb/hr)(200 hr/yr)(ton/2000 lb) = 0.15 tpy
CO: (0.153 lb/hr)(200 hr/yr)(ton/2000 lb) = 0.015 tpy
PM_{10}: (0.034 lb/hr)(200 hr/yr)(ton/2000 lb) = 0.003 tpy
VOC: (0.038 lb/hr)(200 hr/yr)(ton/2000 lb) = 0.004 tpy
SOx: (0.003 lb/hr)(200 hr/yr)(ton/2000 lb) = 0.0003 tpy

♦♦

B. Post-Modification: A/N 598922 & 598923--Turbine Upgrade

The post-modification maximum annual emissions for the facility are summarized in the table below, with the emissions calculations for each equipment shown following the table. The changes shown below are to the pre-modification annual emissions and emissions calculations.

Table 16 - Facility Maximum Annual Emissions, Post-Modification (A/N 598922 & 598923—Turbine Upgrade)

	Tons/Year						
Equipment	**NOx**	**CO**	**VOC**	**$PM_{10}/PM_{2.5}$**	**SOx**	**NH_3**	**CO_2e**
Turbine No. 1	~~20.25~~ **20.58**	22.90	9.71	14.63	~~0.64~~ **0.68**		284,361.45
Turbine No. 2	~~20.25~~ **20.58**	22.90	9.71	14.63	~~0.64~~ **0.68**		284,361.45
Turbine Circuit Breakers							0
SCR/CO Catalyst for Turbine No. 1						16.60	
SCR/CO Catalyst for Turbine No. 2						16.60	
Ammonia Tank						0	
Fire Pump	0.15	0.015	0.004	0.003	~~0.0003~~ **0.00019**		19.69
Facility Total	~~**40.65**~~ **41.31**	**45.82**	**19.42**	**29.26**	~~**1.28**~~ **1.36**	**33.20**	**568,742.59**
Changes in Maximum Annual Emissions	**0.66**	**0**	**0**	**0**	**0.08**	**0**	**0**

Turbine No. 1, Turbine No. 2

NOx

Condition A99.3 limits cold start, non-cold start, and shutdown emissions. RECLAIM facility has no annual emissions limit for NOx.

8760 hr – (30 cold starts)(2 hr/cold start) – (26 non-cold start)(1.5 hr/non-cold start) – (56 shutdowns)(0.5 hr/shutdown) = 8633 hr normal operation

(30 cold starts)(122.8 lb/cold start) + (26 non-cold starts)(51.3 lb/non-cold start) + (56 shutdowns)(4.5 lb/shutdown) + (8633 hr normal operation)(4.158 lb/hr (S13)] = 41,165.81 lb/yr = 20.58 tpy

CO, PM_{10}, VOC—As the condition A63.3 monthly limits per two turbines combined will not change, the annual emissions will not change.

SOx—The condition A63.3 monthly limit per two turbines combined will be increased from 214 lb/month to 227 lb/month.

SOx: (~~214~~ **227** lb/month/2 turbines)(12 months/yr)(ton/2000 lb) = ~~0.64~~ **0.68** tpy

SCR/CO Catalyst for Turbine No. 1, SCR/CO Catalyst for Turbine No. 2
As the control equipment will not be modified, the annual emissions will remain the same.

NH_3: (3.80 lb/hr)(24 hr/day)(7 day/wk)(52 wk/yr)(ton/2000 lb) = 16.60 tpy

Ammonia Tank
NH_3: 0 tons/yr

Fire Pump
Emission rates from A/N 438859, with SOx revised for the current lower sulfur content of diesel fuel.

NOx, CO, PM_{10}, VOC: No change.
SOx: (0.0019 lb/hr)(200 hr)(ton/2000 lb) = 0.00019 tpy

♦♦♦

RULE EVALUATION

The modification of the two turbines is expected to comply with all applicable SCAQMD rules and regulations, and federal and state regulations, as follows:

District Rules and Regulations

Rule 212—Standards for Approving Permits
Rule 2005(h) –Public Notice (RECLAIM) *(requires compliance with Rule 212)*
Rule 212 public notice is **not** required for this project, as discussed below.

- ***Rule 212(c)(1)***
  Public notice is required for any new or modified permit unit, source under Regulation XX, or equipment under Regulation XXX that may emit air contaminants located within 1000 feet from the outer boundary of a school. This subdivision shall not apply to a modification of an existing facility if the Executive Officer determines that the modification will result in a reduction of emissions of air contaminants from the facility and no increase in health risk at any receptor location. (This paragraph shall not apply to modifications that have no potential to affect emissions.)

  Analysis:
  This paragraph will **not** require public notice. Bicent Response Letter, 5/17/18, item 3 identified Pacific Boulevard Elementary School, 2660 E. 57^{th} St., Huntington park, CA 90255 as the nearest school. (This was also the nearest school for the most recent permit revision, A/N 517249 & 517250—Startup & Shutdown Revisions.) Based on UTM coordinates obtained from Google Earth Pro, the distance between the nearest stack outlet (south MGS

stack) and the northern boundary of the school was determined to be 2966 ft, which is farther than 1000 ft.

- ***Rule 212(c)(2)***
  Public notice is required for any new or modified facility which has on-site emission increases exceeding any of the daily maximums specified in subdivision (g) of this rule.

  Analysis:
  This paragraph will **not** require public notice because the on-site emission increases from the turbine upgrade project will exceed the daily maximum thresholds set forth in subdivision (g) for VOC, NOx, PM_{10}, and CO, as shown in the table below. For the purposes of this rule, an on-site emission increase is interpreted as an increase in the 30-day average.

Table 17 - Rule 212(c)(2) Applicability

	VOC	NOx	PM_{10}	SOx	CO	Lead
MGS 30-day average increase, lb/day *(Table 12)*	0	127 – 125 = 2	0 *	0	0	0
Rule 212(c)(2) Daily Maximum, lbs/day	30	40	30	60	220	3
Increase Exceed Daily Maximum?	No	No	No	No	No	No

***** The cooling tower PM_{10} emissions increase of 0.37 lb/day (6.61 lb/day – 6.24 lb/day) is not included. As the cooling tower is exempt from permitting, there is no 30-day average for the equipment.

- ***Rule 212(c)(3)***
  Public notice is required for any new or modified permit unit, source under Regulation XX, or equipment under Regulation XXX with increases in emissions of toxic air contaminants, for which the Executive Officer has made a determination that a person may be exposed to:
  (A) a maximum individual cancer risk greater than, or equal to:
    (i) one in a million (1×10^{-6}), per guidelines published by the Executive Officer under Rule 1401(e), for facilities with more than one permitted unit, source under Regulation XX, or equipment under Regulation XXX, unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million (10×10^{-6}) using the risk assessment procedures and toxic air contaminants specified under Rule 1402; or,

    (ii) ten in a million (10×10^{-6}), per guidelines published by the Executive Officer under Rule 1401(e), for facilities with a single permitted unit, source under Regulation XX, or equipment under Regulation XXX.

  Analysis: This paragraph will **not** require public notice. The *Rule 1401--New Source Review of Toxic Air Contaminants* analysis below indicates the maximum individual cancer risks (MICRs) for the sensitive receptor will be 0.34 in a million for Turbine No. 1 and 0.35 in a million for Turbine No. 2, both below the one in a million threshold

for public notice. The MICRs for the worker receptor, however, will be 1.09 in a million for Turbine No. 1 and 1.16 in a million for Turbine No. 2, both above the one in a million threshold for public notice. The total facility-wide MICR for the sensitive receptor will be 0.88 in one million and for the worker receptor will be 3.96 in one million. Although the MICRs for the worker receptor for both turbines will be greater than one in a million, the MICRs for the sensitive and worker receptors for the facility will be less than ten in a million. Therefore, public notice will not be required.

Rule 218 – Continuous Emission Monitoring

(b) Applicability and Monitoring Requirements for New, Modified and Existing CEMS

(1) The provisions of this Rule shall apply to all sources that require CEMS as specified in the regulations or permit conditions, with the following exceptions:

(A) This Rule shall not apply to CEMS subject to Regulation XX - "Regional Clean Air Incentives Market (RECLAIM)", Regulation IX - "New Source Performance Standards (NSPS)", Regulation X - National Emission Standards for Hazardous Air Pollutants (NESHAPS), or Regulation XXXI - "Acid Rain Program".

(B) This Rule shall not apply to CEMS subject to permit conditions where the purpose of the CEMS is to monitor the performance of the basic and/or control equipment and not to determine compliance with any applicable limit or standard.

(C) This Rule shall not apply to CEMS where alternative performance specifications are required by another District rule.

(2) The owner or operator of any equipment subject to this Rule shall provide, properly install, operate, and maintain in calibration and good working order a certified CEMS to measure the concentration and/or emission rates, as applicable, of air contaminants and diluent gases, flow rates, and other required parameters. The owner or operator shall also provide the necessary records and other data necessary to calculate air contaminant emission rates or concentrations, as specified in Rule 218, Sections (e) and (f).

Analysis: Each turbine is equipped with an oxidation catalyst to control CO emissions. A CO CEMS is required to be installed on each turbine to demonstrate compliance with the CO BACT limit of 2.0 ppmvd at 15% O_2 per Rule 1303(a)(1), required by condition A195.2. Therefore the CO CEMS are subject to Rule 218.

Further, the CO CEMS is required to demonstrate compliance with the monthly emissions limits in condition A63.3, as well as the startup and shutdown durations and emission limits set forth in condition A99.4 to minimize CO emissions for startups and shutdowns during which steady state BACT is not achievable.

Condition D82.1 currently requires a CEMS to measure CO concentration in ppmv, corrected to 15% O_2 on a dry basis, converted to lbs/hr and recorded on a continuous basis, over a 15-minute averaging period. Both CO CEMS's are certified in compliance with Rule 218. Rule 218 will be added as a rule tag.

(c) Requirements for New and Modified CEMS and SCEMS

(1) Application and Approval Requirements for New and Modified CEMS

(A) The owner or operator of any equipment subject to this Rule shall submit to the Executive Officer an "Application for CEMS" or "Application for CEMS Modification", as applicable. Any application submitted on or after May 14, 1999, shall require an initial approval by the Executive Officer prior to installation of a new CEMS or modification of an existing CEMS.… Within 90 days of installation, a person operating or using CEMS shall undertake a series of certification tests…. The purpose of the certification tests is to demonstrate the CEMS performance pursuant to the specifications in accordance with the provisions of Rule 218, Section (c)(1)(B). The owner or operator shall notify the Executive Officer in writing at least 14 days before the scheduled certification test dates. The certification tests shall be performed by a testing laboratory approved under the District Laboratory Approval Program. Data from such tests shall be submitted to the Executive Officer within 45 days following test completion. If satisfactory performance is demonstrated, final approval of the CEMS shall be granted. Subsequent operation and maintenance of the certified CEMS shall be in accordance with the provisions of Rule 218, Section (c)(1)(B). After final approval, modifications made to the CEMS shall be reviewed and approved by the Executive Officer according to the specifications stipulated in Rule 218, Section (c)(1)(B), and may require all or a portion of performance tests to be conducted.

(B) Upon submission of an "Application for CEMS" or "Application for CEMS Modification" as prescribed in Rule 218 Section (c)(1)(A), the applicant shall indicate either one of the following conditions:

(i) That the CEMS shall be reviewed and certified according to the provisions of Rule 218.1, "Continuous Emission Monitoring Performance Specifications", Section (b), and the subsequent operation and maintenance of the certified CEMS shall be in accordance with the provisions of Rule 218, Sections (b), (e), (f) and (g) and of the requirements of Rule 218.1(b) and (d), or,

(ii) That the CEMS shall be reviewed and certified according to the applicable provisions of the Code of Federal Regulations, Title 40 - "Protection of

Environment", Part 60 - "Standards of Performance for New Stationary Sources" (40CFR60), Appendix B - "Performance Specifications" (Appendix B), and the subsequent operation and maintenance of the certified CEMS shall be in accordance with the provisions of Rule 218, Sections (b), (e), (f) and (g), and the requirements of 40CFR60, Appendix F - "Quality Assurance Procedures" (Appendix F).
Notwithstanding the requirements of Section (c)(1)(B)(ii), any alternative test methods for 40CFR60, Appendices B and F shall be those that are listed in Rule 218.1, Table 1 - Reference Methods.

Analysis: Bicent is expected to continue to comply with Rule 218. The facility's *Continuous Emissions Monitoring System Quality Assurance/Quality Control (QA/QC) Plan* indicates that MGS had chosen to certify the CEMS according to the performance specifications of 40 CFR 60, Appendix B, Performance Specification 4A and is subject to the quality assurance requirements of 40 CFR 60, Appendix F.

(4) Quality Assurance/Quality Control Plan for New or Modified CEMS or SCEMS

(A) The owner or operator of CEMS or SCEMS who elects the performance specifications according to Rule 218, Section (c)(1)(B)(i), shall submit to the Executive Officer for approval a CEMS QA/QC Plan within 45 days of CEMS installation and no later than 30 days before the certification tests.

(B) Alternative Quality Assurance Practices
The owner or operator of CEMS or SCEMS who elects the performance specifications according to Rule 218, Section (c)(1)(B)(i), may choose to develop alternative CEMS operational test requirements to be included in the CEMS QA/QC procedures that assure data of equivalent or better quality. These alternative QA/QC procedures shall be submitted with the facility QA/QC Plan and are subject to the approval of the Executive Officer.

Analysis: Bicent is expected to continue to comply with Rule 218.

(e) Retention of Records for New, Modified and Existing CEMS and SCEMS

(1) The records of the data obtained from the CEMS recording devices shall clearly indicate concentrations or emission rates, or both, as specified by the Executive Officer. Records shall be maintained by the CEMS owner or operator for a minimum period of two years, unless otherwise specifically provided by another District regulation or permit conditions, and, shall be made available to the Executive Officer upon request.

(2) All calculations, raw parameter data used for calculations, records of the occurrence and duration of any start up, shutdown or malfunction, performance test, evaluation, calibration, adjustment and maintenance of the CEMS as well as calibration gas traceability shall be retained by the CEMS operator for a minimum period of two years unless otherwise specifically provided by another District regulation or permit conditions, and shall be made available to the Executive Officer upon request.

Analysis: Bicent is expected to continue to comply with Rule 218.

(3) Reports of CEMS Failure or Shutdown

(A) The CEMS owner or operator shall notify the Executive Officer within 24 hours or the next working day, in the event of a system failure or shutdown, which exceeds 24 hours. Zero and calibration checks and routine maintenance do not require reporting.

(B) In the case of a CEMS failure or shutdown, compliance with the provisions of Rule 218, Section (b) is waived for a period not to exceed 96 consecutive hours. Such waiver is extended beyond 96 consecutive hours only if a petition for an interim variance is filed in accordance with Regulation V and shall terminate at the time the Hearing Board acts upon such variance petition. CEMS owners or operators of qualified facilities may obtain a Hearing Board approval of an alternative operating condition following the established procedure in District Rule 518.2 - Federal Alternative Operating Condition.

Analysis: Bicent is expected to continue to comply with this provision.

Rule 219—Equipment Not Requiring a Written Permit Pursuant to Regulation II

- *Cooling Tower*

Rule 219(d)(3)(B) provides the following exemption for cooling towers.

(d) Utility Equipment - General

(3) Water cooling towers and water cooling ponds, both not used for evaporative cooling of process water or used for evaporative cooling of water from barometric jets or from barometric condensers and in which no chromium compounds are contained, including:

(A) Cooling towers used for comfort cooling; and

(B) Industrial cooling towers located in a chemical plant, refinery or other industrial facility, provided a filing pursuant to Rule 222 is submitted to the Executive Officer.

Analysis: The cooling tower continues to be exempted from permitting pursuant to subparagraph (d)(3)(B). As discussed below for subparagraph (s)(2)(A), the health

risk assessment supports the exemption. However, subparagraph (d)(3)(B) was amended on 5/5/17 to require the cooling tower to be Rule 222 registered. Consequently, SCAQMD AI Letter, 5/1/18, item 6.a. requested that Bicent file a registration application with the SCAQMD. SCAQMD AI Letter, 9/26/18, repeated the request. The cooling tower is now certified under Application No. 607874.

The cooling tower will not be added to *Process 6: Rule 219 Exempt Equipment Subject to Source Specific Rules* because it is not subject to a source specific rule found in SCAQMD Regulation XI.

- *Exceptions*
  Rule 219(s) provides exceptions from permit exemptions. Subparagraph (s)(2)(A) provides a possible exception for the cooling tower, as follows:

  (s) Exceptions
  Notwithstanding equipment identified in (a) through (r) of this rule, written permits are required pursuant to paragraphs (s)(1), (s)(2), and (s)(4), and filings are required under Rule 222 pursuant to paragraph (s)(3):

  (2) Equipment when the Executive Officer has determined that:
  (A) the risk will be greater than identified in subparagraph (d)(1)(A), or paragraphs (d)(2) or (d)(3) in Rule 1401 – New Source Review of Toxic Air Contaminants; or,
  (B) the equipment may not operate in compliance with all applicable District Rules and Regulations, including but not limited to SCAQMD Rule 402 – Nuisance.

  Once the Executive Officer makes such a determination and written notification is given to the equipment owner or operator, the equipment shall thereafter be subject to Rules 201 and 203 for non-RECLAIM sources, Rule 2006 for RECLAIM sources, and Regulation XXX – Title V Permits for major sources.

Analysis: The *Rule 1401--New Source Review of Toxic Air Contaminants* analysis below demonstrates the MICR for each of the three cells is less than one in a million, and the HIA and HIC for each cell is less than 1. Therefore, the cooling tower is exempt from permitting per Rule 219(d)(3)(B).

Rule 401 – Visible Emissions

This rule prohibits the discharge of visible emissions for a period aggregating more than three minutes in any one hour which is as dark or darker in shade than Ringelmann No. 1. Visible emissions are not

expected from the turbines because they will continue to be fired exclusively on pipeline quality natural gas.

Rule 402 – Nuisance

This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. Nuisance problems are not expected from the turbines and other equipment during normal operation. Further, the SCAQMD Complaint Tracking database shows the facility has not received any public complaints in the past five years.

Rule 403 – Fugitive Emissions

The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule includes the prohibition of fugitive dust emissions that remains visible in the atmosphere beyond the property line of the emission source.

During normal operations, fugitive emissions are not expected from the operation of the post-modification turbines and other equipment at the facility. Compliance with Rule 403 is expected.

Rule 407 – Liquid and Gaseous Air Contaminants

Paragraph (a)(1) limits CO emissions from equipment to 2000 ppmvd. The CO emissions from the turbines will continue to be controlled by an oxidation catalyst to the BACT limit of 2 ppmvd at 15% O_2. Compliance with the CO limit is expected.

Paragraph (c)(2) states the SO2 limits of paragraph (a)(2) do not apply to equipment that complies with the gaseous fuel sulfur content limits of Rule 431.1. The turbines will be fired by natural gas that complies with the sulfur limit in Rule 431.1, as discussed below.

Rule 409 – Combustion Contaminants

This rule restricts combustion generated particulate matter emissions from combustion equipment to 0.23 grams per cubic meter (0.1 grain per cubic foot) of gas, calculated to 12% CO_2, averaged over a minimum of 15 consecutive minutes.

P. 36 of the FDOC calculated the grain loading as 0.0069 gr/scf PM_{10} based on 3.89 lb/hr PM_{10}. For the turbine upgrade project, the PM_{10} emission rate will be reduced from 3.89 lb/hr to 3.386 lb/hr based on recent source tests. Therefore, the grain loading is expected to be 0.006 gr/scf < 0.1 gr/scf limit.

Rule 431.1 – Sulfur Content of Gaseous Fuels

The natural gas supplied to the gas turbines is expected to comply with the 16 ppmv sulfur limit (calculated as H2S) specified in this rule, because commercial grade natural gas has an average sulfur content of 4 ppm.

Rule 474—Fuel Burning Equipment - Oxides of Nitrogen

This rule is superseded by NOx RECLAIM pursuant to *Rule 2001, Table 1—Rules Not Applicable To RECLAIM Facilities For Requirements Pertaining To NOx Emissions If Rule Was Adopted Or Amended Prior To October 5, 2018*.

Rule 475 – Electric Power Generating Equipment

This rule applies to power generating equipment having a maximum rating of more than 10 net MW, for which a permit to build, erect, install or expand is required after May 7, 1976. Combustion contaminants (particulate matter) are limited to 11 lb/hr or 0.01 grain/scf. Compliance is achieved if either the mass limit or the concentration limit is met.

The calculations for Rule 475 are different than for Rule 409. As the FDOC did not provide calculations for Rule 475, the PM_{10} emissions are calculated below for the post upgrade turbines.

Combustion Particulate (gr/scf) = (PM_{10}, lb/hr / Stack Exhaust Flow, scf) * 7000 gr/lb

PM_{10} = 3.386 lb/hr

Stack exhaust flow = 13.57 E +06 scf/hr (from Rule 409 analysis in FDOC, p. 36)

Combustion Particulate = (3.386 / 13.57 E +06) * 7000 = 0.0017 gr/scf < 0.01 gr/scf limit

Rule 1134 – Emissions of NOx from Stationary Gas Turbines

This rule is superseded by NOx RECLAIM pursuant to *Rule 2001, Table 1—Rules Not Applicable To RECLAIM Facilities For Requirements Pertaining To NOx Emissions If Rule Was Adopted Or Amended Prior To October 5, 2018*, until the proposed amended rule is adopted at a Public Hearing before the SCAQMD Governing Board, currently scheduled for April 5, 2019.

Subsequent to the adoption of the proposed amended rule, this rule will not be applicable to Bicent because subdivision (b) is proposed to be revised as follows:

(b) Applicability

The provisions of this rule shall apply to all ~~existing~~ stationary gas turbines, 0.3 megawatt (MW) and larger~~, as of August 4, 1989~~. The rule does not apply to stationary gas turbines subject to Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities, located at petroleum refineries, landfills, or publicly owned treatment works or fueled by landfill gas.

As the turbines are subject to Rule 1135, they will not be subject to Rule 1134.

Rule 1135 – Emissions of Oxides of Nitrogen from Electricity Generating Facilities, amended November 2, 2018

(b) Applicability
This rule shall apply to electric generating units at electricity generating facilities.

(c) Definitions
(7) ELECTRIC GENERATING UNIT means a boiler that generates electric power, gas turbine that generates electric power with the exception of cogeneration turbines, or diesel internal combustion engine that generates electric power and is located on Santa Catalina Island with the exception of emergency internal combustion engines.

Analysis: The gas turbines generate electric power and are subject to this rule.

(d) Emissions Limitations Limits
(1) Emissions Limits for Boilers and Gas Turbines
Notwithstanding the exemptions contained in Rule 2001 – Applicability, subdivision (j) – Rule Applicability and its accompanying Table 1: Existing Rules Not Applicable to RECLAIM Facilities for Requirements Pertaining to NOx Emissions, on and after January 1, 2024, or when required by a permit to operate issued to effectuate the requirements in this rule, whichever occurs first, the owner or operator of an electricity generating facility shall not operate, a boiler or gas turbine in a manner that exceeds the NOx and ammonia emissions limits listed in Table 1: Emissions Limits for Boilers and Gas Turbines, where:

(B) Boilers and gas turbines installed or for which the owner or operator has applied for permits to construct prior to November 2, 2018 shall:
(i) Average the NOx and ammonia emissions limits in Table 1 over a 60 minute rolling average; or
(ii) Retain the averaging time requirements specified on the SCAQMD permit as of November 2, 2018.

Table 1: Emissions Limits for Boilers and Gas Turbines

Equipment Type	NO_x (ppmv)[1]	Ammonia (ppmv)	Oxygen Correction (%, dry)
Combined Cycle Gas Turbine And Associated Duct Burner	2	5	15

1 – The NO_x emission limits in Table 1 shall not apply during start-up, shutdown, and tuning.

Analysis: Subparagraph (d)(1)(B) is applicable because the initial applications for P/Cs for the turbines were submitted on 12/7/01. As condition A195.1 limits NOx to 2 ppmv and condition A195.4 limits ammonia to 5 ppmv, both averaged over 1 hour at 15% O2, the turbines are in compliance with (d)(1)(B).

(3) Start-up, Shutdown, and Tuning Requirements
The owner or operator of an electricity generating facility shall meet start-up, shutdown, and tuning requirements in the SCAQMD permit for each electric generating unit. On and after January 1, 2024, the SCAQMD permit shall include limitations for duration, mass emissions, and number of start-ups, shutdowns, and, if applicable, tunings.

Analysis: As condition nos. A99.3 and A99.4 limit the duration, mass emissions, and number of start-ups and shutdowns for NOx and CO, respectively, the turbines are in compliance with (d)(3).

(e) Monitoring, Recordkeeping, and Reporting

(1) RECLAIM NOx Source
The owner or operator of each RECLAIM NOx source subject to Rule 1135 shall comply with SCAQMD Rule 2012 – Requirements for Monitoring, Reporting, and Recordkeeping for Oxides of Nitrogen (NOx) Emissions to demonstrate compliance with the NOx emissions limits of this rule.

Analysis: Bicent is currently in RECLAIM and required to comply with Rule 2012.

(6) Ammonia Emissions Limits

(A) The owner or operator of each electric generating unit with catalytic control devices shall conduct quarterly source tests to demonstrate compliance with the ammonia emission limit according to SCAQMD Method 207.1 – Determination of Ammonia Emissions from Stationary Sources during the first twelve months of operation of the catalytic control device and annually thereafter when four consecutive quarterly source tests demonstrate compliance with the ammonia emission limit. If an annual test is failed, four consecutive quarterly source tests must demonstrate compliance with the ammonia emissions limits prior to resuming annual source tests.

Analysis: Condition D29.3 requires ammonia tests to be conducted at least once every calendar quarter for the first year and annually thereafter. For the turbine upgrade project, condition D29.3 will be revised to reset the annual source testing requirement for NH3 to require an initial source test within

180 days after startup of the turbine upgrade modification. The next source test for NH3 will be required annually after the initial source test.

Note: For Section D (Permits to Operate), condition D29.3 will remain unchanged. For new Section H (Permits to Construct), condition D29.3 will become new condition D29.5 and incorporate the updates and revisions resulting from the turbine upgrade project.

Regulation XIII—New Source Review (NSR)

This regulation sets forth BACT, modeling, offset, and other requirements for non-attainment pollutants. The SCAQMD is not in attainment for PM_{10} (California 24-hr and California annual standards), $PM_{2.5}$ (federal 24-hr, and California and federal annual standards), and ozone. The SCAQMD is in attainment for PM_{10} (federal 24-hr standard), CO, NOx, and SOx. Since NOx, SOx, and VOC (no attainment standards for VOC) are precursors to non-attainment pollutants, they are treated as non-attainment pollutants as well. Specifically, NOx and VOC are precursors to ozone. NOx and SOx are precursors to PM_{10} and $PM_{2.5}$. Thus, the non-attainment pollutants are NOx, PM_{10}, $PM_{2.5}$, SOx, VOC, ozone depleting compound, and ammonia for the purposes of New Source Review.

The rules are based on both the National Ambient Air Quality Standards (NAAQS) and the California Ambient Air Quality Standards (CAAQS). The NAAQS are the levels of air quality necessary, with an adequate margin of safety, to protect the public health.

- ***Rule 1303(a)(1)—BACT/LAER (PM_{10}, SOx, VOC))***
- ***Rule 2005(c)(1)(A)—BACT/LAER (NOx)*** (*requires BACT for NOx for RECLAIM)*
- ***Rule 1701(b)—BACT/LAER (CO)*** *(requires BACT for CO for all facilities)*

Rule 1303(a)(1) sets forth the BACT requirements, as follows:

(a) Best Available Control Technology (BACT):

(1) The Executive Officer or designee shall deny the Permit to Construct for any relocation or for any new or modified source which results in an emission increase of any nonattainment air contaminant, any ozone depleting compound, or ammonia, unless BACT is employed for the new or relocated source or for the actual modification to an existing source.

(2) In implementing subdivision (a), the Executive Officer or designee shall periodically publish guidelines indicating the administrative procedures and requirements for commonly permitted sources. BACT for other source categories shall be determined using the definition of BACT in Rule 1302 and the general administrative procedures and requirements of the BACT Guidelines. BACT for sources located at major polluting facilities shall be at least as stringent as Lowest Achievable Emissions Rate as defined in the federal Clean Air Act Section 171(3) [42 U.S.C. Section 7501(3)]. When

updating the BACT guidelines to become more stringent for sources not located at major polluting facilities, economic and technical feasibility shall be considered in establishing the class or category of sources and the applicable requirements.

(3) BACT for sources not located at major polluting facilities shall be as specified in the BACT Guidelines for such source categories, unless the BACT specified in the guideline is less stringent than required by state law in which case BACT shall be as defined in state law considering economic and technical feasibility.

(4) The BACT requirements of this paragraph shall apply regardless of any modeling or offset exemption in Rule 1304.

Rule 1302(h) defines BACT as "the most stringent emission limitation or control technique which:

(1) has been achieved in practice [AIP] for such category or class of source; or

(2) is contained in any state implementation plan (SIP) approved by the US EPA approved by the United States Environmental Protection Agency (EPA) for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitation or control technique is not presently achievable; or

(3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board."

The first two requirements in the BACT definition are required by federal law, as LAER for major sources. The third part of the definition is unique to SCAQMD and some other areas in California, and allows for more stringent controls than LAER.

Rule 2005(c)(1)(A) sets forth the BACT requirements for existing RECLAIM facilities, as follows:

(c) Requirements for Existing RECLAIM Facilities, Modification to New RECLAIM Facilities, Facilities which Undergo a Change of Operator, or Facilities which Increase an Annual Allocation to a Level Greater Than the Facility's Starting Allocation Plus Non-tradable Credits.

(1) The Executive Officer shall not approve an application for a Facility Permit Amendment to authorize the installation of a new source or modification of an existing source which results in an emission increase as defined in subdivision (d), unless the applicant demonstrates that:

(A) Best Available Control Technology will be applied to the source;…

SCAQMD policy requires BACT only for emission increases greater than or equal to one (1.0) pound per day. Further, the SCAQMD Governing Board adopted a Clean Fuels Policy that included a requirement to use clean fuels as part of BACT. A clean fuel is one that produces air emissions equivalent to or lower than natural gas for NOx, SOx, ROG, and fine respirable particulate matter (PM_{10}).

Rule 1303(a) sets forth different requirements for major polluting facilities and non-major polluting (minor) facilities.

- Rule 1302(s) defines "*Major Polluting Facility*" to mean "any facility located in the South Coast Air Basin (SOCAB) which emits or has the potential to emit the following amounts or more:

  Volatile Organic Compounds (VOC) (10) tons per year
  Nitrogen Oxides (NOx**)** (10) tons per year
  Sulfur Oxides (SOx) (70) tons per year
  Particulate Matter (PM_{10}) (70) tons per year
  Carbon Monoxide (CO) (50) tons per year…."

- Rule 1302(t) defines "*Minor Facility*" to mean "any facility that is not a major polluting facility."

The following table summarizes the analysis that the existing MGS is a "major polluting facility" for the purposes of NSR.

Table 18—New Source Review Major Polluting Facility Applicability

	NOx	**PM_{10}**	**SO_x**	**VOC**	**CO**
MGS Potential to Emit, TPY (*Table 15—Facility Maximum Annual Emissions, Pre-Modification*)	40.65	29.26	1.28	19.42	45.82
Potential to Emit Exceeds Threshold?	Yes, potential to emit is greater than 10 tpy.	No, potential to emit is less than 70 tpy.	No, potential to emit is less than 70 tpy.	Yes, potential to emit is greater than 10 tpy.	No, potential to emit is less than 50 tpy.
Major Polluting Facility?	Yes, the PTEs for NOx and VOC are greater than the respective major source thresholds.				

If a source is a major polluting facility for any one criteria pollutant, it is considered a major polluting facility for all criteria pollutants. As shown in the table above, the existing MGS is a major polluting facility. Thus, Rule 1303(a)(1) requires BACT/LAER for the non-attainment pollutants, NOx, $PM_{10}/PM_{2.5}$, SO_2, VOC, and ammonia. Rule 2005(c)(1)(A) requires BACT/LAER for NOx. As discussed below, Rule 1701(b) requires BACT/LAER for CO.

SCAQMD staff determines LAER requirements on a permit-by-permit basis based on the definition of LAER. In essence, LAER is the most stringent emission limit or control technology that is:

- found in a state implementation plan (SIP), or
- achieved in practice (AIP), or
- is technologically feasible and cost effective.

The SCAQMD performed a BACT/LAER analysis for combined-cycle turbines for the Alamitos Energy Center Final Determination of Compliance (FDOC) in 2016. The analysis included a comprehensive review of the USEPA RACT/BACT/LAER Clearinghouse, Statewide Best Available Control Technology (BACT) Clearinghouse, and other databases. The "Alamitos Energy Center (AEC) Final Determination of Compliance (FDOC) Package," was docketed on the CEC website on 11/18/16 for the Alamitos Energy Center, Docket No. 13-AFC-01 (https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=13-AFC-01).

The following table compares the BACT/LAER emission limits for combined-cycle turbines from the Alamitos Energy Center FDOC and the current permitted BACT/LAER limits for the MGS facility.

Table 19 - Combined-Cycle Gas Turbine BACT/LAER Requirements & MGS Permitted Emissions Levels

	NOx	CO	VOC	PM_{10}/SOx	NH_3
BACT/LAER Limits for Combined-Cycle Turbines	2.0 ppmvd at 15% O_2, 1-hr average	1.5 ppmvd at 15% O_2, 1-hr average	2.0 ppmvd at 15% O_2, 1-hr average	PUC quality natural gas with sulfur content ≤ 1 grain/100 scf	5.0 ppmvd at 15% O_2, 1-hr average
MGS Permitted BACT/LAER Limits	Condition A195.1: 2.0 ppmvd at 15% O_2, 1-hr average	Condition A195.2: 2.0 ppmvd at 15% O_2, 3-hr average	Condition A195.3: 2.0 ppmvd at 15% O_2, 1-hr average	Natural gas required in equipment description.	Condition A195.4: 5.0 ppmvd at 15% O_2, 1-hr average

The MGS permitted limits are in accord with all current BACT/LAER limits, except for CO. As discussed under *Regulation XVII—Prevention of Significant Deterioration* below, although Bicent is <u>not</u> subject to PSD review for NOx, SO_2, PM_{10} and CO, Rule 1701(b)(1) provides that the BACT requirement for CO applies to a net emission increase of a criteria air contaminant from a permit unit at any stationary source. The CO daily emissions increase resulting from <u>A/N 517249 & 517250—Startup & Shutdown Revisions</u>, and from <u>A/N 598922 & 598923—Turbine Upgrade</u> are

calculated below to determine whether the increase was or will be 1 lb/day or greater, which would trigger the requirement for then current or presently current BACT/LAER for CO.

CO Emission Increases

- A/N 394164 & 394165--FDOC
  From p. 25 of FDOC:

  As discussed for the emissions calculations above, the maximum emission rates for normal operation are for Scenario S13 (100% load, 38 °F ambient).

  Maximum daily emissions for CO = 2 hrs (cold start) + 21.5 hrs (normal operation) + 0.5 hr shutdown = 24.50 lbs, cold start + (21.5 hr x 2.48 lb/hr, normal operation) + 4.75 lbs, shutdown = 82.57 lbs/day

  In 2002, BACT for CO was 2 ppm, 3-hour averaging, as set forth in condition A195.2.

- A/N 517249 & 517250—Startup & Shutdown Revisions
  The number of startups increased from 1 to 2 per day, and the emissions for cold start, warm start, and shutdown were revised.

  Maximum daily emissions for CO = 2 hrs (cold start) + 1.5 hr (warm start) + 20.0 hrs (normal operation) + 0.5 (shutdown) = 204.8 lbs, cold start + 59.9 lbs, warm start + (20.0 hr x 2.48 lb/hr, normal operation) + 10.8 lbs, shutdown = 325.10 lbs/day

  Increase = 325.10 lb/day – 82.57 lb/day = 242.53 lb/day

  In 2013, the BACT for CO was 2 ppm CO, 1-hour averaging.

- A/N 598922 & 598923—Turbine Upgrade
  The normal operating emission rate increased due to the turbine upgrade modification.

  Maximum daily emissions for CO = 2 hrs (cold start) + 1.5 hr (warm start) + 20.0 hrs (normal operation) + 0.5 (shutdown) = 204.8 lbs, cold start + 59.9 lbs, warm start + (20.0 hr x 2.529 lb/hr, normal operation) + 10.8 lbs, shutdown = 326.08 lbs/day

  Increase = 326.08 lbs – 325.10 lbs = 0.98 lb/day

  In 2017, the BACT for CO became 1.5 ppm CO, 1-hour averaging.

  Sr. Engineer Tom Lee of the SCAQMD BACT Team confirmed that an increase of 0.98 lb/day is less than 1.0 lb/day and will not trigger new BACT.

Conclusion: As the turbine upgrade project resulted in a daily emission increase of 0.98 lb/hr, a BACT limit decrease from 2 ppm to 1.5 ppm is not required. However, as A/N 517249 & 517250 for the startup/shutdown revisions resulted in a daily

emission increase of 242.53 lb/day, a decrease in averaging time from 3-hour to 1-hour was required and will be incorporated into condition A195.2.

SCAQMD AI Letter, 9/26/18, item 14 provided a discussion regarding why condition A195.2 will be revised to decrease the averaging time from 3-hour to 1-hour. On

Note: For Section D (Permits to Operate), conditions A195.1. A195.2, and A195.3 will remain unchanged. For new Section H (Permits to Construct), these conditions will become new conditions A195.5, A195.6, and A195.7 and incorporate all the updates and revisions resulting from the turbine upgrade project.

♦♦

- ***Rule 1303(b)(1)—Modeling (CO, PM_{10} & SOx)***
- ***Rule 2005(c)(1)(B)—Modeling (RECLAIM NOx)***

Rule 1303(b)(1) requires air dispersion modeling for NO_2 (non-RECLAIM), CO, PM_{10}, and SO_2. The Executive Officer or designee shall, except as Rule 1304 applies, deny the Permit to Construct for any new or modified source which results in a net emission increase of any nonattainment air contaminant at a facility, unless the applicant substantiates with air dispersion modeling that the new facility or modification will not cause a violation, or make significantly worse an existing violation according to Appendix A of the rule, or other analysis approved by the Executive Officer or designee, of any state or national ambient air quality standards at any receptor location in the District. As the Rule 1303 Appendix A standards are outdated, the modeling analyses are required to be based on current ambient air quality standards.

Compliance determination is different for attainment and nonattainment pollutants. For attainment pollutants, NO_2, CO, SO_2, PM_{10} (federal 24-hr standard only), the maximum modeled concentration plus the worst-case background concentration shall not exceed the most stringent air quality standard. For non-attainment pollutants, PM_{10} and $PM_{2.5}$, where the background concentrations exceed the ambient air quality standards, the maximum modeled concentration shall not cause an exceedance of the Rule 1303 significant change threshold. The South Coast Air Basin is designated non-attainment for PM_{10} (California 24-hr and California annual standards), and $PM_{2.5}$ (federal 24-hr, and California and federal annual standards).

Rule 2005(c)(1)(B) requires modeling for NO_2 per permit unit (turbine) for RECLAIM facilities. For A/N 394164 & 394165—Modeling Analysis for FDOC and A/N 517249 & 517250--Modeling Analysis For Startup & Shutdown Revisions, the NO_2 modeling was performed per turbine and will be summarized under Rule 2005(c)(1)(B) below. For A/N 598922 & A/N 598923—Turbine Upgrade, the NO_2 modeling was included in the facility-wide modeling provided for Rule 1303(b)(1) and will be summarized below.

1. **A/N 598922—Modification to Turbine No. 1**
2. **A/N 598923—Modification to Turbine No. 2**

A. Initial: A/N 394164 & 394165—FDOC

The FDOC provided the Rule 1303(b)(1) modeling analysis for CO and PM_{10} on pp. 40 - 43. The Planning, Rule Development & Area Sources staff modeling review memo, dated 5/28/02, for the air quality modeling and health risk assessment is on pp. 76-79 of the FDOC. Modeling was not provided for SOx.

The applicant provided modeling analysis for maximum project impacts for CO and PM_{10} using ISCST3 dispersion model (version 00101) and representative meteorological data from the Vernon meteorological station. At that time, CO was a nonattainment pollutant and compliance was evaluated accordingly.

The applicant provided a modeling analysis for one turbine, but was requested to provide a modeling analysis for two turbines operating simultaneously because Rule 1303(b)(1) requires compliance for a "new facility." The two turbines were the only equipment for the new facility that required modeling. The emergency ICE for the firewater pump was exempt from modeling analysis pursuant to Rule 1304. The cooling tower was exempt from permitting pursuant to Rule 219. The applicant complied by doubling the impact of one turbine to predict the impact of two turbines, a conservative approach, for the worst case scenarios.

The CEC required the applicant to provide air dispersion modeling and HRA for the fire pump. (The FDOC did not include a discussion of the fire pump modeling required by the CEC.)

The maximum ground level impacts were evaluated for four scenarios--commissioning, startup, normal operation, and normal shutdown, each with different operating conditions and emission rates--to determine the worst case for impacts.

Four Scenarios—Maximum Emissions for Each Scenario

A description of the four scenarios and a tabulation of the maximum emissions for each scenario are presented below. The emissions are used as input data for the modeling analysis.

1. Commissioning Scenario

   During commissioning, CO emissions are higher than normal because the combustors are not optimally tuned and/or the SCR/CO control may not be fully functional. For $PM_{10,}$ the emission factor (lb/mmscf) remains constant and the commissioning emissions rate reflects the gas usage.

The following table sets forth the maximum hourly emissions for the commissioning of one turbine.

Table 20 - Maximum Hourly Emissions for Commissioning of One Turbine (A/N 394164 & 394165-FDOC)

Pollutant	Emissions, lb/hr
CO	33.0[1]
PM_{10}	4.04[2]

Ref: Tables 3-7, 3-8 and Appendix B1 of Application for Permit to Construct

[1] The maximum hourly CO emissions occur under low load conditions when the control equipment is not tuned.

[2] The maximum hourly PM_{10} emissions occur under high load due to higher fuel use. Also, the PM_{10} emissions rate and modeling were based on the original estimate of 80% conversion of SO_2 to SO_3 through the CO catalyst and SCR, with SO_3 turning into PM_{10} (ammonium sulfate). The 80% conversion was later refined to 53% conversion, which was used for the emissions calculations above. Since the modeling based on the 80% conversion indicated compliance, it was not necessary to revise the modeling to base emissions on the 53% conversion.

Air dispersion modeling was performed to estimate 1-hour and 8-hour average concentrations. 1-hour and 8-hour concentrations were estimated using maximum 1-hour emission rates.

2. Startup Scenarios

The three types of startups vary in duration: CO (2 hour), warm (1.5 hour), and hot (1 hour). Startup is necessary to heat the HRSG and SCR/CO catalyst. During startup, CO emissions are higher than normal operation emissions because the control equipment has not reached optimal temperature to control to BACT level. The manufacturer provided the CO emissions data for different startup scenarios. For PM_{10}, the emission factor (lb/mmscf), estimated from AP-42, remains constant and the startup emissions rate reflected the gas usage.

The following table sets forth the maximum hourly emissions for startup for one turbine.

Table 21 - Maximum Hourly Emissions for Startup for One Turbine (A/N 394164 & 394165-FDOC)

Pollutant	Emissions Cold Start	Emissions Warm Start	Emissions Hot Start
CO	24.30 lb/hr[1]	9.84 lb/hr	6.63 lb/hr
PM_{10}	4.08 lb/hr[2]	2.41 lb/hr	2.04 lb/hr

Ref: Appendices B2, B3 and B4 of Application for Permit to Construct

[1] The maximum hourly CO emissions would occur under the first hour of cold startup when the catalyst is not warmed up.

[2] The maximum hourly PM_{10} emissions occur during cold start due to higher fuel use. Since this modeling is based on the 80% conversion of SO_2 to SO_3 (SO_3 converts to ammonium sulfate (PM_{10})) indicated compliance, it was not necessary to revise the modeling to base emissions on the later more refined 53% conversion.

3. Normal Operation Scenario

As discussed above under Emissions Calculations, the highest CO and PM_{10} hourly emissions occur under Scenario S13 (100% load, 38 °F ambient). CO emissions are based on the BACT requirement of 2 ppmvd at 15% O2. PM_{10} emissions are estimated from the AP-42 emission factor and gas usage. PM_{10} emissions also include the conversion of SO_2 to PM_{10} in the SCR/CO catalyst system (see footnote 3 for the table below).

The following table sets forth the maximum hourly and annual emissions for normal operation for one turbine.

Table 22 - Maximum Hourly and Annual Emissions for Normal Operation for One Turbine (A/N 394164 & 394165-FDOC)

Pollutant	Maximum Emissions, lb/hr[1]	Annual Emissions, lb/yr[2]
CO	2.46	21,550
PM_{10}[3]	4.95	43,362

Ref: Appendix B5, S13 of Application for Permit to Construct

[1] Based on fuel consumption at full load.

[2] Based on annual operation of 8760 hrs.

[3] Since this modeling based on the 80% conversion of SO_2 to SO_3 (SO_3 converts to ammonium sulfate (PM_{10})) indicated compliance, it was not necessary to revise the modeling to base emissions on the later more refined 53% conversion, which resulted in PM_{10} emissions rate of 3.89 lb/hr

4. Shutdown Scenario

During shutdown, the CO emissions are higher as the SCR/CO oxidation catalyst is being shut down. The shutdown emissions occur for the worse case at 38 °F.

The following table sets forth the maximum hourly emissions for normal shutdown, calculated as the emissions during the 30-minutes of shutdown, for one turbine.

Table 23 - Maximum Hourly Emissions for Normal Shutdown for One Turbine (A/N 394164 & 394165-FDOC)

Pollutant	Emissions, lb/hr*
CO	4.75
PM_{10}	0.96

Ref: Appendix A6, SH1, Supplement for Application for Permit to Construct

Maximum Ground Level Impacts

For CO, the worst case 1-hour and 8-hour emissions occur when both turbines are in commissioning mode simultaneously. For PM_{10}, the worst case 24-hour PM_{10} emissions occur when both turbines are in normal operation under Scenario S13 (100% load, 38 °F ambient). The applicant provided modeling analysis to determine the maximum ground level impact for one turbine, then doubled this impact to estimate the impact for two turbines for the worst case as shown in the table below.

Table 24 - CO and PM_{10} Modeling Results
(A/N 394164 & 394165-FDOC)

Pollutant	Averaging Period	Significant Change in Air Quality Concentration, μg/m³	Commissioning μg/m³		Startup μg/m³		Normal μg/m³		Shutdown μg/m³
			1 CT	2 CT[1]	1 CT	2 CT	1 CT	2 CT[2]	1 CT
CO	1-hour	1,100	45.8	**91.6**	30.2	60.4	2.4		5.8
	8-hour	500	19.6	**39.2**	ND	ND	0.9		ND
PM_{10}	24-hour	2.5	0.7	--	ND	ND	0.8	1.6	ND
	Annual Geometric Mean	1.0	ND[3]	ND	ND	ND	0.2	0.4	ND

Ref: Tables 9, 11, 12 & 13 of Attachment 1, Application for Permit to Construct

1 Worst case for CO.
2 Worst case for PM_{10}.
3 ND: Not done. According to the applicant, these cases were left out because their short durations were not relevant for the given averaging period.

Conclusion

As demonstrated in the table above, the maximum ground level impacts for the simultaneous commissioning or operation of the two turbines are below the significant change thresholds for both CO (1-hr and 8-hr) and PM_{10} (24-hr and annual geometric mean). Therefore, the CO and PM_{10} air quality impacts were determined to comply with Rule 1303.

B. Pre-Modification: A/N 517249 & 517250--Startup & Shutdown Revisions

On 12/19/07, the City of Vernon submitted a Petition to the CEC to increase cold startup emission limits for NOx and CO based on previous exceedances, but did not include new modeling. CEC Order No. 08-813-4, dated 8/13/08, approved the Petition to Modify Condition AQ-C10 Regarding Air Emission Limits Related to Cold Startups, with the proposed emission limits, as modified by CEC staff. For NOx, the 13.1 lb/hr per turbine and 15.75 lb/cold start in the FDOC were increased to 27.5 lb/hr and 122.8 lb/cold start, respectively. For CO, the 24.3 lb/hr per turbine and 24.5 lb/cold start in the FDOC were increased to 70 lb/hr and 204.8 lb/cold start. The CEC accepted the applicant's proposed modeling results which were estimated by multiplying the original modeling results for the 1-hour average for NOx and CO by the ratio of the proposed increased maximum hourly

emissions rate to the original maximum hourly emissions rate. However, applications were not also submitted to the SCAQMD.

On 12/16/10, the facility submitted A/N 517249 and 517250 to revise conditions A99.3 and A99.4 but did not provide a modeling analysis. The revisions included the incorporation of the increases in NOx and CO emissions for cold starts, previously approved by the CEC. The applicant requested 56 total startups with a maximum of 30 cold starts per turbine per year, a change from the 56 total startups, 4 cold and 52 warm per turbine per year in the FDOC. Additional changes included an increase in maximum hourly CO emissions for cold and non-cold starts, as well as an increase to two startups per day. PM_{10} emissions are proportional to fuel usage and were not affected by the startup and shutdown related changes.

Four Scenarios—Maximum Emissions for Each Scenario

1. Commissioning Scenario
   Same as FDOC.

2. Startup Scenarios
   For the FDOC, the CO model results for startup were based on the maximum hourly emissions for cold startup, because cold start emissions are higher than warm start and hot start emissions rates.

The following table sets forth the increase in maximum hourly emissions for cold startup for **two** turbines to determine whether two turbines may be started up simultaneously.

Table 25 - Maximum Hourly Emissions for Cold Startup for Two Turbines (A/N 517249 & 517250-Startup & Shutdown Revisions)

Pollutants	Maximum Hourly Emissions [1]	
	FDOC	CEC Order No. 08-813-4 [2]
CO	24.3 lb/hr-turbine x 2 turbines = 48.6 lb/hr for two turbines	140 lb/hr for two turbines (equal to 70 lb/hr for one turbine)

[1] The maximum hourly CO emissions occur under the first hour of cold startup when the catalyst is not warmed up.
[2] The District has not previously evaluated the effect of the CEC's approved emissions limit increases.

3. Normal Operation Scenario
   Same as FDOC.

4. Shutdown Scenario
   The increase in shutdown emissions did not need to be evaluated because shutdown emissions are lower than startup emissions.

Maximum Ground Level Impacts

- *1-Hr Average*

  For the FDOC, the cold startup impact for 1 CT was 30.2 µg/m^3 based on 24.3 lb/hr. Based on the subsequent CEC Order, the maximum hourly emissions for one turbine was increased from 24.3 lb/hr to 70 lb/hr.

  The Petition filed by the City of Vernon on 12/19/07 to increase cold startup emissions limits for NOx and CO did not include new modeling. The proposed modeling results were estimated by multiplying the original modeling results by the ratio of the proposed increased maximum hourly emissions rate to the original maximum hourly emissions rate. These estimated model results were provided by the same consultant who had prepared the original project application and performed the original modeling. CEC staff accepted the consultant's proposed methodology for estimating revised modeling results and revised the limits proposed by the City as set forth in its Staff Analysis.

  For the engineering evaluation, the same methodology based on ratios were used to estimate the effect of the increase in maximum hourly emissions on ground level impact.

  Two Turbines
  (60.4 µg/m^3) (140 lb/hr / 48.6 lb/hr) = 174 µg/m^3

  Since CO was now an attainment pollutant, the project impact plus the background concentration was required to not exceed the most stringent air quality standard. The above estimated increase in modeling results for two turbines is reflected in the table below. Then program supervisor Tom Chico provided the background concentration for 1-hr CO for the Vernon area based on the peak concentrations at the downtown LA station (Station No. 087) over the three year period, 2009-2011.

Table 26 - CO Modeling Results (1-hr Average) for Two Turbines (A/N 517249 & 517250-Startup & Shutdown Revisions)

Scenario	Modeled Concentration µg/m^3	Background Concentration µg/m^3	Modeled + Background Concentrations µg/m^3	State Standard µg/m^3	Federal Standard µg/m^3
Commissioning	Same as FDOC.				
Startup	174	3450	3624	23,000	40,000
Normal	Same as FDOC.				
Shutdown	Not evaluated because shutdown emissions are lower than startup emissions.				

Conclusion

As shown the table above, the estimated CO air quality impact for two turbine startups added to the background CO concentration is less than the most stringent CO air quality standards for the 1-hr average. Therefore, the CO air quality impact was determined to continue to comply with Rule 1303 when two turbines are started up simultaneously.

♦♦

C. Post-Modification: A/N 598922 & A/N 598923—Turbine Upgrade

The Application for turbine upgrade provided a facility-wide air dispersion modeling analysis for NOx, SO_2, CO, and $PM_{10}/PM_{2.5}$ on pp. 1-27 to 1-37 of the Application. The modeling analysis includes the two turbines, the fire pump, and the cooling tower. The prior SCAQMD dispersion analyses did not include the fire pump and the cooling tower because the emergency engine is exempt from modeling requirements per Rule 1304(a)(4), and the cooling tower is exempt from permitting per Rule 219(d)(3). The facility-wide dispersion analysis was provided for and reviewed by the SCAQMD in support of CEC's CEQA analysis.

The reasons for providing the modeling analysis are:

(1) The NOx, SO_2, CO, and $PM_{10}/PM_{2.5}$ hourly emission rates from each turbine will change with the turbine upgrade project. In addition, the modeling incorporates the startup and shutdown related emissions revisions incorporated into conditions A99.3 and A99.4 by A/N 517249 and 517250 for which modeling was not provided.

(2) Revise Condition of Certification AQ-C7 for limiting the PM_{10} emissions from the cooling tower from 6.2 lb/day to 7.3 lb/day.

> **Note**: *Bicent Response Letter, 10/20/18, item 6.b.iii. acknowledged the water analysis indicated the Total Dissolved Solids of the cooling tower water was actually 1020 mg/liter, not the 1125 mg/l used to calculate the 7.3 lb/day. Therefore, based the correct 1020 mg/liter, the PM_{10} limit should be increased to 6.6 lb/day.*

(3) Revise Condition of Certification AQ-C8 from prohibiting fire pump testing on the same day as a turbine startup or shutdown to prohibiting fire pump testing during the same hour as a startup or shutdown. (The FDOC did not include a discussion of the fire pump modeling required by the CEC.)

SCAQMD Permitting Review of Modeling Provided in the Application

First, the permitting engineer reviewed the facility-wide air dispersion modeling analysis in the Application to determine whether the modeled worst-case operating cases and emissions rates reflected actual operations and permitted emission rates. As discussed below under the analysis

for *Rule 1401--New Source Review of Toxic Air Contaminants*, the permitting engineer also reviewed the health risk assessment in the Application to determine whether the HRA demonstrated compliance with Rule 1401 and supported the CEC's CEQA analysis.

One, the SCAQMD requested changes to the proposed worst-case modeling scenarios and emission rates for the air dispersion modeling, clarification on the modeling, and a complete health risk assessment in SCAQMD AI Letter, 5/1/18. Bicent provided responses and revised modeling and health risk assessment analyses in Bicent Response Letter, 5/17/18. Two, the SCAQMD requested clarification on the commissioning and fumigation analyses in SCAQMD AI Letter, 9/26/18. Bicent provided responses and revised modeling for the commissioning in Bicent Response Letter, 10/20/18. Three, the SCAQMD requested clarification in an e-mail, dated 1/9/18, regarding why the commissioning analysis emissions increased from the May submittal to the October submittal but the maximum concentration decreased. Bicent Response Letter, 1/23/19, provided clarification and confirmed the commissioning modeling provided in Bicent Response Letter, 10/20/18 was correct.

SCAQMD Modeling Review of Revised Modeling

Second, the air dispersion modeling and health risk assessment, as revised by the applicant pursuant to the permitting engineer's review, were forwarded to Engineering & Permitting Dept (E&P) modeler Sam Wang for review of the modeling mechanics. The modeling review request memo (initial and Rev. 1) from the permitting engineer set forth the purpose of the memo; facility description; application objectives; prior applications and modeling performed; discussion of models for dispersion modeling and fumigation impacts, meteorological data, background data, and NOx to NO_2 conversion described in the Application; and discussion of modeling performed for the Application and modeling revisions and clarifications submitted in Bicent Response Letters, dated 5/17/18, 10/20/18 and 1/23/19.

Pursuant to SCAQMD procedure, Modeler Sam Wang began reviewing the applicant's revised modeling submittal by independently reproducing the dispersion modeling analysis for Rules 1303 and 2005, and the health risk assessment for Rule 1401. The purposes are to verify compliance with SCAQMD rule requirements and also to support CEC's CEQA analysis.

Prior to the completion of the SCAQMD Modeler's review, Bicent filed the *Petition to Amend for Site Delineation* to further amend the CEC Decision for the MGS on 2/4/19, as discussed above. The petition requested modification of the site boundary to reflect that Bicent does not control certain portions within the current site boundary and ancillary facilities, which are still owned and operated by the City of Vernon. These areas include the natural gas pipeline, the landscaping area outside the boundary of the MGS, and Station A, a designated historical resource. The modeling submitted in the Application was based on receptors placed along and extending from the current MGS site boundary. The petitioned modification would move the fence line to exclude an area that had been within

the current MGS site boundary but is actually City of Vernon property. Therefore, receptors would need to be added to the City of Vernon property, as it will become exterior to the modified MGS site boundary.

On 2/27/19, SCAQMD staff held a conference call with Bicent staff and consultants to discuss the SCAQMD's preliminary review of the Applicant's modeling analyses. The applicant used meteorological data from the SCAQMD's Compton Station for the years of 2012, 2015, and 2016. Three years of MET data were available from the Compton station, instead of the required five years of data. The SCAQMD requested revised modeling for the project based on SCAQMD's Downtown LA/USC Station for the years of 2012, 2013, 2014, 2015 and 2016. The Downtown LA/USC Station is closer to the MGS, and the required five years of data are available. In addition, the SCAQMD requested that the modeling be revised to include additional receptors on the City of Vernon property because of the petitioned change in fence line.

As a follow-up to the conference call, Modeler Sam Wang sent the following e-mail, dated 3/5/18, to Consultant Gregory Darvin:

> Here is a summary of my modeling recommendations made during our conference call on 2/27/2019. Please let us know if there are any questions or concerns.
>
> - SCAQMD recommends MGS to re-submit the modeling (both criteria pollutants and HRA) files for review due to the property boundary (fenceline) change recently. This change is based on the information in "Malburg Generating Station Petition to Amend For Site Delineation" that MGS submitted to CEC on 2/4/2019 (TN#22640).
> - SCAQMD indicated that it is EPA, CARB/OEHHA, and SCAQMD's policy that requires all proposed projects to use five years of meteorological data from the most representative meteorological station to model their air quality impacts (criteria pollutants and TACs) (see footnotes 1,2,3). However, for this specific project, MGS would like to find the justification and buy off from EPA that using three years meteorological data set from a NWS/ASOS station is sufficient, since five years of data is not available at the selected meteorological station. MGS agreed to send the above justifications to SCAQMD along with the revised modeling files (for both criteria pollutants and HRA) for review.
> - Gregory Darvin will call Sam Wang (SCAQMD) to discuss other minor modeling comments that District has before Greg start re-modeling.
> - The revised modeling files will include the additional receptors due to change in fence line.

Note 1:
EPA Appendix W, 2017 (https://www3.epa.gov/ttn/scram/appendix_w/2016/AppendixW_2017.pdf). "(page 5223) *The model user should acquire enough meteorological data to ensure that worst-case meteorological conditions are adequately represented in the model results. The use of 5 years of adequately representative NWS or comparable meteorological data, at least 1 year of site-specific, or at least 3 years of prognostic meteorological data, are required.*"

Note 2:
CARB/OEHHA (https://www.arb.ca.gov/toxics/harp/harp.htm)

Note 3:
SCAQMD modeling guidance (http://www.aqmd.gov/home/air-quality/air-quality-data-studies/meteorological-data/modeling-guidance), "*… Modeling for criteria pollutants and HRA's should use the most recently available and meteorologically-appropriate 5-year data set, as is required for AERMOD applications by U.S. EPA's Appendix W*"

Thereafter, Mr. Darvin informed Sam Wang that he had called his EPA contact after the conference call on 2/27/19 to request confirmation that three years of a meteorological data set from his selected station (Compton Station) was sufficient, because five years of data is not available. EPA responded that they could not comment on the validity of using three years of MET data until after their review of the completed modeling analysis.

In a letter dated March 8, 2019, Mr. Darvin provided responses to the District's comments on the modeling analyses. The letter is posted on the CEC website on 3/14/19 (TN # 227331).

- ***Compton Meteorological Data***
  SCAQMD had requested that the Applicant re-model the air quality analysis and HRA for the project based on the Downtown LA/USC Station for which 5-years of MET data was available.

  Mr. Darvin responded that, while they do not disagree that the use of the 5-years of Downtown LA/USC data would satisfy the Appendix W requirements, the use of the 3-year Compton meteorological data set would still satisfy the Appendix W requirements.

  The response from Mr. Darvin's letter is reproduced below:

  > The MGS modeling analysis utilized three years of meteorological data from the Compton monitoring site with the technical justification summarized in the October 2017 Modeling Protocol which was submitted to the SCAQMD and the CEC. While EPA Appendix W (Guidelines on Air Quality Models) recommends up to

five (5) years of National Weather Service (NWS) data (subsection 8.3.1.2), it allows for at least one (1) year of on-site representative data in order to determine the design concentration for the receptor utilized in the modeling assessment. While the Appendix W Guidelines are focused on the preparation of PSD modeling assessments, the Guidelines do allow for flexibility in determining the appropriate meteorological data base to be used in dispersion modeling assessments. Specifically, Appendix W allows for *"Procedures with respect to the review and analysis of air quality modeling and data analyses in support of SIP revisions, PSD permitting, or other regulatory requirements need a certain amount of standardization to ensure consistency in the depth and comprehensiveness of both the review and the analysis itself. This section recommends procedures that permit some degree of standardization while at the same time allowing the flexibility needed to assure the technically best analysis for each regulatory application."* (Appendix W Section 10.0 Regulatory Application of Models).

The use of the Compton meteorology was deemed to be the most representative data during the development of the modeling protocol. While the USC data became available after the permit application submittal, analyzing the surface characteristics of the area surrounding the data collection site and comparing it with Table 2 of the MGS Modeling Protocol still demonstrates that the land use characteristics at the Compton site more closely matches the land uses and types around the MGS project site.

The modeling guidelines also clarify that the probabilistic form of the 1-hour NO_2 standard is based on the modeled 3-year average of the 98th percentile of the annual distribution of the daily maximum concentrations. As noted in the EPA Clarification Memorandum *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard* (March 2011) "The June 29, 2010 memo addressed one aspect of the applicability of ambient monitoring requirements, set forth in Appendix S to 40 CFR Part 50 in relation to the 1-hour NO_2 standard, to modeling applications to demonstrate compliance with the NAAQS, namely the use of 3 years of ambient monitoring data as the basis for attainment of the NAAQS using monitoring vs. the use of 5 years of meteorological data for modeling demonstrations of compliance with the NAAQS. Specifically, the June 29, 2010 memo indicated that "*Although the monitored design value for the 1-hour NO_2 standard is defined in terms of the 3-year average, this definition does not preempt or alter the Appendix W requirement for use of 5 years of NWS meteorological data or at least 1 year of site specific data.*

The 5-year average based on use of NWS data, or an average across one or more years of available site- specific data, serves as an unbiased estimate of the 3-year average for purposes of modeling demonstrations of compliance with the NAAQS. Modeling of 'rolling 3-year averages,' using years 1 through 3, years 2 through 4, and years 3 through 5, is not required." While we do not disagree that the use of 5-years of USC data would satisfy the Appendix W requirements, the use of the 3- year Compton meteorological data set also allows for the calculation of the 3-year average for purposes of determining the probabilistic form of the NO_2 NAAQS and would still satisfy the Appendix W requirements.

It is also important to mention that the EPA defines the term "site specific data" to mean data that would be representative of atmospheric dispersion conditions at the source and at locations where the source may have a significant impact on air quality. Specifically, the meteorological data requirement originates from the Clean Air Act in Section 165(e)(1), which requires an analysis "of the ambient air quality at the facility and in areas which may be affected by emissions from such facility for each pollutant subject to regulation under [the Act] which will be emitted from such facility." This requirement and EPA's guidance on the use of on-site monitoring data are also outlined in the "*On-Site Meteorological Program Guidance for Regulatory Modeling Applications (USEPA, 2000)."* The representativeness of meteorological data is dependent upon: the proximity of the meteorological monitoring site to the area under consideration; (b) the complexity of the topography of the area; (c) the exposure of the meteorological sensors; and (d) the period of time during which the data are collected.

The use of the 3-year Compton meteorological data set, based on both regional wind field flow characteristics and the surrounding land use classifications would also satisfy the definition of site-specific data and would therefore be considered to be the most meteorologically representative data set to use for modeling the dispersion characteristics in the region surrounding the MGS project site.

We would also note that on the SCAQMD web site (http://www.aqmd.gov/home/air-quality/air-quality-data-studies/meteorological-data/aermod-table-1) which lists the available data for use in preparing modeling assessments (AERMOD Table 1) that the 3-year Compton data set is available for regulatory application with the proper justification. The technical justification was provided in the MGS Modeling Protocol as the most representative data set available at that time of the modeling submittal.

" The Compton (CMPT) station is not available for download as the station does not have 5 years of data that meets quality assurance procedures. However, in special cases where it can be demonstrated that there are no other meteorologically-representative stations within the Basin for the modeled source(s), 3 years of processed data (2012, 2015, and 2016) are available upon request and approval of use. Technical justification will need to be provided within the modeling report on why this station was considered more appropriate than other stations."

In summary, and in keeping with the regulatory flexibility allowed under Appendix W, the use of the 3-year Compton meteorological data set would assure that the following occurs:

- The technically best analysis for this regulatory application has been used
- The Compton data set satisfies the use of site-specific data
- The 3-year length of record satisfies the calculation methodology of the 1-hour probabilistic form of the NO_2 standard.

*****SCAQMD Follow-up**

Due to time constraints, SCAQMD Modeler Sam Wang re-modeled the air quality analysis and HRA for the project based on 5-years of Downtown LA/USC data.

- ***Background Air Quality Data***

SCAQMD had requested that the Applicant confirm the background concentrations that were used in its modeling and update the background concentrations to include 2017.

Mr. Darvin provided a correction for maximum 4^{th} high daily maximum 8-hour ozone concentration but indicated the other background concentrations were correct. Mr. Darvin did not update the background concentration to include 2017.

The response from Mr. Darvin's letter is reproduced below:

We have reviewed the background air quality data, specifically the 3-year averages of the concentrations used for the National Ambient Air Quality Standards (NAAQS). We have confirmed that the 3-year averages of the 98^{th} percentile daily 1-hour NO_2 daily maxima, the 99^{th} percentile daily 1-hour SO_2 daily maxima, the 98^{th} percentile 24-hour PM2.5 concentrations, and the annual PM2.5 concentrations are correct on Table 6 of the original application. However, the maximum 4^{th} high daily maximum 8-hour ozone concentration of 143 $\mu g/m^3$ was

shown instead of the 3-year average of 132 µg/m^3. A corrected Table 6 is attached at the end of this response.

*****SCAQMD Follow-up**

Due to time constraints, SCAQMD Modeler Sam Wang corrected and updated the background concentrations in conjunction with his re-modeling of the air quality analysis and HRA for the project.

- ***Additional Receptors/Impacts for City of Vernon Property***

SCAQMD had requested that the Applicant re-model the air quality analysis and HRA for the project to add receptors to the City of Vernon property. Because of the petitioned change in fence line, the City of Vernon property would become exterior to the current MGS site boundary.

Mr. Darvin performed an air quality analysis of the City of Vernon property only. Since all of the modeled concentrations for the City of Vernon property are less than the prior maximum impacts (referring to *Table 30 - Modeled Results -Normal Operations Impact Analysis – Total Facility (A/N 598922 & 598923—Turbine Upgrade* below), Mr. Darvin concluded that no updates to prior modeling analyses are required. Mr. Darvin took the same approach with the HRA. His comparison for the air quality analysis is set forth below in his **Comparison of Impacts for Additional Receptors for City of Vernon Property** table below**.** His comparison for the HRA is set forth in his Table 2 Worker Results from ADMRT 19044 ***table below.***

The response from Mr. Darvin's letter is reproduced below:

Additional 20-meter spaced receptors covering the City of Vernon property located on the same block as the project site were analyzed with the same meteorology and methodology as followed in the application and comment responses. Also, 10-meter spaced receptors along the property boundary between the project site and the City of Vernon property were analyzed. These receptors are shown in the attached Figure 1. All of the modeled concentrations for the City of Vernon property are less than the prior maximum impacts as shown on the attached table. Therefore, no updates to prior modeling analyses are required.

Comparison of Impacts for Additional Receptors for City of Vernon Property

Pollutant	Averaging Period	Prior Maximum Concentrations (µg/m³)	City of Vernon Property Maximum Concentrations (µg/m³)
Normal Operating Conditions			
NO_2*	1-hour maximum (CAAQS)	126.6	52.7
	3-year average of daily 1-hour yearly maxima (NAAQS) [a]	4.46	3.29
	3-year average of 1-hour yearly 98th% (NAAQS)	3.48	2.53
	Annual maximum (CAAQS/NAAQS)	0.50	0.24
CO	1-hour maximum (NAAQS/CAAQS)	33.0	5.9
	8-hour maximum (NAAQS/CAAQS)	1.9	0.8
SO_2	1-hour maximum (CAAQS)	0.42	0.14
	3-year average of daily 1-hour yearly maxima (NAAQS) [a]	0.15	0.12
	3-year average of 1-hour yearly 99th% (NAAQS)	0.14	0.10
	3-hour maximum (NAAQS)	0.15	0.08
	24-hour maximum (CAAQS/NAAQS)	0.04	0.02
	Annual maximum (NAAQS)	0.016	0.007
PM10	24-hour maximum (CAAQS/NAAQS)	0.98	0.41
	24-hour 4th highest over 3 years (NAAQS)	0.86	0.38
	Annual maximum (CAAQS)	0.35	0.15
PM2.5	3-year average of 24-hour yearly maxima (NAAQS) [a]	0.86	0.39
	3-year average of 24-hour yearly 98th % (NAAQS)	0.70	0.31
	Annual maximum (CAAQS)	0.35	0.15
	3-year average of annual concentrations (NAAQS) [a]	0.31	0.14
Cold Start-up Periods			
NO_2*	1-hour maximum (CAAQS)	85.58	82.45
	3-year average of daily 1-hour yearly maxima (NAAQS) [a]	78.59	75.97
	3-year average of 1-hour yearly 98th % (NAAQS)	65.78	57.96
CO	1-hour maximum	143.6	137.9
Non-Cold Start-up Periods			
NO_2*	1-hour maximum (CAAQS)	70.74	69.55
	3-year average of daily 1-hour maxima (NAAQS) [a]	65.15	63.85
	3-year average of 1-hour yearly 98th % (NAAQS)	54.90	48.42
CO	1-hour maximum	82.6	81.2
Start-up/Shutdown Periods			
CO	8-hour maximum	32.1	16.3
Commissioning Activities			
NO_2*	1-hour maximum (CAAQS)	71.69	71.23
CO	1-hour maximum	142.6	141.3
	8-hour maximum	53.1	27.7

*1-hour NO_2 impacts for comparison to CAAQS under Normal Operating Conditions evaluated with the Ozone Limiting Method (OLM). All other NO_2 1-hour and annual impacts evaluated assuming 100% conversion of NOx to NO_2.

*****SCAQMD Follow-up**

Due to time constraints, SCAQMD Modeler Sam Wang re-modeled the air quality analysis and HRA for the project using all near field and far field receptors, including the addition of receptors to the City of Vernon property.

- ***Flagpole Receptors for Health Risk Assessment***

SCAQMD had requested that the Applicant consider the elevation of the receptors added to the City of Vernon property. Mr. Darvin used flagpole heights only for those City of Vernon property receptors.

The response from Mr. Darvin's letter is reproduced below:

A review of all the properties surrounding the project site with Google Earth street view show mostly single-story warehouses and other commercial properties. Therefore, flagpole receptors are not required for most nearby properties. Any nearby multi-storied structures are identified on the attached Figure 1 and were modeled with flagpole receptors at the appropriate heights to update estimates of off-site worker exposures. These structures are listed in Table 1.

Table 1 Flagpole Receptor Locations and Heights

Structure (BPIP ID#)	Description	Flagpole Hts (ft)
City of Vernon (#7A)	60' Power Plant & Offices (equiv. to 3 stories)	5', 25', 45'
Offices (#F)	48' 2-story Offices	5', 29'
Warehouse (#E3)	48' 2-story Warehouse	5', 29'
Offices (#C3)	22' 2-story Offices	5', 16'

These receptors were assessed with the Air Dispersion Modeling and Risk Tool (ADMRT) to develop new worker risk values for the additional receptors in order to characterize the risks from the MGS facility. Based on the locations of the receptors on the City of Vernon property, only worker exposures were calculated. The overall maximum facility risk of 3.97 in a million from the previous

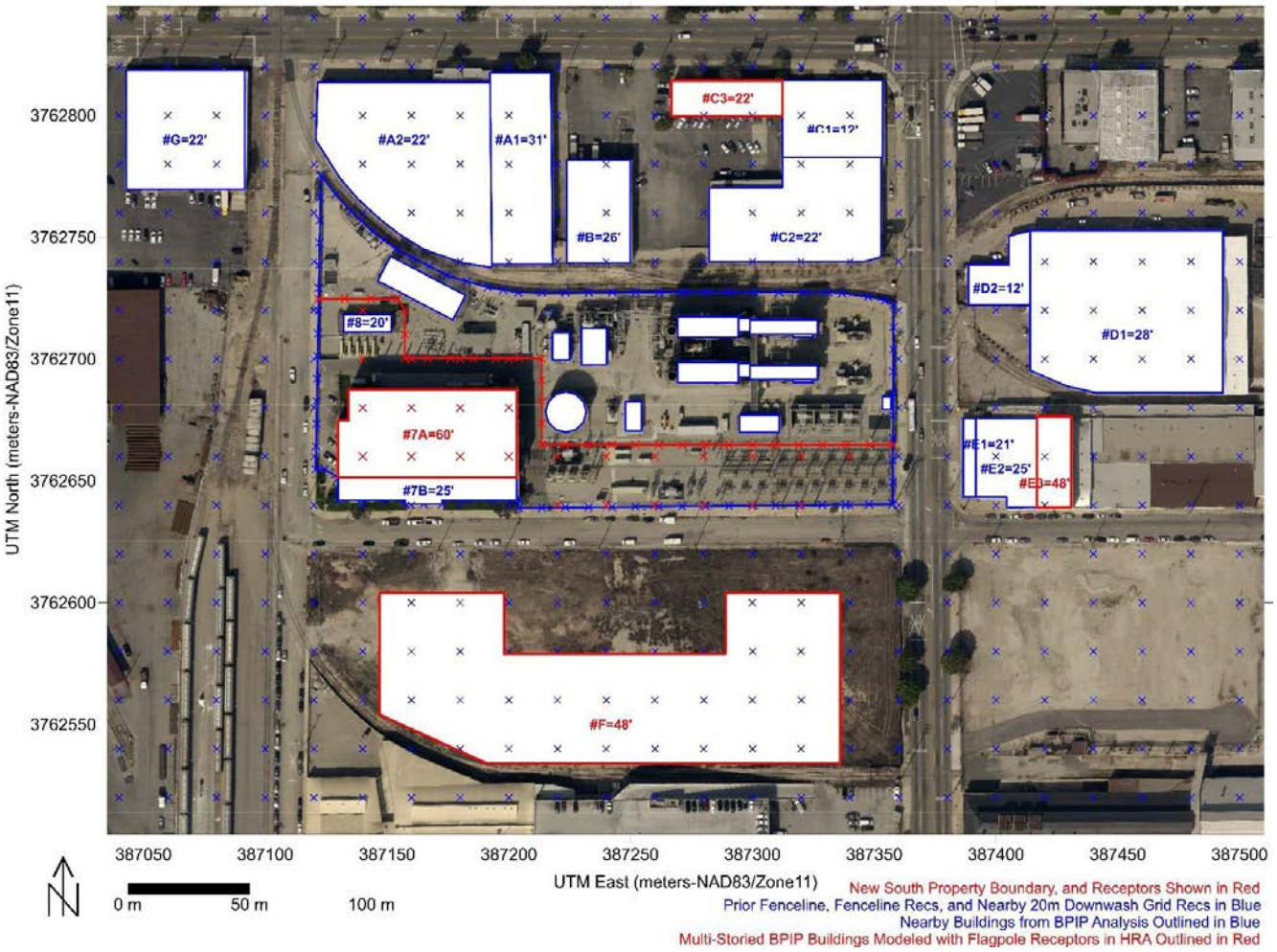
assessments is still maintained as the new risk values summarized in Table 2 are significantly less than the reported.

Table 2 Worker Results from ADMRT 19044

Scenario	MIR Receptor #	Cancer Risk	Chronic HI at MIR	Acute HI at MIR
2019 Total Facility Values	2612	3.97 E-6	0.00476	0.00524
3/2019 Worker Max Cancer and Chronic Receptor	136	2.03 E-7	0.00354	0.00615
3/2019 Worker Max Acute Receptor	75	5.98E-8	0.00212	0.00633

The January 2019 results are based on the same emissions and plot files as the May 2018 analysis. The total facility values include the turbines, cooling tower, and fire-pump.
Additional worker receptors added in March 2019 at request of SCAQMD. Results based on total facility emissions and include flagpole receptors.
The latest version of HARP (ADMRT 18159) was used versus the earlier version ADMRT 17320 which was valid for the approximate period 1-7-17 through 6-13-18. Version 19044 was used for the 3/2019 worker evaluation.

Figure 1
Additional Receptors and Flagpole Receptor Locations



*****SCAQMD Follow-up**

Due to time constraints, SCAQMD Modeler Sam Wang re-modeled the air quality analysis and HRA for the project using all near field and far field receptors, including using the adjusted elevation of the receptors added to the City of Vernon property and the adjusted elevation of other near field receptors.

♦♦

ENGINEERING & PERMITTING MODELING REVIEW MEMO, DATED 3/22/19, FROM MODELER SAM WANG

The modeling review memo, dated 3/22/19, from Modeler Sam Wang to Supervising Engineer Bhaskar Chandan provided comments on the applicant's analyses. The memo also included a discussion of and the results for his re-modeling of the air quality analysis and risk assessment for this project. The modeling review memo contents are incorporated in the evaluation below as appropriate.

A copy of this modeling review memo is included in this evaluation in **APPENDIX— ENGINEERING & PERMITTING (E&P) MODELING REVIEW MEMO, DATED 3/22/19.**

The modeling review memo found the following issues with the modeling files submitted by Bicent, prior to their most recent submittal on 3/8/19.

- Inadequate meteorological data and selection of the most representative meteorological station
- Outdated and incorrect background air quality monitoring data and selection of the most representative air quality monitoring stations
- some model results do not include the impacts for individual sources
  some near field receptors have incorrect elevations and no receptors on the southern portion of the project site (files dated 11/27/2018). On 2/27/2109, SCAQMD required MGS to re-submit the modeling (both criteria pollutants and HRA) files for review due to the property boundary (fenceline) change recently. This change is based on the information in "Malburg Generating Station Petition to Amend For Site Delineation" that MGS submitted to CEC on 2/4/2019 (TN#22640).

Due to time constraints, SCAQMD Modeler Sam Wang re-ran the AERMOD and HRA using the correct meteorological data, ozone data, receptors, control pathways, source groups, background air quality monitoring data for all operating scenarios.

The major differences between the applicant's modeling files with SCAQMD's modeling files are summarized in the table below. A detailed description to explain the differences are provided in Attachment A of the modeling review memo.

Table 26A-- Major Differences Between Applicant's Modeling Files and SCAQMD's Modeling Files

	Applicant	SCAQMD
Meteorological Data and Station	3 years (2012, 2015, and 2016) meteorological data from SCAQMD's Compton Station were used. Compton Station is located 6 mile south of the project site.	5 years (2012, 2013, 2014, 2015, and 2016) meteorological data from SCAQMD's Downtown LA/USC Station were used. Downtown LA/USC Station is located 4 mile north-northwest of the project site and has been determined to be the most representative meteorological station to use for this project analyses.
Ozone Data and Station	3 years (2012, 2015, and 2016) ozone data from SCAQMD's Compton Station were used.	5 years (2012, 2013, 2014, 2015, and 2016) ozone data from SCAQMD's Compton Station were used.
Background Air Quality Monitoring Data	3 years (2014, 2015, and 2016) background air quality monitoring data were obtained from Compton, LA-N. Main Street, and Pico Rivera #2 stations from SCAQMD and EPA AIRS database.	The most recent 3 years (2015, 2016, and 2017) background air quality monitoring data were obtained from Compton and LA-N. Main Street stations from SCAQMD monitoring data. Pico Rivera #2 station is downwind to the project site and has different wind patterns than the project site. Therefore this station should be excluded. SCAQMD's monitoring data is more reliable and should be used in the analysis.
Receptors	The original modeling files have near field receptors (20 meter spacing) with fenceline grids and far field receptors (100 meter spacing). The 2019 revised modeling files have only 58 additional receptors placed on the southern side of the project site due to the fenceline change (Petition to Amend for Site Delineation, CEC, 2/4/2019).	All modeling files include fenceline grids, near and far field receptors using the new site layout boundary due to the fenceline change (including about 100 additional receptors on the south side of project). The heights were adjusted for the near field receptors placed on the top of buildings.
Screening model	Screening modeling for the turbine was performed.	Screening modeling for the turbine was re-run based on the new model settings (meteorological data, ozone data, receptors, and etc.). The results show Scenario 14 has the worst impacts for all pollutants in all averaging time.
Operation (normal, startup, commissioning)	AERMOD modeling was performed. The model results have the total impacts from the entire facility as well as the total impacts from the two turbines combined.	AERMOD modeling was re-run using the new model settings and the parameters from new screening results. In addition to the total impacts from the entire facility and total impacts from the two turbines combined, the model

		results also provide the impacts from each turbine and each stationary source.
Fumigation	AERSCREEN modeling was performed.	Modeling is acceptable - no comment on the applicant's files
HRA	Tier 4 HRA was performed.	Tier 4 HRA was re-run using the new model settings and the parameters from new screening results.

SCAQMD Modeling Review Memo Conclusion: The SCAQMD's modeling results for Air Quality (AQ) and HRA impacts from the entire project are all under the applicable thresholds in Rule 1303, Rule 1401, and Rule 2005 for all criteria pollutants and air toxics. Therefore, the AQ impacts from the MGS are considered in compliance with National Ambient Air Quality Standards (NAAQS), California Ambient Air Quality Standards (CAAQS), and SCAQMD's modeling and HRA requirements.

♦♦

The following discusses the modeling provided by Bicent, prior to their most recent submittal on 3/8/19.

I. Protocol, Models for Dispersion Modeling and Fumigation Impacts, Meteorological Data, Background Data, and NOx to NO_2 Conversion

The *Air Quality Modeling Protocol, Malburg Generating Station, October 2017*, is included in *Attachment 6—Air Quality Impact Analysis Data* of the Application.

P. 1-28 of the Application indicates the applicant utilized AERMOD (version 16216r) for the air dispersion modeling and AERSCREEN (version 16216) for the inversion-breakup fumigation impacts. P. 1-31 states the Compton meteorological monitoring site was selected as the most representative meteorological data set, and three years of recent data (2012, 2015, and 2016) were used for this project.

From p. 1-16, the nearest criteria pollutant air quality monitoring sites to the proposed project site would be the stations located in Compton, Pico Rivera, and LA-North Main for the period 2014 through 2016. Ambient monitoring data for these sites for the most recent three-year period is summarized in *Table 5—Measured Ambient Air Quality Concentrations by Year*, p. 1-16. On p. 1-18, *Table 6—Background Air Quality Data* shows the background air quality values based upon the data presented in *Table 5*. The background values represent the highest values reported for the site during any single year of the most recent three-year period. P. 6 of the *Protocol* clarifies the Compton measurements were used for representative background

concentrations when available, because of the similar land use characteristics of the Compton monitoring and MGS project site. The Pico Rivera #2 data was deemed less representative of MGS baseline air quality, but were included for comparison to the other two sites. Further, as neither the Compton nor Pico Rivera #2 monitoring sites measure PM_{10} or SO_2, such data were taken from LA-North Main.

From p. 1-36, the footnote to *Table 18—Air Quality Impact Results—Ambient Air Quality Standards* indicates the 1-hour NO_2 impacts for comparison to the CAAQS under Normal Operating Conditions were evaluated with the Ozone Limiting Method (OLM) for CAAQS. All other NO_2 1-hour and annual impacts were evaluated assuming 100% conversion of NOx to NO_2. From p. 1-34, the in-stack ratio of NO_2/NOx was set to 0.5 for the turbines/HRSG's and 0.2 for the fire pump (fire pump ratio based on ISR database), following EPA and SCAQMD guidance for OLM.

SCAQMD Modeling Review Memo: Bicent selected the appropriate air quality models.

II. Normal Operations Impact Analysis

As discussed on pp. 1-32 to 1-37, the Application divided the normal operations impact analysis into two analyses: (1) normal operating conditions analysis, and (2) startup and shutdown analysis.

The SCAQMD reviewed the modeling scenarios and emission rates set forth in the *Table 16--Worst-Case Stack Parameters and Emission Rates* on p. 1-33, *Table 18—Air Quality Impact Results—Ambient Air Quality Standards* on p. 1-36, and the *Malburg Generating Station Emission Rates and Stack Parameters for Refined Modeling* table in *Attachment 6*.

As discussed below, Bicent Response Letter, 5/17/18, provides revised *Table 16*, revised *Table 18—Air Quality Impact Results—Ambient Air Quality Standards,* and revised *MGS Emission Rates and Stack Parameters for Refined Modeling* table in *Attachment 6*, in response to the SCAQMD's requested changes set forth in SCAQMD AI Letter, 5/1/18.

1. NORMAL OPERATING CONDITIONS ANALYSIS

The first analysis is the normal operating conditions analysis for the facility consisting of two combined-cycle turbines, emergency engine for the fire pump, and cooling tower (3 cells). For this analysis, the turbine modeling does not include any startup or shutdown events, with the exception of the annual averaging period.

a. Combined-Cycle Gas Turbines (Two)

For the Normal Operations Impact Analysis, the information provided in the Application is summarized first, followed by a summary of the modeling revised in response to SCAQMD AI Letter, 5/1/18.

- **Application**

  Pursuant to p. 1-32 of the Application, the operational characteristics of a turbine, such as emission rate, exit velocity, and exit temperature vary by operating load and ambient temperature. Therefore, a screening modeling analysis, using AERMOD, was performed for the sixteen operating scenarios (Cases S1 – S16) to determine the turbine operating condition that will result in the highest modeled concentrations for each averaging period. The analysis was performed on three load scenarios (60%, 80%, and 100%), with and without evaporative cooling, with and without duct burner on, and for four ambient temperature conditions: 38 °F (a cold day), 59 °F (ISO conditions), 65 °F (annual average day), and 94 °F (hot day).

  The combustion turbine operating condition that resulted in the highest modeled concentration in the screening analysis for each pollutant and averaging time was identified as the worst-case impact. The results of the screening analysis are listed in *Attachment 6* in the *Malburg Generating Station AERMOD Turbine Screening Results* table. The screening analysis showed that the worst-case operating and ambient conditions resulting in the maximum predicted concentrations was Case S14 (100% load, 59 ºF, duct burner on) for all short-term impacts, and Case S15 (100% load, 65 ºF, duct burner on) for annual impacts, as reflected in *Table 16—Worst-Case Stack Parameters and Emission Rates* on p. 1-33.

  Bicent Response Letter, 5/17/18, items 8.a.i.aa and 8.a.i.bb.1 provided clarification regarding the selection of Cases for maximum impacts and modeled emissions rates. For short-term impacts, the AERMOD screening analysis shows that Case S14 has the overall maximum 1-hour impacts for NOx (state and federal 1-hour), CO, and SO_2 (state and federal 1-hour), as well as maximum short-term impacts for other averaging times and pollutants. Accordingly, the stack parameters and modeled emission rates are based on Case S14 (100% load, 59 ºF ambient, duct burner on). For annual impacts, the stack parameters are typically based on 100% load at annual average conditions (65 ºF), duct burner on, which corresponds to Case S15 (100% load, 65 ºF ambient). However, the annual emission rates are usually calculated on a conservative basis as the worst-case 1-hour emission rate for normal operations which corresponds to Case S13 (100% load, 38 °F ambient, duct burner on).

On p. 1-33, *Table 16—Worst-Case Stack Parameters and Emission Rates* provides the worst-case modeling input for each pollutant and averaging period based on the screening analysis results for the (1) normal operating conditions, and (2) turbine start-ups and shutdowns. For each averaging period, the table provides the equipment modeled and the associated stack height, temperature, and diameter; exit velocity, and emission rates for NOx, SO_2, CO and $PM_{10}/PM_{2.5}$ as appropriate. The assumptions for the derivation of the emission rates are provided in *Attachment 6* in the *Malburg Generating Station Emission Rates and Stack Parameters for Refined Modeling* table. P. 1-32 states the screening analysis results were also used as the refined analysis results.

- **SCAQMD Requested Revision**
  PM_{10} Emission Rate for 24-Hour Averaging
  SCAQMD AI Letter, 5/1/18, item 8.b.i.aa stated that, on p. 1-33 of the Application, *Table 16—Worst-Case Stack Parameters and Emission Rates* indicates the PM_{10} modeling for the 24-hour averaging period was based on 0.4207 g/sec (3.339 lb/hr) PM_{10}. Footnote b states: "PM10/PM2.5 emissions based on permit limit of 29.25 tons/year total for both turbines." The footnote is referring to the condition A63.3 limit of 4876 lbs in any one month for the two turbines. However, the 4876 lbs was based on Vernon City, Light & Power Dept.'s request to provide 81 lb/day of PM_{10} ERCs, not on the maximum emission rate for PM_{10} of 3.89 lb/hr (Scenario S13). Bicent was requested to revise the PM_{10} modeling for the 24-hour averaging period to be based on 3.89 lb/hr or a lower emission rate if guaranteed by Siemens. For the annual averaging period, the 29.25 tons/yr basis is correct.

  Bicent Response Letter, 5/17/18, item 8.b.i.aa.1 responded that the modeling for the 24-hour averaging period was revised to reflect the new maximum PM_{10} emission rate of 3.386 lb/hr for the 24-hour averaging period. As discussed above, the SCAQMD will accept the proposed 3.386 lb/hr for post turbine upgrade based on recent source tests at the MGS and information provided by Montrose Air Quality Services and Siemens. *Tables 16* and *18* and *Malburg Generating Station Emission Rates and Stack Parameters for Refined Modeling* table in *Attachment 6* were revised accordingly.

b. Fire Pump

- **Application**

  In *Attachment 6*, the *Malburg Generating Station Emission Rates and Stack Parameters for Refined Modeling* table shows that the fire pump emergency engine emissions for NOx, SO_2, CO, and $PM_{10}/PM_{2.5}$ were based on testing for 1 hour for the 1-hour (CAAQS), 3-hour, 8-hour, and 24-hour averaging periods.

  For the federal 1-hr NO_2 and SO_2 averaging periods, footnote a to *Table 16—Worst-Case Stack Parameters and Emission Rates* on p. 1-33 states: "1-hour NO_2 and SO_2 NAAQS assessment based on annual average emissions per USEPA guidance for intermittent sources." As the emergency engine is exempt from modeling requirements per Rule 1304(a)(4) and the modeling was performed for CEQA analysis purposes, the CEC was consulted in an e-mail, dated 1/16/18, regarding the acceptability of using annual average emissions for NO_2 and SO_2. On 1/19/18, CEC provided guidance that the source is the EPA Guidance Document, *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard*, dated 3/1/2011, and noted that the guidance is frequently used. Thus the use of the annual average emissions is acceptable.

- **SCAQMD Requested Revision**

  Number of Operating Hours for Annual Modeling

  The Application provided air dispersion modeling and an HRA for the fire pump. The air dispersion modeling was based on 52 hours but the HRA was based on 199 hours. On 1/16/18, the SCAQMD e-mailed CEC regarding requirements for the emergency engine modeling and HRA, including whether the 52 hours for the modeling and 199 hours for the HRA are correct. Consequently, the CEC asked the consultant, Greg Darvin, to check on whether the different schedules were consistent with the original modeling and HRA. On 1/19/18, Mr. Darvin e-mailed that, as the original modeling and HRA were both based on 199 hours, he would revise the air quality modeling for the fire pump to be based on 199 hours. The SCAQMD responded that the 199 hours should be increased to the currently allowed 200 hours, as set forth in condition C1.5, and would send an additional information letter including this issue.

  SCAQMD AI Letter, 5/1/18, item 8.b.ii.aa, bb, and cc requested revisions to the fire pump modeling. Bicent Response Letter, 5/17/18, item 8.b.ii.aa stated the annual modeling was revised to increase the annual operation of the fire pump to 200 hours. Item 8.b.ii.bb stated that this also included

revising the federal 1-hr NO_2 and SO_2 analysis to be based on the revised annual average emission rate. Item 8.b.ii.c. was in response to the SCAQMD's comment that *Table 16—Worst-Case Stack Parameters and Emission Rates* shows fire pump emission rates that are reflective of the hourly emission rates for the fire pump, device D48, permitted under A/N 482576, on the facility permit. In *Attachment 6*, the *MGS Emission Rates and Stack Parameters for Refined Modeling* table, however, shows fire pump emission rates that are reflective of one-half of the hourly emission rates for the fire pump, device D46, permitted under A/N 403104 in the FDOC, but never installed. In addition, *Table 16* reflected the revised PM_{10} rate of 7.27 lb/day for the cooling tower that will become effective after the turbine upgrade, but the *Attachment 6* table still reflected the original 6.24 lb/day, effective prior to the turbine upgrade. *Tables 16* and *18* and *Malburg Generating Station Emission Rates and Stack Parameters for Refined Modeling* table in *Attachment 6* were revised to address the SCAQMD's requested revisions.

c. <u>Cooling Tower</u>

The three-cell cooling tower is modeled as three separate point sources. The Application had indicated the PM_{10} emission rate for the cooling tower will increase from 6.2 lb/day to 7.3 lb/day for the turbine upgrade project. Bicent Response Letter, 10/20/18, item 6.b.iii. acknowledged the water analysis indicated the Total Dissolved Solids of the cooling tower water was 1020 mg/liter, not the 1125 mg/l used to calculate the 7.3 lb/day. Based on the correct 1020 mg/liter, the PM_{10} limit should be increased to 6.6 lb/day. Since the modeling for the Application was based on 7.3 lb/day, re-modeling is not required to reflect the lower emission rate of 6.6 lb/day.

2. <u>STARTUP AND SHUTDOWN ANALYSIS</u>

The consultant, Greg Darvin, typically provides a separate startup and shutdown analysis, instead of combining normal operating hours and startups and shutdowns for the worst-case scenario for each averaging period. A purpose of this analysis is to support the request in the Petition to revise Condition of Certification AQ-C8, which currently prohibits the testing of the fire pump on a day in which either combustion turbine has had a startup or shutdown. The Petition proposes to modify the restriction to allow testing of the fire pump on the same day as a startup or shutdown event but prohibit the testing during the same hour as a startup (cold and non-cold) or shutdown event.

As with the <u>Normal Operations Impact Analysis</u> above, the information provided in the Application is summarized first, followed by a summary of the modeling revised in response to SCAQMD AI Letter, 5/1/18.

a. <u>Combined-Cycle Gas Turbines (Two)</u>

As discussed on p. 1-37 of the Application, the second analysis is a separate start-up and shutdown analysis for the two turbines for the short-term averaging periods (1-hour and 8-hour), with the fire pump included for the 8-hour averaging period. In addition to incorporating the emission rate changes resulting from the turbine upgrade project, the modeling incorporates the startup and shutdown related emissions changes incorporated into conditions A99.3 and A99.4 by A/N 517249 and 517250 for which a modeling analysis was not provided by the facility. These changes had included significantly higher cold start up emissions for NOx and CO.

The analysis included only NOx and CO emissions because these emissions are higher during start-ups and shutdowns. The $PM_{10}/PM_{2.5}$ and SO_2 emissions are not analyzed because these emissions are expected to be no greater for start-ups and shutdowns than for normal operation at 100% load, which are already covered by the first analysis above. $PM_{10}/PM_{2.5}$ and SO_2 emissions are uncontrolled and proportional to fuel usage.

On p. 1-33, *Table 16—Worst-Case Stack Parameters and Emission Rates* shows that the worst-case operating and ambient conditions resulting in the maximum predicted concentrations for startups and shutdowns is Case S1 (60% load, 38 ºF, duct burner off).

Bicent Response Letter, 5/17/18, item 8.a.i.bb.2)a and 8.a.i.bb.2)b provided clarification regarding the selection of Cases for maximum impacts and modeled emissions rates for the startup and shutdown modeling. The basis for the stack parameters is the worst case minimum load condition from the screening analysis which corresponds to Case S1 at 60% load. Using the worst-case minimum load condition gives a reasonable estimate of the stack parameters averaged over the startup and shutdown periods (going from 0% to 100% loads and then back to 0%). For the 1-hour and 8-hour averaging periods, the startup and shutdown emissions are based on the startup and shutdown limits provided in condition A99.3 for NOx and A99.4 for CO. For the 8-hour averaging period, the normal operating emissions is based on the worst-case 1-hour short-term emissions rate for normal operations, which corresponds to Case S13 (100% load, 38 °F ambient).

1) <u>1-Hour Averaging Period</u>

In *Attachment 6*, the *Malburg Generating Station Emission Rates and Stack Parameters for Refined Modeling* table shows that for the 1-hour averaging period, two modeling scenarios for the startup of the turbines are

provided. As emissions for startups are higher than for shutdowns, shutdowns do not need to be modeled. The fire pump is not included because the Petition proposes to modify the restriction to allow testing of the fire pump on the same day as a startup or shutdown event but prohibit the testing during the same hour as a startup (cold and non-cold) or shutdown event.

A) 1-Hour Averaging: Scenario 1—"One Turbine in Cold Startup"

- **Application**

  In *Table 16—Worst-Case Stack Parameters and Emission Rates* on p. 1-33, this scenario is designated as "Averaging Period: 1-hour for Cold Start-up Periods" for one turbine. In *Table 18—Air Quality Impact Results – Ambient Air Quality Standards* on p. 1-36, this scenario is designated as "Cold Start-up Periods."

  P. 1-37 explains the first scenario is based on one turbine undergoing a cold start and does not include the second turbine. The CO and NOx emissions were modeled for one cold start-up period, assumed to occur over two hours. Conditions A99.3 and A99.4 limit cold starts to 2 hours (without a trip).

- **SCAQMD Requested Revisions**

  i. First Turbine 1st Hour Cold Start

  The Application modeled one turbine undergoing the first hour of a two-hour cold start.

  aa. NOx Emissions First Hour of 2-hr Cold Start

  Condition A99.3 limits NOx emissions for a cold start to 122.8 lbs and 120 minutes. In *Attachment 6*, the *Malburg Generating Station Emission Rates and Stack Parameters for Refined Modeling* table shows the modeled emission rate for NOx for a one-hour averaging period is assumed to be one-half of the 122.8 lbs, which is 61.40 lbs/hr.

  The assumption that the mass emissions for NOx for the first hour of startup is the same as the second hour of startup is not correct. P. 23 of the FDOC explains that during the start-up period, NOx and CO emissions will be higher due to the lack of dry low NOx control in the turbines until a 50% load is reached and the unavailability of control equipment until the proper operating temperatures are reached. P. 41 of the FDOC shows that

the original modeling for start-ups was based on maximum hourly emissions, which take place during the first hour when the catalysts are not warmed up.

P. 23 of the FDOC provides Table 7—Start-up Scenarios Emissions, which summarizes the NOx, CO, and VOC emissions data provided by Alstom for cold starts, warm starts, and hot starts. An excerpt from Table 7 is reproduced below to provide data on the percentage of NOx and CO emissions emitted in the first hour of a cold startup.

Table 27 - Start-up Emissions in 30-Minute Increments for Scenario S13 (A/N 394164 & 394165-FDOC)

Time Period, Minutes	Fuel Use, scf/period	NOx, lbs/period	CO, lbs/period
0 – 30	68,100	10.65	17.35
30 – 60	94,500	2.45	6.95
60 – 90	199,000	1.50	0.10
90 - 120	235,000	1.15	0.10
2 hr. cold start	**596,600**	**15.75**	**24.5**

The cold start emissions for NOx was increased from 15.75 lb/cold start (FDOC) to 122.8 lb/cold start under A/N 517249 and 517250—Startup & Shutdown Revisions, which are the current permits for the two turbines. The increase was required because of actual CEMS data.

The first hour of emissions for the 122.8 lb per cold start is estimated below.

(10.65 + 2.45)/15.75 x 122.8 lb = 102.14 lb

Bicent Response Letter, 5/17/18, item 8.c.i.aa indicated the cold startup modeling has been revised to increase the modeled emission rate for NOx for a one-hour averaging period from 61.40 lbs/hr to 102.14 lb/hr.

bb. ***CO Emissions First Hour of 2-hr Cold Start***

Condition A99.4 limits CO emissions for a cold start to 204.8 lbs and 120 minutes. In *Attachment 6*, the *Malburg Generating Station Emission Rates and Stack Parameters*

for Refined Modeling table shows the modeled emission rate for CO for a one-hour averaging period is assumed to be one-half of the 204.8 lbs, which is 102.4 lbs/hr. As discussed above, the assumption that the mass emissions for CO for the first hour of startup is the same as the second hour of startup is not correct.

The cold start emissions for CO was increased from 24.5 lb/cold start (FDOC) to 204.8 lb/cold start under application nos. 517249 and 517250, which are the current permits for the two turbines. The increase was required because of actual CEMS data.

The first hour of emissions for the 204.8 lb per cold start is estimated below.

(17.35 + 6.95)/24.5 * 204.8 lb = 203.13 lb

Bicent Response Letter, 5/17/18, item 8.c.i.bb indicated the cold startup modeling has been revised to increase the modeled emission rate for CO for a one-hour averaging period from 102.4 lbs/hr to 203.13 lb/hr.

ii. <u>Second Turbine Operating Simultaneously</u>

SCAQMD AI Letter, 5/1/18, item 8.c.i.cc requested that the modeling be revised to add the simultaneous operation of the second turbine based on worst-case emissions for one hour.

aa. <u>NOx Emissions</u>

Bicent Response Letter, 5/17/18, item 8.c.i.cc explained that the facility is designed so that only one turbine can be in cold start mode for the first hour. The NOx modeling has been revised to reflect one turbine in the first hour of a cold start (102.14 lb/hr) with the second turbine in the second hour of a cold start at 20.66 lb/hr.

122.8 lb/cold start - 102.14 lb (first turbine, 1st hr) = 20.66 lb/hr (2nd turbine, 2nd hr)

The 20.66 lb/hr for the second hour of a cold start was selected because it is higher than the worst-case 1-hour operating conditions for normal operations of 4.115 lb/hr

for Case S14 (100% load, 59 ºF ambient, duct burner on).

bb. ***CO Emissions***

Bicent Response Letter, 5/17/18, item 8.c.i.cc indicated the CO modeling was revised to reflect one turbine in the first hour of a cold start (203.13 lb/hr) with the second turbine in base load at the worst-case 1-hour operating conditions for normal operations with an emission rate of 2.503 lb/hr for Case S14 (100% load, 59 ºF ambient, duct burner on).
The 2.503 lb/hr for normal operation was selected because it is higher than the second hour of a cold start at 1.67 lb/hr.

204.8 lb/cold start – 203.13 lb (first turbine, 1st hr) = 1.67 lb/hr (2nd turbine, 2nd hr)

Tables 16 and *18* and *Malburg Generating Station Emission Rates and Stack Parameters for Refined Modeling* table in *Attachment 6* were revised to address the SCAQMD's requested revisions.

B) 1-Hour Averaging: Scenario 2—"Two Turbines in Hot Startup"

- **Application**

  In *Table 16—Worst-Case Stack Parameters and Emission Rates* on p. 1-33, the scenario is described as "Averaging Period: 1-hour for Hot Start-up Period" for two turbines. In *Table 18—Air Quality Impact Results – Ambient Air Quality Standards* on p. 1-36, this scenario is designated as "Hot Start-up Periods."

  P. 1-37 explains the second scenario is based on two turbines undergoing a non-cold (warm or hot) start. Condition A99.3 limits NOx emissions for a non-cold start to 51.3 lbs and 90 minutes. Condition A99.4 limits CO emissions for a non-cold start to 59.9 lbs and 90 minutes. The Application conservatively used the entire non-cold startup emissions for NOx and CO for the 1-hour averaging.

- **SCAQMD Requested Revisions**

  None.

2) 8-Hour Averaging Period

In *Table 16—Worst-Case Stack Parameters and Emission Rates* on p. 1-33, this scenario is described as "Averaging Period: 8-hours for Start-up/Shutdown Periods." In *Table 18—Air Quality Impact Results – Ambient Air Quality Standards* on p. 1-36, this scenario is described as "Start-up/Shutdown Periods."

P. 1-37 explains that the CO emissions were modeled assuming one cold start-up and shutdown, one hot start [same as non-cold start] and the remaining time with full load emissions including the duct burner. There is no CAAQS or NAAQS 8-hour standard for NOx.

Bicent Response Letter, 5/17/18, item 8.a.i.bb.2)b explains the normal operating emissions is based on the worst-case 1-hour short-term emissions rate, which corresponds to Case S13 (100% load, 38 °F ambient).

b. Fire Pump

On p. 1-33, *Table 16—Worst-Case Stack Parameters and Emission Rates* shows the fire pump is not included for the 1-hour averaging period scenarios, but included for the 8-hour averaging period. As explained above, the modeling is performed in part to support the proposal in the Petition to modify Condition of Certification AQ-C8 to allow testing of the fire pump on the same day as a startup or shutdown event but prohibit the testing during the same hour as a startup (cold and non-cold) or shutdown event.

c. Cooling Tower

The cooling tower is not included in this startup and shutdown analysis because it does not emit NOx or CO emissions.

3. Normal Operations Impact Analysis: Worst Case Modeling Scenario Descriptions, Emission Rates, and Stack Parameters

The derivation of the modeling emission rates in *Table 16----Worst-Case Stack Parameters and Emission Rates* provided in the Application is shown below, as well as the corrections that were requested by the SCAQMD AI Letter, 5/1/18, and provided by Bicent Response Letter, 5/17/18.

g/sec = (lb/hr)(453.59 g/lb)(hr/3600 sec)

NORMAL OPERATING CONDITIONS ANALYSIS

The first analysis is the normal operating conditions analysis for the facility consisting of two combined-cycle turbines, emergency engine for the fire pump, and cooling tower (3 cells). For this analysis, the turbine modeling does not include any startup or shutdown events, with the exception of the annual averaging period.

1-hour Averaging Period

- Turbine
  NOx = 4.115 lb/hr (Case S14) → 0.5185 g/sec
  CO = 2.503 lb/hr (S14) → 0.3154 g/sec
  SO_2 = SOx = 0.157 lb/hr (S14) → 0.0198 g/sec

- Fire Pump (D48)
  NOx = 1.49 lb/hr (from 3.9 g/bhp-hr from A/N 482576) → 0.1877 g/sec
  CO = 0.15 lb/hr (from 0.4 g/bhp from A/N 482576) → 0.0189 g/sec
  SOx = 0.0019 lb/hr (from 0.0049 g/bhp-hr for 15 ppmw fuel) → 2.394 E-4 g/sec

1-hour Federal

- Turbine
  NOx = 4.115 lb/hr (S14) → 0.5185 g/sec
  SOx = 0.157 lb/hr (S14) → 0.0198 g/sec

- Fire Pump (D48)
  The emission rates are based on annual average emissions per USEPA guidance for intermittent sources.

  NOx = (1.49 lb/hr)(~~52~~ **200** hr) /8760-hr averaging = ~~0.0088~~ **0.0342** lb/hr
  → ~~1.114E-3~~ **4.286E-3** g/sec

  SOx = (0.0019 lb/hr)(~~52~~ **200** hr) /8760-hr averaging = ~~1.1278 E-5~~
  4.3378 E-5 lb/hr → ~~1.421E-6~~ **5.466E-6** g/sec

  Note: The Application based the annual averaging modeling on 52 hours. The CEC required the operating hours to be increased to 200 hr/yr because the original modeling was based on 200 hr/yr.

3-hour

- Turbine
  SOx = 0.157 lb/hr (S14) x 3 hr /3-hr averaging = 0.157 lb/hr → 0.0198 g/sec

- Fire Pump (D48)
  SOx = 0.0019 lb/hr x 1 hr /3-hr averaging = 0.00063 lb/hr → 7.98 E-5 g/sec

8-hr

- Turbine
  CO = 2.503 lb/hr (S14) x 8 hr/ 8-hr averaging = 2.503 lb/hr → 0.3154 g/sec

- Fire Pump
  CO = 0.15 lb/hr x 1 hr /8-hr averaging = 0.01875 lb/hr → 2.363 E-3 g/sec

24-hr

- Turbine
  PM_{10} /$PM_{2.5}$ = ~~3.339~~ **3.386** lb/hr x 24 hrs/24-hr averaging = ~~3.339~~ **3.386** lb/hr
  → ~~0.4207~~ **0.4266** g/sec

  Note: The Application modeling was incorrectly based on 3.339 lb/hr PM_{10}, which is the annual average rate based on the condition A63.3 monthly limit for both turbines, not on the maximum emission rate of 3.89 lb/hr (S13) for the FDOC. Bicent Response Letter, 5/17/18, item 8.b.i.aa.1 responded that the modeling was revised to reflect the proposed maximum PM_{10} emission rate of 3.386 lb/hr for the 24-hour averaging period. As discussed above, the SCAQMD will accept the proposed 3.386 lb/hr post turbine upgrade based on recent source tests at the facility.

  SOx = 0.157 lb/hr (S14) x 24 hrs/24-hr averaging = 0.157 lb/hr
  → 0.0198 g/sec

- Fire Pump
  PM_{10} /$PM_{2.5}$ = 0.03 lb/hr (from 0.09 g/bhp-hr PM from A/N 482576)
  x 1 hr/ 24-hr averaging = 0.00125 lb/hr → 1.575 E-4 g/sec

  SOx = 0.0019 lb/hr x 1 hr /24-hr averaging = 0.00007917 lb/hr
  → 9.975 E-6 g/sec

- Cooling Tower (per cell, 3 total)
  The 3-cell tower is modeled as 3 point sources. Therefore, the total emissions are divided by 3 to provide emissions per cell.

  PM_{10} /$PM_{2.5}$ = [(7.27 lb/day)(day/24 hr) /3 cells] x 24 hr /24-hr averaging
  = 0.10 lb/hr/cell → 0.0127 g/sec per cell

  Note: As the Application modeling was based on the higher 7.27 lb/day, re-modeling is not required to reflect the correction to 6.61 lb/day.

Annual Averaging Period

- Turbine

In *Attachment 6,* the *Malburg Generating Station Emission Rates and Stack Parameters for Refined Modeling* table shows the Annual Emissions Calculations are based on 30 cold starts, 26 warm starts, 0 hot starts, 56 shutdowns, 8633 hr normal operation. (Warm starts and hot starts are non-cold starts.) Conditions A99.3, A99.4, A99.5 provides the following limits: 56 starts per year, no more than 30 cold starts per year, cold start 120 minutes, non-cold start 90 minutes, shutdown 30 minutes.

NOx

Condition A99.3 limits cold start, non-cold start, and shutdown emissions, but RECLAIM facility has no annual NOx emissions limit.

8760 hr – (30 cold starts)(2 hr/cold start) – (26 non-cold start) (1.5 hr/non-cold start) – (56 shutdowns)(0.5 hr/shutdown) = 8633 hr normal operation

NOx = [(30 cold starts)(122.8 lb/cold start) + (26 non-cold starts)(51.3 lb/non-cold start) + (56 shutdowns)(4.5 lb/shutdown) + (8633 hr normal operation)(4.158 lb/hr (S13)] /8760-hr averaging
= 41,165.81 lb / 8760-hr = 4.70 lb/hr → 0.5921 g/sec

PM_{10} /$PM_{2.5}$

Condition A63.3 limits PM_{10} to 4876 lb/month per two turbines.

PM_{10} = [(4876 lb/month /2 turbines) x 12 months] / 8760-hr averaging
= 3.340 lb/hr → 0.4207 g/sec

SOx

SOx = [(8760 hr)(0.160 lb/hr (S13)] / 8760-hr averaging
= 0.16 lb/hr → 0.0201 g/sec

Note: The above methodology is acceptable because it yields the same emission rate as calculated from the condition A63.3 limit which will be increased from 214 lb/month to 227 lb/month for two turbines.

[(~~214~~ **227** lb/month /2 turbines) x 12 months] / 8760-hr averaging
= 0.16 lb/hr → 0.0201 g/sec

- Fire Pump

NOx = (1.49 lb/hr)(~~52~~ **200** hr) /8760-hr averaging = ~~0.0088~~ **0.0342** lb/hr
→ ~~1.114E-3~~ **4.286E-3** g/sec

PM_{10} /$PM_{2.5}$ = (0.03 lb/hr)(~~52~~ **200** hr) /8760-hr averaging = ~~0.000178~~

0.0006849 lb/hr → ~~2.244E-5~~ **8.630E-5** g/sec

SOx = (0.0019 lb/hr)(~~52~~ **200** hr) /8760-hr averaging = ~~1.1278 E-5~~
4.3378 E-5 lb/hr → ~~1.421E-6~~ **5.466E-6** g/sec

***Note*:** The Application based the modeling on 52 hours. The CEC required the operating hours to be increased to 200 hr/yr because the original modeling was based on 200 hr/yr.

- Cooling Tower (per cell, 3 total)
  PM_{10} /$PM_{2.5}$ = [(7.27 lb/day)(day/24 hr) /3 cells] x
  8760 hr /8760-hr averaging
  = 0.10 lb/hr/cell → 0.0127 g/sec per cell

  Note: As the Application modeling was based on the higher 7.27 lb/day, re-modeling is not required to reflect the correction to 6.61 lb/day.

STARTUP AND SHUTDOWN ANALYSIS

The second analysis is a separate start-up and shutdown analysis for the two turbines for the short-term averaging periods (1-hour and 8-hour), with the fire pump included for the 8-hour averaging period.

1) 1-Hour Averaging Period

For the 1-hour averaging period, two modeling scenarios for the startup of the turbines are provided.

A) 1-Hour Averaging: Scenario 1—"~~One~~ Two Turbine in Cold Startup"

The Application modeled one turbine undergoing the first hour of a two-hour cold start. SCAQMD AI Letter, 5/1/18, item 8.c.i.cc requested that the modeling be revised to add the simultaneous operation of the second turbine based on worst-case emissions for one hour. Bicent Response Letter, 5/17/18, item 8.c.i.cc explained that the facility is designed so that only one turbine can be in cold start mode for the first hour. The modeling has been revised to reflect one turbine in the first hour of a cold start with the second turbine in the second hour of a cold start.

NOx

- First turbine completes first hour of 2-hour cold start-up.

  ~~61.4~~ **102.14** lb/hr → ~~7.7364~~ **12.8696** g/sec

Note: The Application incorrectly assumed that the first hour emissions are one-half of the cold start limit emissions of 122.8 lbs in condition A99.3. The SCAQMD provided the correction to 102.14 lb/hr.

- Second turbine completes second hour of 2-hour cold start-up
  122.8 lb/cold start - 102.14 lb (first turbine, 1st hr) =
  20.66 lb/hr (2nd turbine, 2nd hr)

  20.66 lb/hr → 2.6032 g/sec

  Note: The Application based the modeling on the operation of one turbine. As requested by the SCAQMD, the modeling was revised to include the simultaneous operation of the second turbine.

CO

- First turbine completes first hour of 2-hour cold start-up.

  ~~102.40~~ **203.13** lb/hr → ~~12.9024~~ **25.5944** g/sec

  Note: The Application incorrectly assumed that the first hour emissions are one- half of the cold start limit emissions of 204.8 lbs in condition A99.4. The SCAQMD provided the correction to 203.13 lb/hr.

- Second turbine operates for one hour (Case S14, 100% load at 59 °F, duct burner on)

  2.503 lb/hr → 0.3154 g/sec

  Note: The Application based the modeling on the operation of one turbine. As requested by the SCAQMD, the modeling was revised to include the simultaneous operation of the second turbine. The 2.503 lb/hr for normal operation was selected because it is higher than the second hour of a cold start at 1.67 lb/hr.

B) 1-Hour Averaging: Scenario 2—"Two Turbines in Hot Startup"

- **Two turbines in non-cold startup—One hour averaging**
  NOx: 51.3 lb for non-cold start, 1.5 hr limit per condition A99.3.

  51.3 lb/hr → 6.4638 g/sec

  CO: 59.9 lb for non-cold start, 1.5 hr limit per condition A99.4

59.9 lb/hr → 7.5474 g/sec

***Note*:** The Application conservatively used the total non-cold start emissions for NOx and CO.

2) <u>8-Hour Averaging Period</u>

- **<u>Turbine</u>**

  In *Attachment 6,* the *Malburg Generating Station Emission Rates and Stack Parameters for Refined Modeling* table shows the Startup Emissions Calculations for 8-hr CO are based on 1 cold start, 0 warm start, 1 hot start, 1 shutdown, 240 minutes normal operation (S13, 100% load at 38 ºF).

  Condition A99.4 limits emissions for cold starts, non-cold starts (warm starts and hot starts), and shutdowns.

  8 hr for averaging period – 2 hr (cold) – 1.5 hr (non-cold) – 0.5 hr (shutdown) = 4 hr normal operating

  CO: Condition A99.4 limits cold start, non-cold start, and shutdown emissions.

  [(1 cold start)(204.8 lb/cold start) + (1 non-cold start)(59.9 lb/non-cold start) + (1 shutdown)(21.6 lb/shutdown) + (4 hr normal operation)(2.529 lb/hr (S13)] /8-hr averaging
  = 37.052 lb/hr → 4.6683 g/sec

- **<u>Fire Pump</u>**

  CO = 0.15 lb/hr x 1 hr /8-hr averaging = 0.01875 lb/hr → 2.363 E-3 g/sec

The modeling scenarios and emission rates from *Table 16----Worst-Case Stack Parameters and Emission Rates* in the Application are shown below, as well as the corrections that were requested by the SCAQMD AI Letter, 5/1/18, and provided by Bicent Response Letter, 5/17/18.

Table 28—Modeled Emission Rates – Normal Operations Impact Analysis (A/N 598922 & 598923—Turbine Upgrade)

Averaging Time	Worst-Case Modeling Scenario	Pollutant	Emissions Per Turbine, lb/hr (g/s)	Emissions for Fire Pump, lb/hr (g/s)	Emissions for Cooling Tower lbs/hr (g/s) (per cell, 3 total)
Normal Operating Conditions Analysis					
1-hour	NO_2: Two turbines continuous operation at 100% load at 59 °F ambient temperature (Case S14). Fire pump continuous maximum operation. CO: Same as NO_2 above. SO_2: Same as NO_2 above.	NO_x	4.115 (0.5185)	1.49 (0.1877)	
		CO	2.503 (0.3154)	0.15 (0.0189)	
		SO_2	0.157 (0.0198)	0.0019 (2.394 E-4)	
1-hour (federal)	NO_2 & SO_2: For turbine, same as 1-hour above. NO_2 & SO_2: For fire pump, annual average emissions.	NO_x	4.115 (0.5185)	~~0.0088 (1.114E-3)~~ **0.0342** [a, b] **(4.286E-3)**	
		SO_2	0.157 (0.0198)	~~1.278E-5 1.421E-6~~ **4.3378E-5** [a, b] **(5.466E-6)**	
3-hour	SO_2: Two turbines continuous operation at 100% load at 59 °F ambient temperature (Case S14). Fire pump continuous maximum operation for one hour.	SO_2	0.157 (0.0198)	0.00063 (7.980E-5)	
8-hour	CO: Two turbines continuous operation at 100% load at 59 °F ambient temperature (Case S14). Fire pump continuous maximum operation for 1 hour.	CO	2.503 (0.3154)	0.01875 (2.363E-3)	
24-hour	PM_{10} / $PM_{2.5}$: Two turbines continuous operation at 100% load at 59 °F ambient temperature (Case S14). Fire pump continuous maximum operation for 1 hour. Cooling tower continuous maximum operation for 24 hours. SO_2: Same as PM_{10} / $PM_{2.5}$ above.	PM_{10}, $PM_{2.5}$	~~3.339 (0.4207)~~ **3.386** [c] **(0.4266)**	0.00125 (1.575E-4)	0.10 (0.0127)
		SO_2	0.157 (0.0198)	0.00007917 (9.975E-6)	
Annual		NO_x	4.70	~~0.0088~~	

	NO_2: Two turbines operate at 100% load for 8633 normal operating hours, 30 cold starts, 26 non-cold starts, and 56 shutdowns, for total of 8760 hours, 65 °F ambient temperature (Case S15). Fire pump continuous maximum operation for ~~50~~ **200** hours. Cooling tower continuous maximum operation for 8760 hours. PM_{10} / $PM_{2.5}$: For turbines, annual emissions based on condition A63.3 limit. For fire pump and cooling tower, same as NO_2 above. SO_2: Same as PM_{10} / $PM_{2.5}$ above.		(0.5921)	~~(1.114E-3)~~ **0.0342** [b] **(4.286E-3)**	
		PM_{10}, $PM_{2.5}$	3.34 (0.4207)	~~0.000178~~ ~~(2.244E-5)~~ **0.0006849** [b] **(8.63E-5)**	0.10 (0.0127)
		SO_2	0.160 (0.0201)	~~1.278E-5~~ ~~1.421E-6~~ **4.3378E-5** [b] **(5.466E-6)**	
Startup and Shutdown Analysis					
1-hour	*Scenario One—One Turbine in Cold Start-up*, ***Second Turbine in Cold Start-up (NOx) or Max Baseload (CO)*** [d] One turbine complete first hour of 2-hour cold start-up. **Second turbine complete second hour of 2-hour cold start-up.**	NO_x **NO_x**	~~61.4~~ ~~(7.7364)~~ **102.14** [e] **(12.8696)** **20.66** **(2.6032)**		
	One turbine complete first hour of 2-hour cold start-up. **Second turbine continuous operation at 100% load at 59 °F ambient temperature (Case S14).**	CO **CO**	~~102.40~~ ~~(12.9024)~~ **203.13** [f] **(25.5944)** **2.503** **(0.3154)**		
1-hour	*Scenario Two—Two Turbines in Non-Cold (Warm or Hot) Start-up* NO_2: Two turbines complete non-cold startup.	NO_x	51.30 (6.4638)		

	CO: Same as NO_2 above.	CO	59.90 (7.5474)		
3-hour	No NO_2 or CO standards.				
8-hour	CO: Two turbines complete 1 cold start, 1 non-cold start, 1 shut-down and balance of period at 100% load at 38 °F ambient temperature (Case S13). Fire pump continuous maximum operation for 1 hour.	CO	37.052 (4.6683)	0.01875 (2.363E-3)	

[a] The 1-hour NO_2 and SO_2 NAAQS assessment for the fire pump is based on annual average emissions per USEPA guidance for intermittent source.

[b] The Application based the fire pump modeling on 52 hours. The CEC required the operating hours to be increased to 200 hr/yr because the original modeling was based on 200 hr/yr.

[c] The Application modeling was incorrectly based on 3.339 lb/hr PM_{10}, which is the annual average rate based on the condition A63.3 monthly limit for both turbines, not on the maximum emission rate of 3.89 lb/hr (S13) for the FDOC. Bicent Response Letter, 5/17/18, item 8.b.i.aa.1 responded that the modeling was revised to reflect the proposed maximum PM_{10} emission rate of 3.386 lb/hr for the 24-hour averaging period. As discussed above, the SCAQMD will accept the proposed 3.386 lb/hr post turbine upgrade based on recent source tests at the facility.

[d] The Application based the modeling on the operation of one turbine. As requested by the SCAQMD, the modeling was revised to include the simultaneous operation of the second turbine.

[e] The Application incorrectly assumed that the first hour emissions are one-half of the cold start limit emissions of 122.8 lbs in condition A99.3. The SCAQMD provided the correction to 102.14 lb/hr.

[f] The Application incorrectly assumed that the first hour emissions are one- half of the cold start limit emissions of 204.8 lbs in condition A99.4. The SCAQMD provided the correction to 203.13 lb/hr.

Table 29—Modeled Stack Parameters – Normal Operations Impact Analysis (A/N 598922 & 598923—Turbine Upgrade)

Pollutants	Averaging Period	Stack Diameter (m)	Stack Height (m)	Exhaust Temp (°K)	Exhaust velocity (m/s)	Case
Normal Operating Conditions Analysis						
Turbine						
NO_2, CO, SO_2	1-hour	3.6576	33.53	377.59	13.844	S14
SO_2	3-hour	3.6576	33.53	377.59	13.844	S14
CO	8-hour	3.6576	33.53	377.59	13.844	S14
SO_2, $PM_{10}/PM_{2.5}$	24-hour	3.6576	33.53	377.59	13.844	S14
NO_2, SO_2, $PM_{10}/PM_{2.5}$	Annual	3.6576	33.53	378.15	13.743	S15

Fire pump						
All	All	0.1143	3.51	738.15	69.458	--
Cooling tower (each cell, 3 cells total)						
$PM_{10}/PM_{2.5}$	24-hour, Annual	6.7056	13.73	316.00	10.028	--
Start-up and Shutdown Analysis						
Turbine						
NO_2, CO	1-hour	3.6576	33.53	375.37	9.556	S1
	1-hour	3.6576	33.53	377.59	13.844	S14 [a, b]
CO	8-hour	3.6576	33.53	375.37	9.556	S1
Fire pump						
CO	8-hour	0.1143	3.51	738.15	69.458	--

[a] The Application based the modeling on the operation of one turbine. As requested by the SCAQMD, the modeling was revised to include the simultaneous operation of the second turbine.

[b] For Scenario One—One Turbine in Cold Start-up, Second Turbine in Max Baseload (CO): Second turbine is in continuous operation at 100% load at 59 °F ambient temperature (Case S14).

SCAQMD Modeling Review Memo

Due to time constraints, SCAQMD Modeler Sam Wang re-ran the AERMOD and HRA using the correct meteorological data, ozone data, receptors, control pathways, source groups, background air quality monitoring data for all operating scenarios. The Memo provided the following table.

Table 29A
Modeled Stack Parameters – Normal Operations Impact Analysis

Pollutants	Averaging Period	Stack Diameter (m)	Stack Height (m)	Exhaust Temp (°K)	Exhaust velocity (m/s)	Case
Normal Operating Conditions Analysis						
Turbine						
NO_2, CO, SO_2	1-hour	3.6576	33.53	377.59	13.844	S14
SO_2	3-hour	3.6576	33.53	377.59	13.844	S14
CO	8-hour	3.6576	33.53	377.59	13.844	S14
SO_2, $PM_{10}/PM_{2.5}$	24-hour	3.6576	33.53	377.59	13.844	S14

NO_2, SO_2, $PM_{10}/PM_{2.5}$	Annual	3.6576	33.53	377.59	13.844	S14
Fire pump						
All	All	0.1143	3.51	738.15	69.458	--
Cooling tower (each cell, 3 cells total)						
$PM_{10}/PM_{2.5}$	24-hour, Annual	6.7056	13.73	316.00	10.028	--
Start-up and Shutdown Analysis						
Turbine						
NO_2, CO	1-hour	3.6576	33.53	375.37	9.556	S1
	1-hour	3.6576	33.53	377.59	13.844	S14 [a, b]
CO	8-hour	3.6576	33.53	375.37	9.556	S1
Fire pump						
CO	8-hour	0.1143	3.51	738.15	69.458	--

[a] The Application based the modeling on the operation of one turbine. As requested by the SCAQMD, the modeling was revised to include the simultaneous operation of the second turbine.

[b] For Scenario One—One Turbine in Cold Start-up, Second Turbine in Max Baseload (CO): Second turbine is in continuous operation at 100% load at 59 °F ambient temperature (Case S14).

4. <u>Impacts during Normal Operation – Facility</u>

The modeling results for the Normal Operating Conditions Analysis (<u>Normal Operating Conditions Analysis</u> and <u>Startup and Shutdown Analysis</u>), are shown in the table below. The modeling results from *Table 18—Air Quality Impact Results - Ambient Air Quality Standards* in the Application are shown in the table, as well as the corrections that were requested by the SCAQMD AI Letter, 5/1/18, and provided by Bicent Response Letter, 5/17/18, including a revised *Table 18* on p. 24 – 25 of the letter.

For the attainment pollutants, the maximum modeled concentrations, combined with background concentrations, are below the applicable ambient air quality standards. For the nonattainment concentrations, the maximum modeled concentrations are below the Rule 1303 thresholds.

Table 30 - Modeled Results -Normal Operations Impact Analysis – Total Facility (A/N 598922 & 598923—Turbine Upgrade)

Attainment Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m³)	Background Concentration (µg/m³)	Total Concentration (µg/m³)	State Standard CAAQS (µg/m³)	Federal Standard, NAAQS (µg/m³)	Exceeds Any Threshold?
Normal Operating Conditions Analysis							
NO_2 *	1-hour	126.6	138.5	265.1	339	--	No
	1-hour (98th percentile)	~~3.39~~ 3.48	110.6	114.08	--	188	No
	Annual	~~0.47~~ 0.50	31.8	32.3	57	100	No
SO_2	1-hour	0.42	35.1	35.5	655	--	No
	1-hour (99th percentile)	0.14	11.5	11.6	--	196	No
	3-hour	0.15	35.1	35.3	--	1,300	No
	24-hour	0.04	3.7	3.74	105	--	No
	Annual	0.016	0.8	0.82			80
CO	1-hour	33.0	6,871	6,904	23,000	40,000	No
	8-hour	1.89	4,466	4,468	10,000	10,000	No
PM_{10}	24-hour	~~0.85~~ 0.86	63	63.9	--	150	No
Non-Attainment Pollutant	**Averaging Period**	**Maximum Modeled Concentration (µg/m³)**	**State Standard CAAQS (µg/m³)**	**Federal Standard, NAAQS (µg/m³)**	**Rule 1303 Thresholds (µg/m³)**		**Exceeds Any Threshold?**
PM_{10}	24-hour	~~0.96~~ 0.98	50		2.5		No
	Annual	~~0.34~~ 0.35	20		1		No
$PM_{2.5}$	24-hour (98th percentile)	~~0.69~~ 0.70		35	2.5		No
	Annual Maximum	~~0.34~~ 0.35	12		1		No
	3-year average of 24-hour yearly 95%	0.31		12	1		
Startup and Shutdown Analysis							
Attainment Pollutant	**Averaging Period**	**Maximum Modeled Concentration (µg/m³)**	**Background Concentration (µg/m³)**	**Total Concentration (µg/m³)**	**State Standard CAAQS (µg/m³)**	**Federal Standard, NAAQS (µg/m³)**	**Exceeds Any Threshold?**
Scenario One—One Turbine in Cold Start-up, **Second Turbine in Cold Start-up (NOx) or Max Baseload (CO),** Fire Pump Not in Operation							
NO_2 *	1-hour	~~43.10~~ 85.58	138.5	~~181.6~~ 224.1	339	--	No

	1-hour (98th percentile)	~~33.06~~ 65.78	110.6	~~143.7~~ 176.4	--	188	No
CO	1-hour	~~71.87~~ 143.6	6,871	~~6,943~~ 7014.6	23,000	40,000	No
Scenario Two--Two Turbines in Non-Cold (Warm or Hot) Start-up, Fire Pump Not in Operation							
NO_2 *	1-hour	70.74	138.5	209.2	339	--	No
	1-hour (98th percentile)	54.90	110.6	165.5	--	188	No
CO	1-hour	82.60	6,871	6,954	23,000	40,000	No
Two Turbines Complete Cold Start, Non-Cold Start, Shutdown and Balance at Normal Operation, Fire Pump Operate 1 hr							
CO	8-hour	32.14	4,466	4,498	10,000	10,000	No

* 1-hr NO_2 impacts for comparison to CAAQS under Normal Operating Conditions evaluated with the Ozone Limiting Method (OLM) for CAAQS. All other NO_2 1-hour and annual impacts evaluated assuming 100% conversion of NOx to NO2.

SCAQMD Modeling Review Memo

Due to time constraints, SCAQMD Modeler Sam Wang re-ran the AERMOD and HRA using the correct meteorological data, ozone data, receptors, control pathways, source groups, background air quality monitoring data for all operating scenarios. The modeler also modeled the air quality impacts by each individual sources (per permit unit) and compared the modeling results to the applicable thresholds for all criteria pollutants for different averaging times. The air quality impacts from each turbine do not exceed any NAAQS/CAAQS and any applicable thresholds in Table A-2 in Rule 1303 and Table A-2 in Rule 2005.
The Memo provided the following three tables.

Table 30A
Modeled Results -Normal Operations Impact Analysis – Total Facility

Attainment Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Concentration ($\mu g/m^3$)	State Standard, CAAQS[c] ($\mu g/m^3$)	Federal Standard, NAAQS[c] ($\mu g/m^3$)	Exceeds Any Threshold?
Normal Operating Conditions Analysis							
NO_2 [a]	1-hour	80.54	186.3	266.8	339	--	No
	1-hour (98th percentile)	3.78	116.0	119.78	--	188	No
	Annual (Federal)	0.478	39.8	40.28	--	100	No
	Annual Maximum (State)	0.507	41.7	42.21	57	--	No

SO_2	1-hour	0.16	34.97	35.13	655	--	No
	1-hour (99th percentile)	0.16	9.9	10.06	--	196	No
	3-hour	0.12	35.1	35.22	--	1,300	No
	24-hour	0.05	3.7	3.75	105	--	No
CO	1-hour	9.01	6,954	6,963	23,000	40,000	No
	8-hour	1.23	5,244	5,245	10,000	10,000	No
PM_{10}	24-hour	0.84	96	96.8	--	150	No

Non-Attainment Pollutant[b]	**Averaging Period**	**Maximum Modeled Concentration (µg/m³)**	**State Standard CAAQS (µg/m³)**	**Federal Standard, NAAQS (µg/m³)**	**Rule 1303 Thresholds (µg/m³)**	**Exceeds Any Threshold?**
PM_{10}	24-hour	1.07	50	51.07	2.5	No
	Annual Maximum	0.35	20		1	No
$PM_{2.5}$	24-hour (98th percentile)	0.77	31.8	35	2.5	No
	Annual Maximum	0.347	12		1	No

Startup and Shutdown Analysis

Pollutant	**Averaging Period**	**Maximum Modeled Concentration (µg/m³)**	**Background Concentration (µg/m³)**	**Total Concentration (µg/m³)**	**State Standard CAAQS (µg/m³)**	**Federal Standard, NAAQS (µg/m³)**	**Exceeds Any Threshold?**
Scenario One—One Turbine in Cold Start-up, **Second Turbine in Cold Start-up (NOx) or Max Baseload (CO),** Fire Pump Not in Operation							
NO_2 [a]	1-hour	78.11	186.3	264.4	339	--	No
	1-hour (98th percentile)	57.31	116.0	173.3	--	188	No
CO	1-hour	131.21	6,954	7,085	23,000	40,000	No
Scenario Two--Two Turbines in Non-Cold (Warm or Hot) Start-up, Fire Pump Not in Operation							
NO_2 [a]	1-hour	65.12	186.3	251.4	339	--	No
	1-hour (98th percentile)	47.85	116.0	163.9	--	188	No
CO	1-hour	76.04	6,954	7,030	23,000	40,000	No
Two Turbines Complete Cold Start, Non-Cold Start, Shutdown and Balance at Normal Operation, Fire Pump Operate 1 hr							
CO	8-hour	31.31	5,244	5,275	10,000	10,000	No

a 1-hr NO_2 impacts for comparison to CAAQS under Normal Operating Conditions with the Ozone Limiting Method (OLM). All other NO_2 1-hour and annual impacts evaluated assuming 100% conversion of NOx to NO2.

b Effective July 26, 2013, the South Coast Air Basin has been re-designated to attainment for the federal 24-hour PM10 AAQS. The South Coast Air Basin is designated non-attainment for the state PM10 standards, and state and federal PM2.5 standards; therefore, project increments are compared to the significant change thresholds in Rule 1303.

c Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted. On April 12, 2010, the U.S. EPA established a new 1-hour NO2 standard of 100 ppb (188 µg/m3). The form of the federal 1-hour NO2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, can be excluded from compliance with the federal 1-hour NO2 standard. On June 2, 2010, the U.S. EPA established a new 1-hour SO2 standard of 75 ppb (196 µg/m3). The form of the federal 1-hour SO2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations. On December 14, 2012, the national annual PM2.5 primary standard was lowered from 15 µg/m3 to 12.0 µg/m3. The existing national 24- hour PM2.5 standards (primary and secondary) were retained at 35 µg/m3 (98th percentile, averaged over 3 years), as was the annual secondary standard of 15 µg/m3. The existing 24-hour PM10 standards (primary and secondary) of 150 µg/m3 also were retained. The form of the annual primary and secondary standards is the annual mean, averaged over 3 years.

Table 30B
Modeled Results -Normal Operations Impact Analysis – Turbine 1

Attainment Pollutant	**Averaging Period**	**Maximum Modeled Concentration ($\mu g/m^3$)**	**Background Concentration ($\mu g/m^3$)**	**Total Concentration ($\mu g/m^3$)**	**State Standard, CAAQS[c] ($\mu g/m^3$)**	**Federal Standard, NAAQS[c] ($\mu g/m^3$)**	**Exceeds Any Threshold?**
Normal Operating Conditions Analysis							
NO_2 [a]	1-hour	1.87	186.3	188.17	339	--	No
	1-hour (98th percentile)	1.81	116.0	117.81	--	188	No
	Annual (Federal)	0.22	39.8	40.02	--	100	No
	Annual Maximum (State)	0.23	41.7	41.93	57	--	No
SO_2	1-hour	0.08	34.97	35.05	655	--	No
	1-hour (99th percentile)	0.08	9.9	9.98	--	196	No
	3-hour	0.06	35.1	35.16	--	1,300	No
	24-hour	0.02	3.7	3.72	105	--	No
CO	1-hour	1.26	6,954	6,955	23,000	40,000	No
	8-hour	0.59	5,244	5,245	10,000	10,000	No
PM_{10}	24-hour	0.40	96	96.4	--	150	No
Non-Attainment Pollutant[b]	**Averaging Period**	**Maximum Modeled Concentration ($\mu g/m^3$)**	**State Standard CAAQS ($\mu g/m^3$)**	**Federal Standard, NAAQS ($\mu g/m^3$)**	**Rule 1303 Thresholds ($\mu g/m^3$)**		**Exceeds Any Threshold?**
PM_{10}	24-hour	0.51	50	50.84	2.5		No
	Annual Maximum	0.16	20		1		No

$PM_{2.5}$	24-hour (98th percentile)	0.37	31.8	35	2.5	No
	Annual Maximum	0.16	12		1	No

Table 30C
Modeled Results -Normal Operations Impact Analysis – Turbine 2

Attainment Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m³)	Background Concentration (µg/m³)	Total Concentration (µg/m³)	State Standard, CAAQS[c] (µg/m³)	Federal Standard, NAAQS[c] (µg/m³)	Exceeds Any Threshold?
Normal Operating Conditions Analysis							
NO_2 [a]	1-hour	1.87	186.3	188.17	339	--	No
	1-hour (98th percentile)	1.81	116.0	117.81	--	188	No
	Annual (Federal)	0.22	39.8	40.02	--	100	No
	Annual Maximum (State)	0.23	41.7	41.93	57	--	No
SO_2	1-hour	0.08	34.97	35.05	655	--	No
	1-hour (99th percentile)	0.08	9.9	9.98	--	196	No
	3-hour	0.06	35.1	35.16	--	1,300	No
	24-hour	0.02	3.7	3.72	105	--	No
CO	1-hour	1.26	6,954	6,955	23,000	40,000	No
	8-hour	0.59	5,244	5,245	10,000	10,000	No
PM_{10}	24-hour	0.40	96	96.4	--	150	No
Non-Attainment Pollutant[b]	**Averaging Period**	**Maximum Modeled Concentration (µg/m³)**	**State Standard CAAQS (µg/m³)**	**Federal Standard, NAAQS (µg/m³)**	**Rule 1303 Thresholds (µg/m³)**		**Exceeds Any Threshold?**
PM_{10}	24-hour	0.51	50	50.84	2.5		No
	Annual Maximum	0.16	20		1		No
$PM_{2.5}$	24-hour (98th percentile)	0.37	31.8	35	2.5		No
	Annual Maximum	0.16	12		1		No

♦♦♦

III. COMMISSIONING IMPACTS ANALYSES

Pp. 1-36 to 1-37 of the Application states the commissioning activities associated with the upgrade package is stated to occur over a period of two weeks. The modeling is based on maximum CO and NOx emission rates of 33.0 and 36.35 lbs/hr, respectively, the same as was modeled for the original commissioning as set forth in the FDOC, pp. 41 and 53, respectively. Commissioning activities are assumed to occur for only one turbine at a time and the fire pump will not be tested during commissioning activities.

Bicent Response Letter, 5/17/18, item 8.a.ii.aa. clarified that the basis for the stack parameters for the commissioning modeling is the worst-case minimum load condition from the screening analysis which is Case S1 (60% load at 38 ºF).

The response to item 8.d.i. clarified that only one turbine was modeled because one turbine at a time would be undergoing commissioning activities with the other turbine being non-operational. Normal operations would not occur until both turbines have completed commissioning. As a result of this clarification, condition E193.2 will state that one turbine may be commissioned at a time. Further, the commissioning for both turbines shall be completed before normal operation for either turbine may commence. Still further, emergency internal combustion engine for the fire pump shall not be tested during commissioning activities.

As discussed above, the response to item 7.a.i. clarified that the commissioning after the turbine upgrade will be revised to be based on the commissioning schedule, as well as emissions, fuel use, and hours for each activity, that was provided by Siemens in support of Case No. 5727-4 for the petition for short variance submitted on 4/5/18 for the commissioning that would take place after the upgrade of the facility's control system. Accordingly, the response to item 8.d.i. provided revised commissioning modeling based on revised CO and NOx emission rates. The CO emission rates have increased from 33.0 lb/hr to 102.4 lb/hr for 1-hr averaging and 121.225 lb/hr for 8-hr averaging. The NOx emission rate has increased from 36.35 lb/hr to 61.4 lb/hr for 1-hr averaging.

Bicent Response Letter, 10/20/18, item 8.d.ii.aa - cc, clarified the 102.4 lb/hr CO and the 61.4 lb/hr NOx had been based on the first hour of the two-hour cold startup emission limit in conditions A99.4 and A99.3. However, SCAQMD AI Letter, 5/1/18, item 8.c.i.aa – bb, had explained that the applicant's assumption that the first hour of emissions is equal to one-half of the total emissions is incorrect. The SCAQMD had requested that the modeling for the first hour of a cold start be revised

to be based on 203.13 lb CO and 102.14 lbs NOx for the "Startup and Shutdown Analysis," as discussed above. Accordingly, the response to item 8.d.ii.aa - cc provided revised commissioning modeling based on revised CO and NOx emission rates for the first hour of a cold startup. The CO emission rate was increased from 102.4 lb to 203.13 lb for 1-hr averaging. The NOx emission rate was increased from 61.4 lb to 102.14 lb for 1-hr averaging. The revised emission rates are acceptable.

Bicent did not revise the CO for the 8-hour averaging period. The emissions were based on two non-cold starts (119.8 lb), two shutdowns (100 lb), and 7.5 hours of commissioning (750 lb) for a total of 969.8 lb or 121.225 lb/hr. The two starts and shutdowns are in accord with the condition A99.3 and A99.4 limit of two startups per day. For the non-cold starts, the 119.8 lb for two non-cold starts was based on the condition A99.4 limit of 59.9 lb CO per non-cold startup over 90 minutes. The calculation conservatively assumed that the entire 55.9 lb per non-cold start would occur over 0.5 hr. For the shutdowns, the 100 lb for two shutdowns was based on the uncontrolled steady state rate of 100 lb/hr at 0.5 hr per shutdown, or 50 lb/shutdown. (The 100 lb/hr had been accepted by the SCAQMD for Case No. 5727-4.) The condition A99.4 limit of 10.8 lb CO per shutdown over 30 minutes cannot be used because the CO catalyst is still above ambient temperature and continue to operate for a portion of the shutdown. The 750 lb CO was based on the uncontrolled steady-state rate of 100 lb/hr.

(2 non-cold starts)(0.5 hr/non-cold start) + (2 shutdowns)(0.5 hr/shutdown) + (7.5 hr normal operation) = 9.5 hr period

Note: The 9.5 hours is conservatively higher than the 8 hours required for the 8-hr averaging period.

(2 non-cold startups)(59.9 lb/non-cold startup) +
(2 shutdowns)(50 lb/shutdown) + (100 lb/hr uncontrolled)(7.5 hr)
= 969.8 hr /8 hr = 121.225 lb/hr

Note: Although one of the startups should have been a cold start (203.1 lb/hr for one hr), the use of 7.5 hours of normal operation instead of the required 6 hours to bring total hours to 8 hours, compensates for the assumption of 2 non-cold starts.

The emissions rates and maximum predicted impacts are shown below for the Application, followed by the revisions set forth in Bicent Response Letter, 5/17/18, and Bicent Response Letter, 10/21/18, respectively.

g/sec = (lb/hr)(453.59 g/lb)(hr/3600 sec)

Table 31 - Worst Case Modeling Scenario Descriptions and Emission Rates for Commissioning (A/N 598922 & 598923—Turbine Upgrade)

Averaging Time	Worst-Case Modeling Scenario	Pollutant	Emissions Per Turbine
1-hour	NO_2: One turbine in commissioning (first hour of cold start), other turbine not in operation. CO: Same as NO_2 above.	NO_x	~~36.35 lb/hr (4.58 g/sec)~~ Application ~~61.4 lb/hr (7.7364 g/sec)~~ Bicent Response Letter, 5/17/18 102.14 lb/hr (12.902 g/sec) Bicent Response Letter, 10/21/18
		CO	~~33.0 lb/hr (4.16 g/sec)~~ Application ~~102.4 lb/hr (12.9024 g/sec)~~ Bicent Response Letter, 5/17/18 203.13 lb/hr (25.5944 g/sec) Bicent Response Letter, 10/21/18
8-hour	CO: One turbine in commissioning (two non-cold starts, two shutdowns, 7.5 hr at steady-state uncontrolled rate). Note: There should be one cold start and one non-cold start, instead of two non-cold starts. However, the 7.5 hr at steady state uncontrolled rate, instead of the required 6 hr to arrive at a total of 8 hrs, compensates for the use of two non-cold starts. Other turbine not in operation.	CO	~~20.60 lb/hr (2.60 g/sec)~~ Application 121.225 lb/hr (15.2744 g/sec) Bicent Response Letter, 5/17/18, & same for Bicent Response Letter, 10/20/18.

Table 32 - Modeled Emission Rates and Stack Parameters – Commissioning for One Turbine (A/N 598922 & 598923—Turbine Upgrade)

Pollutants	Averaging Period	Stack Diameter (m)	Stack Height (m)	Exhaust Temp (°K)	Exhaust velocity (m/s)	Case
NO_2	1-hour	3.6576	33.53	375.37	9.556	S1
CO	1-hour	3.6576	33.53	375.37	9.556	S1
	8-hour	3.6576	33.53	375.37	9.556	S1

SCAQMD AI E-mail, 1/9/19, item 8.d.iii.aa. stated that the revised commissioning modeling results provided for Bicent Response Letter, 5/17/18, item 8.d.i, were (1) 1-hr CO: 102.4 lb/hr resulted in 185.2 µg/m^3; (2) 8-hr CO: 121.225 lb/hr resulted in 117.8 µg/m^3, and (3) 1-hr NOx: 61.4 lb/hr resulted in 83.8 µg/m^3. The most recent revised modeling results provided for Bicent Response Letter, 10/20/18, item 8.d.ii.aa, were (1) 1-hr CO: 203.13 lb/hr resulted in 142.57 µg/m^3; (2) 8-hr CO: 121.225 lb/hr

resulted in 53.10 µg/m^3, and (3) 1-hr NOx: 102.4 lb/hr resulted in 71.69 µg/m^3. For the 1-hr CO and 1-hr NOx, the emissions rates increased from the May submittal to the October submittal but the maximum concentrations decreased. For the 8-hr CO, the emissions rate remained the same but the maximum concentration decreased. Therefore, an explanation for the discrepancies was requested. Item 8.d.iii.bb. stated that the maximum impact for the 1-hr federal NOx standard was included [in the Application] and in the Bicent Response Letter, 5/17/18, but not the Bicent Response Letter, 10/20/18. Therefore, please provide the missing maximum impact for the federal 1-hr federal NOx standard.

Bicent Response Letter, 1/23/19, item 8.d.iii.aa 1) indicated the modeling results presented in the Bicent Response Letter, 10/20/18, are for one turbine since only one turbine at a time would undergo commissioning activities. The EPA Model AERMOD was revised between the May and October 2018 responses which also resulted in a change in concentration. For item 8.d.iii.bb, Bicent responded that since the commissioning activities will be less than 50 hours per year for either turbine, and therefore, would not be considered statistically significant for the probabilistic form of the federal 1-hour standard.

For the table below, the "Maximum Predicted Impact (µg/m^3)" and "Total Predicted Concentration µg/m^3)" columns contain three sets of results, the first two of which are crossed out. The first entry is the value from the Application, the second entry is from the Bicent Response Letter, 5/17/18, and the third entry is from the Bicent Response Letter, 10/20/18.

Table 33 - Modeled Results – Commissioning for One Turbine (A/N 598922 & 598923—Turbine Upgrade)

Pollutant	Averaging Period	Maximum Predicted Impact (µg/m^3)	Background Concentration (µg/m^3)	Total Predicted Concentration (µg/m^3)	State Standard CAAQS (µg/m^3)	Federal Standard, Primary NAAQS (µg/m^3)	Exceeds Any Threshold?
NO_2	1-hour	~~25.51~~ [a] **Application** ~~83.8~~ [b] **Bicent Letter, 5/17/18** **71.69** [c] **Bicent Letter, 10/20/18**	138.5	~~164.01~~ [a] **Application** ~~222.3~~ [b] **Bicent Letter, 5/17/18** **195.9** [c] **Bicent Letter, 10/20/18**	339	--	No
	Federal 1-hour	~~19.57~~ ~~62.3~~ **N/A**	110.6	~~130.17~~ ~~172.9~~ **N/A**	--	188	No
CO	1-hour	~~23.16~~	6871	~~6894.16~~	23,000	40,000	No

		~~185.2~~ **142.57**		~~7056~~ **7013.6**			
	8-hour	~~14.46~~ ~~117.8~~ **53.10**	4466	~~4480.4,6~~ ~~4584~~ **4519.1**	10,000	10,000	No

a For the maximum predicted impacts from the Application (first set of results), the 1-hr NO_2 impacts for comparison to CAAQS under Normal Operating Conditions was evaluated with the Ozone Limiting Method (OLM) for CAAQS. All other NO_2 1-hour and annual impacts evaluated assuming 100% conversion of NOx to NO_2.

b, c For maximum predicted impacts from Bicent Response Letter, 5/17/18, and Bicent Response Letter, 10/20/18 (second and third set of results, respectively): 1-hour NO_2 impacts evaluated using the new ARM_2 model option with default conversion of NOx to NO_2.

c The modeled concentration of 71.69 µg/m^3 was adjusted to 57.35 using ARM2 (0.8).

SCAQMD Modeling Review Memo

Due to time constraints, SCAQMD Modeler Sam Wang re-ran the AERMOD and HRA using the correct meteorological data, ozone data, receptors, control pathways, source groups, background air quality monitoring data for all operating scenarios.

The Memo provided the following table.

Table 33A
Modeled Results – Commissioning for One Turbine [a,b]

Pollutant	Averaging Period	Maximum Predicted Impact (µg/m^3)	Background Concentration (µg/m^3)	Total Predicted Concentration (µg/m^3)	State Standard CAAQS (µg/m^3)	Federal Standard, Primary NAAQS (µg/m^3)	Exceeds Any Threshold ?
NO_2	1-hour	129.98	186.3	316.28	339	--	No
CO	1-hour	257.86	6,954	7,212	23,000	40,000	No
	8-hour	102.20	5,244	5,346	10,000	10,000	No

a. For the maximum predicted impacts from the Application (first set of results), the 1-hr NO_2 impacts for comparison to CAAQS under Normal Operating Conditions was evaluated with the Ozone Limiting Method (OLM) for CAAQS. All other NO_2 1-hour and annual impacts evaluated assuming 100% conversion of NOx to NO_2.

b. For maximum predicted impacts from Bicent Response Letter, 5/17/18, and Bicent Response Letter, 10/20/18 (second and third set of results, respectively): 1-hour NO_2 impacts evaluated using the new ARM_2 model option with default conversion of NOx to NO_2.

♦♦♦

IV. FUMIGATION IMPACTS ANALYSIS

On p. 1-37, the Application indicated that fumigation analyses were conducted for inversion breakup conditions. The worst case short-term operating conditions from

the screening results for the turbines (Case S14) was modeled for fumigation. Since AERSCREEN is a single point source model, only one of the two turbine stacks were modeled. Other AERSCREEN inputs were the BPIP-PRIME values used for the facility analyses for the north turbine stack (nearest the property fenceline), the AERSURFACE values for the MGS site for annual conditions shown in the Modeling Protocol, the range of ambient temperatures analyses in the facility screening analyses (38 to 94 °F), a minimum fenceline distance of 16 meters, no flagpole receptors, a minimum wind speed of 0.5 m/s with a 10-meter anemometer height, and flat terrain (fumigation requires the specification of RURAL dispersion). Impacts were initially evaluated for unitized emission rates (1.0 g/s). The results of AERSCREEN indicate that there will be no fumigation impacts due to the project. Thus, fumigation impacts were not assessed any further.

Bicent Response Letter, 10/20/18, item 15.a. - d. provided the following requested additional information on the fumigation analysis in the Application.

- As noted in the AERSCREEN User's Guide (EPA-454/B-16-004, December 2016, pp. 33, 57), the minimum distance from the source to the nearest shoreline must be less than 3000 meters for shoreline fumigation impacts to be calculated. Since these criteria is not met for MGS, shoreline fumigation impacts were not calculated.

- Fumigation analyses with the EPA Model AERSCREEN (version 16216) were conducted for inversion breakup conditions based on EPA guidance given in EPA-454/R-92-019 (EPA, 1992). The annual average stack parameters (Scenario S14 for 100 percent load at 59 °F) were modeled. Shoreline fumigation impacts were not assessed since the nearest distance to the shoreline of any large bodies of water is greater than 3 kilometers. Since AERSCREEN is a single point source model, only one of the two turbine stacks were modeled. Other AERSCREEN inputs were the BPIP-PRIME values used for the facility analysis for the eastern turbine stack, the AERSURFACE values used by the SCAQMD for generating the Colton meteorological data (i.e., 0.18 noontime surface albedo, 0.543 meter surface roughness, and 1.37 Bowen ratio), the range of ambient temperatures analyses in the facility screening analyses (38 to 94 °F), a minimum fenceline distance, URBAN dispersion conditions (fumigation results default to RURAL dispersion), no flagpole receptors, a minimum wind speed of 0.5 m/s with a 10-meter anemometer height, and flat terrain. Impacts were initially evaluated for unitized emission rates (1.0 g/s).

- If fumigation impacts exceed AERSCREEN maxima, then fumigation impacts longer than 1-hour averages will be evaluated based on Section 4.5.3 of Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised

(EPA-454/R-92-019) guidance on converting to 3-, 8- and 24-hour average concentrations. For the MGS fumigation analysis, AERSCREEN determined that there were no meteorological conditions fitting the inversion breakup criteria. Therefore, no fumigation impacts were calculated to occur.

- All of the fumigation impacts are less than the AERSCREEN maxima predicted to occur under normal dispersion conditions anywhere offsite. Since fumigation impacts are less than the maximum overall AERSCREEN impacts, no further analysis of additional short-term averaging times is required as described in Section 4.5.3 of EPA-454/R-92-019 (EPA, 1992a).

SCAQMD Modeling Review Memo
SCAQMD has no comment on applicant's fumigation modeling files and agrees with the applicant's conclusion.

♦♦

- ***Rule 1303(b)(2)--Offsets***
  Offsets for PM_{10}, VOC, and SOx are not required because the 30-day averages remain the same.

- ***Rule 1303(b)(3)-Sensitive Zone Requirements***
- ***Rule 2005(e)-Trading Zone Restrictions***
  Rule 1303(b)(3)--Unless credits are obtained from the Priority Reserve, facilities located in the South Coast Air Basin are subject to the Sensitive Zone requirements specified in Health and Safety Code Section 40410.5. A facility located in Zone 1 (coastal), such as the MGS, may obtain ERCs originated in Zone 1 only.

  Rule 2005(e)--Any increase in an annual Allocation to a level greater than the facility's starting plus non-tradable Allocations, and all emissions from a new or relocated facility must be fully offset by obtaining RTCs originated in one of the two trading zones as illustrated in the RECLAIM Trading Zones Map. A facility in Zone 1 may only obtain RTCs originated in Zone 1.

  Bicent is not required to obtain ERCs or RTCs for the turbine upgrade project. The facility is expected to be in compliance with these rules if ERCs and/or RTCs are required for any future project.

- ***Rule 1303(b)(4)-Facility Compliance***
  The facility complies with all applicable rules and regulations of the District. The facility has received no public complaints, one Notice to Comply (NCs) and two Notices of Violations (NOVs) since the current Title V renewal permit was issued on November 3, 2015. Below is a summary of

the Notices to Comply and Notices of Violation. There are currently no outstanding compliance issues with this facility.

- Compliance History Since Title V Renewal on November 3, 2015
  The facility has been subject to both self-reporting requirements and SCAQMD inspections.

  - The facility has had no citizen complaints filed.

  - The facility has had one Notice to Comply (NC) issued.

    - Notice to Comply (NC D21311), issued 11/20/2015
      Provide explanation/fix to incorrect MDPs, submit CERE form, QCERs, & APEP for MDPs corrections.

      Compliance Status: In compliance.

  - The facility has had two Notices of Violation (NOV) issued.

    - Notice of Violation (NOV P62077) issued 11/4/2016
      Inaccurate QCER/APEP, violated Title V facility permit condition, late daily electronic report, failed to report Process Unit electronic report, and failed to calculate MDP.

      The Title V facility permit condition violation was that Turbine No. 2 exceeded the facility permit condition A99.3 limit of 2 ppm NOx on 2/3/2016 at 7:00 hr. However, the turbine was in compliance with the 2 ppm NOx limit the following hour.

      Compliance Status: In compliance.

    - Notice of Violation (NOV P62087) issued 12/1/2017
      Failure to submit a 1st quarter QCER for the 2016 Compliance Year by October 31, 2016.

      Compliance Status: In compliance.

  The facility is currently in compliance with all applicable rules and regulations.

- ***Rule 1303(b)(5)-Major Polluting Facilities***
- ***Rule 2005(g)—Additional Federal Requirements for Major Stationary Sources***

Rule 1303(b)(5)--In addition to the above requirements, any new major polluting facility or major modification at an existing major polluting facility shall comply with the following requirements, Rule 1305(A) – (D).

Rule 2005(g)—The Executive Officer shall not approve the application for a Facility Permit or an Amendment to a Facility Permit for a new, relocated or modified major stationary source, unless the applicant complies with Rule 2005(g)(1) – (g)(4).

- Rule **1302(s)** defines *major polluting facility* to mean any facility located in the South Coast Air Basin (SOCAB) which emits or has the potential to emit the following amounts or more: VOC, 10 tpy; NOx, 10 tpy; SOx, 70 tpy; PM_{10}, 70 tpy, CO 50 tpy.

- Rule **1302(r)** and **Rule 2005(c)(44)** define *major modification* to mean any modification at an existing major polluting facility that will cause the facility's potentials to emit to increase: (1) 1 lb/day or more of NOx or VOC for a facility located in the South Coast Air Basin; (2) 40 tpy or more of SOx; (3) 15 tpy or more of PM_{10}; or (4) 50 tpy or more of CO.

  Pursuant to *Table 18 - New Source Review Major Polluting Facility Applicability* above, the MGS is a major polluting facility because the current PTEs for NOx and VOC are greater than the respective major source thresholds.

  Table 16 - Facility Maximum Annual Emissions, Post-Modification above shows the facility potential to emit for SOx will increase by 0.08 tpy, which is less than the 70 tpy threshold. The facility potential to emit for NOx, however, will increase by 0.66 tpy or 3.62 lb/day which is greater than the 1 lb/day threshold for major modification.

  (0.66 tpy NOx)(2000 lb/ton)(yr/365 day) = 3.62 lb/day NOx > 1 lb/day threshold

  As the MGS is a major facility and the turbine upgrade project will be a major modification, the following provisions are applicable.

  - ***Rule 1303(b)(5)(A) – Alternative Analysis***
  - ***Rule 2005(g)(2)—Alternative Analysis***
  - ***Rule 1303(b)(5)(D) – Compliance through CEQA***
  - ***Rule 2005(g)(3)—Compliance through CEQA***

  Rule 1303(b)(5)(A) requires an analysis of alternative sites, sizes, production processes and environmental control techniques, and a demonstration that the benefits of the proposed project outweigh the environmental and social costs associated with that project. Rule 1303(b)(5)(D) specifies the requirements of subparagraph (b)(5)(A) may be met through

compliance with CEQA. Rule 2005(g)(2) requires an analysis of alternative sites, sizes, production processes and environmental control techniques for the proposed source which demonstrates that the benefits of the proposed source significantly outweigh the environmental and social cost imposed as a result of its location, construction, or modification. Rule 2005(g)(3) indicates the requirements of paragraph (g)(2) may be met through compliance with CEQA.

Since the MGS is an existing facility applying to install the turbine upgrade on the existing turbines to increase efficiency and applying to increase the operating schedule, the analysis of alternative sites, sizes, production processes, and environmental controls is not applicable.

- ***Rule 1303(b)(5)(B) – Statewide Compliance***
- ***Rule 2005(g)(1) – Statewide Compliance***

Rule 1303(b)(5)(B) requires a demonstration that all major stationary sources are owned or operated by such person in the state are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Rule 2005(g)(1) requires the applicant to certify that all other major stationary sources in the state which are controlled by the applicant are in compliance or on a schedule for compliance with all applicable federal emission limitations or standards.

The MGS is the only facility in the state which is controlled by Bicent. The significant Title V revision application, A/N 598925, included a Form 500-A2—Title V Application Certification. The form was signed by Douglas Halliday, Chief Operating Officer, on 11/9/17. However, the form was filled out incorrectly and certified compliance with *Item 1--For Initial, Permit Renewal, and Administrative Application Certification*, rather than the required *Item 2a--For Permit Revision Application Certifications*. (*Item 2a* certifies: "The equipment or devices to which this permit revision applies, will in a timely manner comply with all applicable requirements identified in Section II and Section III of Form 500-CA.") Bicent Response Letter, 10/20/18, item 16 indicated a revised Form 500-A2 was attached, but the attachment was missing. Bicent Response Letter, 1/23/19, item 16 provided the form via FedEx.

- ***Rule 1303(b)(5)(C) –Protection of Visibility***
- ***Rule 2005(g)(4)—Protection of Visibility***

Rule 1303(b)(5)(C) requires a modeling analysis for plume visibility if the net emission increases from a new or modified sources exceed 15 tpy of PM_{10} or 40 tpy of NOx; and the location of the source, relative to the closest boundary of a specified Federal Class I area, is within the distance specified in Table C-1 of the rule. Rule 2005(g)(4) imposes the same requirements for NOx, with the Federal Class I areas and distances listed in Table 4-1 of the rule (same as Table C-1). From *Table 16 - Facility Maximum Annual Emissions, Post-*

Modification above, the net increase is 0 tpy of PM_{10} emissions and 0.66 tpy NOx emissions. Thus Bicent will not be subject to this provision.

Rule 1313—Permits to Operate

(g) Emission Limitation Permit Conditions
Every permit shall have the following conditions:

(1) Identified BACT conditions
(2) Monthly maximum emissions from the permitted source

Analysis:
For the turbines:

BACT—Conditions A195.1, A195.2, and A195.3 set forth the BACT limits for NOx, CO, and VOC, respectively.

Monthly Emissions—Condition A63.3 sets forth the monthly limits for CO, PM_{10}, $PM_{2.5}$, VOC, and SOx. The limits are based on the combined emissions from the two turbines.

Rule 1325—Federal PM2.5 New Source Review Program

Rule 1325 was adopted on June 3, 2011 to incorporate U.S. EPA requirements for PM2.5 into Regulation XIII – New Source Review (NSR). The rule mirrors federal requirements, including offset ratios, Lowest Achievable Emission Rate (LAER) compliance, and control of PM2.5 precursors.

Rule 1325 was amended on 12/5/14 to incorporate administrative changes to definitions, provisions and exclusions, based on comments received from the U.S. EPA regarding SIP approvability of Rule 1325. The amended rule was approved into the California State Implementation Plan on 5/1/15. The applicable requirements of 40 CFR Part 51, Appendix S, were necessary for permitting actions until Rule 1325 became SIP-approved.

Rule 1325 was amended on 11/4/16 to establish appropriate major stationary source thresholds for direct $PM_{2.5}$ and $PM_{2.5}$ precursors, including VOC and ammonia, in order to align with the recent reclassification of the South Coast Basin from a "moderate" $PM_{2.5}$ nonattainment area to a "serious" nonattainment area and with U.S. EPA's Fine Particulate Matter National Ambient Air Quality Standards implementation rule. The amendments were intended to facilitate SIP approval of the regulations. The amendment added ammonia and VOC as precursors to $PM_{2.5}$, per Clean Air Act Subpart 4 requirements. The major polluting facility thresholds were lowered from 100 tons per year per pollutant to 70 tons per year per pollutant. These amendments will be effective after August 14, 2017 or upon the effective date of EPA's approval of these amendments to this rule, whichever is later. US EPA's Fine Particulate Matter National Ambient Air Quality Standards implementation rule states an area can rely on SIP-approved $PM_{2.5}$ New Source Review rule until the new rule is approved. 81 Fed Reg 58009 (August 24, 2016). US EPA's final implementation rule became effective on 10/24/16.

Rule 1325 was amended on 1/4/19 to address a deficiency in the 11/4/16 amendment in which the definition of "precursors" was expanded to add VOC and ammonia (NH3) to the existing list of PM2.5 precursors (oxides of nitrogen and sulfur dioxide), but the definition of "regulated NSR pollutant" was not expanded to explicitly reference VOC and NH3. The 1/4/19 amendment addresses the deficiency by referencing "precursors" in the definition of "regulated NSR pollutant." In addition, the rule language was clarified and outdated language removed.

The relevant provisions of Rule 1325, as amended 1/4/19, are presented below, followed by the rule analysis.

(a) This rule applies to any new major polluting facility, major modifications to a major polluting facility, and any modification to an existing facility that would constitute a major polluting facility in and of itself that will emit PM2.5 or its precursors, as defined herein; located in areas federally designated pursuant to Title 40 of the Code of Federal Regulations (40 CFR) 81.305 as non-attainment for $PM_{2.5.}$

With respect to major modifications, this rule applies on a pollutant-specific basis to emissions of $PM_{2.5}$ and its precursors, for which (1) the source is major, (2) the modification results in a significant increase, and (3) the modification results in a significant net emissions increase.

(b) Definitions
For the purposes of this rule, the definitions in Title 40 CFR 51.165(a)(1) shall apply, unless the same term is defined below, then the defined term below shall apply:

(1) BASELINE ACTUAL EMISSIONS means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with the following:
(A) For any existing electric utility steam generating unit, baseline actual emissions means the average rate, in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction of the project. The Executive Officer shall allow the use of a different time period upon a determination that it is more representative of normal source operation….

(3) MAJOR MODIFICATION means:
(A) Any physical change in or change in the method of operation of a major polluting facility that would result in: a significant emissions increase of a regulated NSR pollutant; and a significant net emissions increase of that pollutant from the major polluting facility.

(4) MAJOR POLLUTING FACILITY means, on a pollutant specific basis, any emissions source located in areas federally designated pursuant to 40 CFR 81.305 as non-attainment for $PM_{2.5}$, including the South Coast Air Basin (SOCAB) which has actual emissions of, or the potential to emit $PM_{2.5}$, or its precursors at or above 70 tons per year per pollutant. A facility is considered to be a major polluting facility only for the specific pollutant(s) with a potential to emit at or above the levels specified.

(9) PRECURSORS mean, for the purposes of this rule, NOx, sulfur dioxide (SO_2), volatile organic compounds (VOC), and ammonia (NH3).

(13) SIGNIFICANT means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Pollutant	**Emissions Rate (tons per year)**
NOx	40
SO2	40
VOC	40
NH3	40
PM2.5	10

(c) Requirements

(1) The Executive Officer shall deny the Permit for a new major polluting facility; or major modification to a major polluting facility; or any modification to an existing facility that would constitute a major polluting facility in and of itself, unless each of the following requirements is met:

(A) Lowest Achievable Emission Rate (LAER**)** is employed for the new or relocated source or for the actual modification to an existing source; and

(B) Emission increases shall be offset at an offset ratio of 1.1:1 for $PM_{2.5}$ and the ratio required in Regulation XIII or Rule 2005 for NOx and SO_2 as applicable; and

(C) Certification is provided by the owner/operator that all major sources, as defined in the jurisdiction where the facilities are located, that are owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in the State of California are subject to emission limitations and are in compliance or on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act; and

(D) An analysis is conducted of alternative sites, sizes, production processes, and environmental control techniques for such proposed source and demonstration made that the benefits of the proposed project outweigh the environmental and social costs associated with that project.

(h) Test Methods

For the purpose of this rule only, testing for point sources of $PM_{2.5}$ shall be in accordance with U.S. EPA Test Methods 201A and 202.

Analysis:

As summarized in the table below, Rule 1325 is not applicable to NOx, SO_2, VOC, NH_3, and $PM_{2.5}$ for the following reasons:

(1) The post-modification MGS is not a new major polluting facility because it is a modification of an existing facility.

(2) The turbine upgrade modification is not a major modification to a major polluting facility. As shown in the table below, the pre-modification MGS is not a major polluting facility because it is not a major source for NOx, SO_2, VOC, NH_3, and $PM_{2.5}$ as the potential to emit for each pollutant is less than 70 tpy. Therefore, it is not necessary to evaluate whether the turbine upgrade modification is a major modification that would result in a significant potential emissions increase and a significant net emissions increase. Significant means an increase that would equal or exceed: NOx, 40 tpy; SOx, 40 tpy; VOC, 40 tpy, NH_3, 40 tpy; or $PM_{2.5}$, 10 tpy.

(3) The turbine upgrade modification to the existing pre-modification MGS does not constitute a major polluting facility in and of itself because the net increases for NOx, SO_2, VOC, NH_3, and $PM_{2.5}$ for each pollutant is less than 70 tons. ($PM_{2.5}$ emissions are conservatively assumed to be the same as PM_{10} emissions.)

Table 34 - Rule 1325 Applicability

	NOx	**SO_2**	**VOC**	**NH_3**	**$PM_{2.5}$**
Pre-Modification MGS, Potential to Emit (PTE), TPY (*Table 15*)	40.65	1.28	19.42	33.20	29.26
Major Source for Particular Pollutant?	No, PTE is less than 70 tpy.	No, PTE is less than 70 tpy.	No, PTE is less than 70 tpy.	No, PTE is less than 70 tpy.	No, PTE is less than 70 tpy.
Post-Modification MGS Potential to Emit, TPY (*Table 16*)	41.31	1.36	19.42	33.20	29.26
Pre-Modification MGS Actual Emissions (2016 & 2017 Avg) TPY (per Annual Emissions Reporting)	$(19.821_{2016} + 19.702_{2017}) /2 = 19.76$	$(0.757_{2016} + 0.765_{2017})/ 2 = 0.761$	$(4.416_{2016} + 4.461_{2017})/ 2 = 4.44$	$[(49262.867_{2016} + 49771.132_{2017})/ 2]$ x ton/2000 lb = 24.76	$(21.911_{2016} + 22.058_{2017})/ 2 = 21.98$
Net Emissions Increase (Post-Modification MGS PTE – Pre-Modification MGS actual)	41.31 – 19.76 = 21.55	1.36 – 0.761 = 0.60	19.42 – 4.44 = 14.98	33.20 – 24.76 = 8.44	29.26 – 21.98 = 7.28
If Pre-Modification MGS is not a major facility for a particular pollutant, does the Post-Modification MGS constitute a modification that would constitute a major polluting facility in and of itself?	No, net increase is less than 70 tpy.	No, net increase is less than 70 tpy.	No, net increase is less than 70 tpy.	No, net increase is less than 70 tpy.	No, net increase is less than 70 tpy.
Rule 1325 Applicable?	No	No	No	No	No

Rule 1401—New Source Review of Toxic Air Contaminants, as amended 9/1/17
Rule 2005(i)–Rule 1401 (RECLAIM)

Rule 1401 specifies limits for maximum individual cancer risk (MICR), cancer burden, and noncancer acute and chronic hazard index (HI) from new permit units, relocations, or modifications to existing permit units which emit toxic air contaminants listed in Table I of this rule. The rule establishes allowable risks for permit units requiring new permits pursuant to Rules 201 or 203. Rule 2005(i) requires compliance with Rule 1401 for NOx emissions.

The relevant requirements are presented below.

(d) Requirements

The Executive Officer shall deny the permit to construct a new, relocated or modified permit unit if emissions of any toxic air contaminant listed in Table I may occur, unless the applicant has substantiated to the satisfaction of the Executive Officer all of the following:

(1) MICR and Cancer Burden
The cumulative increase in MICR which is the sum of the calculated MICR values for all toxic air contaminants emitted from the new, relocated or modified permit unit will not result in any of the following:
(A) an increased MICR greater than one in one million ($1.0 \times 10^{-6)}$ at any receptor location, if the permit unit is constructed without T-BACT;
(B) an increased MICR greater than ten in one million (10×10^{-6}) at any receptor location, if the permit unit is constructed with T-BACT;
(C) a cancer burden greater than 0.5.

(2) Chronic Hazard Index
The cumulative increase in total chronic HI for any target organ system due to total emissions from the new, relocated or modified permit unit owned or operated by the applicant for which applications were deemed complete on or after the date when the risk value for the compound is finalized by the state Office of Environmental Health Hazard Assessment (OEHHA) will not exceed 1.0 at any receptor location.

(3) Acute Hazard Index
The cumulative increase in total acute HI for any target organ system due to total emissions from the new, relocated or modified permit unit owned or operated by the applicant for which applications were deemed complete on or after the date when the risk value for the compound is finalized by OEHHA will not exceed 1.0 at any receptor location.

(e) Risk Assessment Procedures
(1) The Executive Officer shall periodically publish procedures for determining health risk assessments under this rule. To the extent possible, the procedures will be consistent with the most recently adopted policies and procedures of the state OEHHA.

On March 6, 2015, the California Office of Environmental Health Hazard Assessment (OEHHA) approved the Air Toxics Hot Spots Program Guidance Manual for Preparation of Risk Assessments (2015 OEHHA Guidelines). On June 5, 2015, the SCAQMD approved amendments to Rule 1401 to revise definitions and risk assessment procedures to be consistent with the 2015 OEHHA Guidelines. These updated guidelines take into account recent scientific advances which have found greater risk to children when they are exposed to cancer causing compounds.

1. **A/N 598922—Modification to Turbine No. 1**
2. **A/N 598923—Modification to Turbine No. 2**

A. Initial: A/N 394164 & 394165—FDOC

For the FDOC, the applicant performed a modeling analysis using the ISCST3 model to determine the one-hour and annual average concentration of toxic air contaminants (TACs) for the operation of the facility, consisting of the two CTs and the cooling tower. The combustion of natural gas in the two CTs produces TACs. The drift of reclaimed water from the cooling tower produces TACs. The emergency ICE for the firewater pump is exempt pursuant to Rule 1401(g)(1)(F), which exempts emergency ICEs exempted under Rule 1304. The potential health risks were assessed using the ACE 2588 (Assessment of Chemical Exposure for AB2588) risk assessment model (Version 93288), which is consistent with CAPCOA Risk Assessment Guidelines (CAPCOA).

Based on preliminary emissions modeling of startup, normal operation, and shutdown scenarios, the applicant determined that the scenario resulting in the highest hourly and annual TAC emissions was determined to occur when both CTGs and duct burners, and the cooling tower are operating at full load for 8760 hours per year.

Note: The CEC required the applicant to provide air dispersion modeling and an HRA for the fire pump. Both analyses were based on 200 hours of operation. (The FDOC did not include a discussion of the fire pump modeling required by the CEC.)

B. Post-Modification: A/N 598922 & A/N 598923—Turbine Upgrade

The applicant provided health risk assessment (HRA) modeling using the California Air Resources Board's (ARB) *Hot Spots Analysis Reporting Program* (HARP) model (ADMRT 17052) , which incorporates methodology presented in the 2015 OEHHA Guidelines. SCAQMD HRA procedures require HARP to be used in Tier 4 risk assessments.

On p. 2-9 of the Application, *Table 27—MGS Health Risk Assessment Summary* provides a condensed summary of HRA results. The table provides facility-wide cancer risks with and without the fire pump, chronic health indices with and without the fire pump, and acute hazard index. The table also provides the cancer risk and chronic hazard index for the fire pump only.

SCAQMD AI Letter, 5/1/18, item 9.c.i. requested: "For the purpose of Rule 1401 compliance, please provide cancer risks, chronic hazard indices, and acute hazard indices for the sensitive/residential receptors and the worker receptors for each turbine as required by Rule 1401." Item 9.c.ii requested: "For the purpose of CEQA analysis for CEC, please provide facility-wide cancer risks, chronic hazard indices, and acute hazard indices for

sensitive/residential and worker receptors." Bicent Response Letter, 5/17/18, item 9.c.i provided the health risks values for the residential and worker sensitive receptors by turbine, and item 9.c.ii provided the facility-wide risk values for all sources included in the HRA for the sensitive residential and worker receptors in *Table 2 Health Risk Values by Turbine [and Facility]* in the letter.

SCAQMD AI Letter, item 6.d.i, requested health risk assessments for the cooling tower. Although the cooling tower is exempt from permitting pursuant to Rule 219(d)(3)(B), Rule 219(s) provides an exception from the permit exemption when the equipment exceeds the health risk value limits in Rule 1401. Bicent Letter, 10/20/18, item 9.c.iii, provided the health risks values for the residential and worker sensitive receptors for each cell in *Table 3 Health Risk Values by Cell for the Cooling Tower.*

- *Turbines*
  P. 12 of the Air Quality Modeling Protocol, October 2017 in Attachment 6 of the Application states: "For the HRA analyses, the annual average operating condition (100% load at 59 °F) [Scenario S14] will be assessed."

  Bicent Response Letter, 10/20/18, item 9.a.i – ii indicated that Scenario S15 (100% load, 65 ºF ambient) was used to represent the stack parameters for both the 1-hour acute and the annual chronic and cancer impact analysis. Scenario S13 (100% load, 38 °F ambient) was used to calculate the fuel use to determine the maximum hourly emissions but Scenario S15 was used to model the 1-hour acute impacts as the overall acute analyses from natural gas turbines is often several orders of magnitude less than the acute significance level of 1.0. [Bicent Response Letter, 1/23/19, item 9.a.ii clarified this means that the slight difference in stack parameters (exit temperature and exit velocity) between Scenarios S13 and S15 would not would not result in the project becoming significant as the maximum acute impact of 0.0059 (at receptor 2612) is several orders of magnitude less than the significance level of 1.0.] Scenario S15 (100% load at 65 ºF) was used to calculate the fuel use to determine the maximum annual emissions and stack parameters based on the long-term exposure (30 year) requirements for the chronic and cancer impact analyses.

Table 35 - Modeled Stack Parameters for HRA for a Turbine

Parameter	Hourly Impacts Scenario S15--100% Load, 38.0 °F	Annual Impacts Scenario S15—100% Load, 65.0 °F
Stack Diameter (m)	3.6576	3.6576
Stack Height (m)	33.53	33.53
Stack Temp (°K)	378.15	378.15

Stack Velocity (m/s)	13.743	13.743

Table 2 Health Risk Values by Turbine [and Facility] provided by Bicent Response Letter, 5/17/18, items 9.c.i and 9.c.ii, is reproduced below. The project health risk assessment is provided in support of the CEC's CEQA analysis.

Table 2 Health Risk Values By Turbine

Modeling Receptor #	Receptor ID #	Receptor Type	Receptor Sub_ID	Turbine 1 Cancer Risk	Turbine 1 Chronic HI	Turbine 1 Acute HI	Turbine 2 Cancer Risk	Turbine 2 Chronic HI	Turbine 2 Acute HI	Facility Wide Risk Values (1) Cancer Risk	Facility Wide Risk Values (1) Chronic HI	Facility Wide Risk Values (1) Acute HI
8029	1	Residences	SSW	3.29E-07	4.47E-04	1.25E-03	3.37E-07	4.58E-04	1.29E-03	8.25E-07	1.01E-03	2.54E-03
8030	2		S	2.29E-07	3.10E-04	6.86E-04	2.31E-07	3.14E-04	7.04E-04	5.60E-07	6.88E-04	1.39E-03
8031	3		ESE	2.72E-07	3.70E-04	3.94E-04	2.78E-07	3.77E-04	3.90E-04	6.16E-07	8.12E-04	7.84E-04
8032	4		NE	1.03E-07	1.39E-04	2.97E-04	1.02E-07	1.38E-04	2.95E-04	2.21E-07	3.00E-04	5.92E-04
8033	5		NNE	1.08E-07	1.46E-04	3.23E-04	1.07E-07	1.46E-04	3.24E-04	2.34E-07	3.16E-04	6.47E-04
8034	6		N	1.06E-07	1.43E-04	2.40E-04	1.05E-07	1.43E-04	2.40E-04	2.24E-07	3.08E-04	4.80E-04
8035	7		NW	1.03E-07	1.40E-04	2.31E-04	1.03E-07	1.40E-04	2.29E-04	2.27E-07	3.05E-04	4.60E-04
8036	8		W	1.13E-07	1.53E-04	2.00E-04	1.13E-07	1.53E-04	1.99E-04	2.49E-07	3.32E-04	3.99E-04
8037	9		SW	1.12E-07	1.51E-04	2.16E-04	1.12E-07	1.52E-04	2.15E-04	2.43E-07	3.28E-04	4.31E-04
8038	10		N	8.85E-07	1.20E-03	2.71E-03	8.73E-07	1.19E-03	2.64E-03	2.07E-06	2.69E-03	5.35E-03
8039	11		E	1.09E-06	1.47E-03	2.76E-03	1.11E-06	1.50E-03	2.78E-03	3.53E-06	3.68E-03	5.54E-03
8040	12		S	6.66E-07	9.04E-04	2.63E-03	6.77E-07	9.19E-04	2.65E-03	1.67E-06	2.05E-03	5.28E-03
8041	13	Worker	W	5.85E-07	7.93E-04	2.35E-03	5.84E-07	7.93E-04	2.36E-03	1.43E-06	1.81E-03	4.71E-03
8042	14		NE	9.56E-07	1.30E-03	2.60E-03	9.37E-07	1.27E-03	2.65E-03	2.26E-06	2.91E-03	5.25E-03
8043	15		NW	5.74E-07	7.79E-04	2.25E-03	5.66E-07	7.69E-04	2.14E-03	1.39E-06	1.78E-03	4.39E-03
8044	16		SW	3.84E-07	5.21E-04	1.66E-03	3.91E-07	5.30E-04	1.59E-03	9.56E-07	1.18E-03	3.25E-03
8045	17		SE	7.10E-07	9.64E-04	1.87E-03	7.91E-07	1.07E-03	1.96E-03	1.92E-06	2.27E-03	3.84E-03

(1) all sources included in the HRA.

(2) none of the sensitive receptors noted above represent the MIR, see the data below dated 1/30/18 for the MIR data.

(3) MIR data below is the facility-wide data for all sources at the site

MIR Data		Cancer Risk	Chronic HI	Acute HI
		3.97E-06	0.0048	0.0059
	Recp #	2612	2671	2381

- <u>*Cooling Tower*</u>
  Table 3 Health Risk Values by Cell for the Cooling Tower provided by Bicent Letter, 10/20/18, item 9.c.iii, is reproduced below.

Table 3 Health Risk Values by Cell for the Cooling Tower

Modeling	Receptor ID	Receptor	Receptor	Cell 1			Cell 2			Cell 3		
Receptor #	#	Type	Sub_ID	Cancer Risk	Chronic HI	Acute HI	Cancer Risk	Chronic HI	Acute HI	Cancer Risk	Chronic HI	Acute HI
8029	1		SSW	1.90E-10	2.15E-05	5.93E-07	1.90E-10	2.15E-05	3.69E-07	1.90E-10	2.15E-05	3.89E-07
8030	2		S	1.19E-10	1.34E-05	2.50E-07	1.19E-10	1.35E-05	3.31E-07	1.20E-10	1.35E-05	3.34E-07
8031	3		ESE	1.48E-10	1.67E-05	1.88E-07	1.49E-10	1.68E-05	1.89E-07	1.50E-10	1.69E-05	1.89E-07
8032	4		NE	5.55E-11	6.27E-06	1.05E-07	5.54E-11	6.26E-06	1.05E-07	5.52E-11	6.24E-06	1.05E-07
8033	5	Residences	NNE	5.66E-11	6.40E-06	1.23E-07	5.67E-11	6.41E-06	1.24E-07	5.67E-11	6.41E-06	1.25E-07
8034	6		N	5.69E-11	6.43E-06	9.64E-08	5.69E-11	6.43E-06	9.70E-08	5.69E-11	6.43E-06	9.76E-08
8035	7		NW	5.71E-11	6.46E-06	1.05E-07	5.69E-11	6.43E-06	1.05E-07	5.67E-11	6.41E-06	1.05E-07
8036	8		W	6.22E-11	7.04E-06	7.71E-08	6.20E-11	7.01E-06	7.76E-08	6.18E-11	6.99E-06	7.81E-08
8037	9		SW	6.09E-11	6.89E-06	7.86E-08	6.08E-11	6.87E-06	7.84E-08	6.06E-11	6.85E-06	7.82E-08
8038	10		N	6.87E-10	7.77E-05	1.10E-06	6.90E-10	7.80E-05	1.10E-06	6.91E-10	7.81E-05	1.14E-06
8039	11		E	1.13E-09	1.28E-04	2.17E-06	1.16E-09	1.32E-04	2.20E-06	1.19E-09	1.35E-04	1.93E-06
8040	12		S	4.26E-10	4.82E-05	3.35E-06	4.51E-10	5.10E-05	3.35E-06	4.84E-10	5.47E-05	3.47E-06
8041	13	Worker	W	4.94E-10	5.58E-05	1.05E-06	4.89E-10	5.53E-05	1.08E-06	4.82E-10	5.45E-05	1.08E-06
8042	14		NE	7.81E-10	8.83E-05	1.27E-06	7.58E-10	8.58E-05	1.41E-06	7.56E-10	8.55E-05	1.54E-06
8043	15		NW	5.31E-10	6.01E-05	1.19E-06	5.11E-10	5.78E-05	1.15E-06	4.90E-10	5.55E-05	1.11E-06
8044	16		SW	2.59E-10	2.93E-05	6.81E-07	2.56E-10	2.90E-05	1.72E-06	2.55E-10	2.89E-05	1.83E-06
8045	17		SE	4.03E-10	4.55E-05	5.67E-07	4.15E-10	4.69E-05	5.85E-07	4.28E-10	4.84E-05	6.04E-07

SCAQMD Modeling Review Memo

Due to time constraints, SCAQMD Modeler Sam Wang re-ran the AERMOD and HRA using the correct meteorological data, ozone data, receptors, control pathways, source groups, background air quality monitoring data for all operating scenarios. SCAQMD used the most recently available and meteorologically-appropriate 5-year data set from Downtown LA/USC station and re-ran HARP with all receptor grids (including the additional receptors on the southern project site due to the fence line change, Petition to Amend for Site Delineation, CEC, 2/4/2019) for the project's HRA. The project's health risk impacts are listed in the table below. The health risks for the entire proposed project are less than the Rule 1401 cancer and non-cancer permit limits of ten in one million (1.0×10^{-05}) with T-BACT and hazard index of 1.0, respectively.

Table 37/38
SCAQMD's Health Risk Impacts

Total Project (Entire Facility)							
Sensitive	0.88 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	3.96 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Receptor Type	**Cancer Risk**	**Chronic Hazard Index**	**Acute Hazard Index**	**Cancer Risk Threshold[1]**	**Chronic HI Threshold**	**Acute HI Threshold**	**Exceeds Any Threshold?**
Turbine 1							
Sensitive	0.34 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	1.09 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Turbine 2							
Sensitive	0.35 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	1.16 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Firewater Pump							
Sensitive	0.5 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No

Worker	1.86 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No

Colling Tower Cell 1							
Sensitive	0.0002 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	0.001 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Colling Tower Cell 2							
Sensitive	0.0002 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	0.001 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Colling Tower Cell 3							
Sensitive	0.0002 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	0.001 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No

[1] For permit units without T-BACT, the increased MICR cannot be greater than the Rule 1401 cancer risk threshold of one in one million (1.0×10^{-6}). For permit units with T-BACT, the increased MICR cannot be greater than the Rule 1401 cancer risk threshold of ten in one million (1.0×10^{-5}).

- Best Available Control Technology For Toxics (T-BACT) for Combustion Turbines

  The *Overview* of the *SCAQMD Best Available Control Technology Guidelines*, amended December February 2, 2018, indicates that, as of the publication date of these guidelines, there is currently no requirement for SCAQMD to publish T-BACT guidelines and T-BACT must be established during the permitting process on a case-by-case basis.

  Rule 1401(c)(2) defines T-BACT to mean the most stringent emissions limitation or control technique which: (A) has been achieved in practice for such permit unit category or class of source; or (B) is any other emissions limitation or control technique, including process and equipment changes of basic and control equipment, found by the Executive Officer to be technologically feasible for such class or category of sources, or for a specific source.

  The analysis below shows that T-BACT for combustion turbines is determined to be an oxidation catalyst. Thus the MICR limit is ten in one million for each turbine, because each turbine is equipped with a CO oxidation catalyst.

  The final maximum achievable control standard (MACT) for stationary combustion turbines was published on March 5, 2004 (69 FR 10512), and subsequently codified at 40 CFR Part 63, Subpart YYYY—National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Stationary Combustion Turbines. The determination that an oxidation catalyst is T-BACT for combustion turbines is supported by EPA's assessment that it is not aware of any add-on control devices which can reduce organic HAP emissions to levels lower than those resulting from the application of oxidation catalyst systems (69 FR 10530).

  Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions. This NESHAP implements section 112(d) of the Clean Air Act (CAA) by requiring all major sources to meet HAP emission standards reflecting the application of the maximum achievable control technology for combustion turbines. Stationary combustion turbines were identified as major sources of hazardous air pollutants emissions, such as formaldehyde, toluene, benzene, and acetaldehyde.

  Subpart YYYY requires an affected new or reconstructed stationary combustion turbine to comply with the emission limitation to reduce the concentration of formaldehyde in the exhaust to 91 parts per billion by volume (ppbvd) or less, at 15 percent O_2. Affected turbines are lean premix gas-fired, lean premix oil-fired, diffusion flame gas-fired, and diffusion flame oil-fired stationary combustion turbines. Oil-fired stationary combustion turbines must comply with the emissions limitations and operating limitations upon startup. Gas-fired stationary combustion turbines must comply with the Initial Notification requirements set forth in §63.6145 but need not comply with any other requirement of this subpart until EPA takes final action to require compliance. Subpart YYYY was amended on August 18, 2004 (69 FR 51184) to stay the effectiveness of the standards in the lean premix gas-fired and diffusion flame subcategories, because, on April 7, 2004, EPA had

proposed to delist four subcategories, including lean premix gas-fired turbines, from the Stationary Combustion Turbines source category (69 FR 18327). The delisting process remains pending.

EPA explained that, for new sources, the MACT floor is defined as the emission control that is achieved in practice by the best controlled similar source. (69 FR 10530) EPA considered using a surrogate for all organic HAP emissions in order to reduce the costs associated with monitoring while at the same time being relatively sure that the pollutants the surrogate is supposed to represent are also controlled. EPA investigated the use of formaldehyde concentration as a surrogate because formaldehyde is the HAP emitted in the highest concentrations from stationary combustion turbines. Formaldehyde, toluene, benzene, and acetaldehyde account for essentially all the mass of HAP emissions from the stationary combustion turbine exhaust, and emissions data show that these pollutants are equally controlled by an **oxidation catalyst**. EPA reviewed testing information conducted on a diffusion flame combustion turbine equipped with an **oxidation catalyst** control system, emissions tests conducted on reciprocating internal combustions engines equipped with **oxidation catalysts**, and **catalyst** performance information obtained from a **catalyst** vendor. EPA concluded that it is appropriate to use formaldehyde as a surrogate for all organic HAP emissions. (69 FR 10530)

For new lean premix gas-fired turbines, EPA reviewed emissions data it had available at proposal, and additional test reports received during the comment period. The best performing turbine is equipped with an **oxidation catalyst**. Based on testing of the formaldehyde concentration from the best performing turbine, the MACT floor for organic HAP for new stationary lean premix gas-fired turbines is, therefore, an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen. (69 FR 10530) No beyond-the-floor regulatory alternatives were identified for new lean premix gas-fired turbines. EPA is not aware of any add-on control devices which can reduce organic HAP emissions to levels lower than those resulting from the application of **oxidation catalyst** systems. EPA, therefore, determined that MACT for organic HAP emissions from new stationary lean premix gas-fired turbines is the same as the MACT floor, i.e., an emission limit of 91 ppbvd formaldehyde at 15 percent oxygen. (69 FR 10530)

As discussed in the rule analysis for Subpart YYYY below, this subpart is not applicable to the proposed simple-cycle turbines because the MGS facility will not be a major source for HAP emissions.

Rule 1401.1—Requirements for New and Relocated Facility Near Schools

(b) Applicability
This rule applies to new and relocated, not to existing facilities.

(c) Definitions
(3) EXISTING FACILITY means any facility that:
(A) demonstrates to the satisfaction of the Executive Officer that it had equipment requiring a Permit to Construct/Operate that was in operation prior to November 4, 2005 or

(B) has an application for Permit to Construct/Operate that is deemed complete prior to February 2, 2006.

Bicent is an existing facility because the initial applications for the turbine project were submitted by the original operator, Vernon City, Light & Power Dept. (ID 14502), on 12/7/01. Therefore, this rule is not applicable to the facility.

REGULATION XVII – Prevention of Significant Deterioration

The federal Prevention of Significant Deterioration (PSD) is established to protect deterioration of air quality in those areas that already meet the primary NAAQS. This regulation sets forth preconstruction review requirements for stationary sources to ensure that air quality in clean air areas do not significantly deteriorate while maintaining a margin for future industrial growth. Specifically, the PSD program establishes allowable concentration increases for attainment pollutants due to new or modified emission sources that are classified as major stationary sources.

Effective upon delegation by EPA, this regulation shall apply to preconstruction review of stationary sources that emit attainment air contaminants. On 3/3/03, EPA rescinded its delegation of authority to the SCAQMD. On 7/25/07, the EPA and SCAQMD signed a new "Partial PSD Delegation Agreement." The agreement is intended to delegate the authority and responsibility to the District for issuance of initial PSD permits and for PSD permit modifications where the applicant does not seek to use the emissions calculation methodologies promulgated in 40 CFR 52.21 (NSR Reform) but not included in SCAQMD Regulation XVII. The Partial Delegation agreement did not delegate authority and responsibility to SCAQMD to issue new or modified PSD permits based on Plant-wide Applicability Limits (PALS) provisions of 40 CFR 52.21.

Since this is a partial delegation the facilities in the South Coast Air Basin (SCAB) may either apply directly to EPA for the PSD permit in accordance with the current requirements of 40 CFR Part 52 Subpart 21, or apply to the SCAQMD in accordance with the current requirements of Regulation XVII.

The SCAB has been in attainment for NO_2, SO_2, and CO emissions. In addition, effective 7/26/13, the SCAB has been redesignated to attainment for the 24-hour PM_{10} national ambient air quality standard. Therefore, the attainment air contaminants are NO_2, SO_2, CO, and PM_{10}.

The relevant PSD applicability rule provisions are presented below, followed by the applicability analysis.

- **PSD Applicability Rules**

  Rule 1701—General

  Effective upon delegation by EPA, this regulation shall apply to preconstruction review of stationary sources that emit attainment air contaminants.

  Rule 1701(b)(1) provides: The BACT requirement applies to a net emission increase of a

criteria air contaminant from a permit unit at any stationary source.

Rule 1701(b)(2) provides:

All of the requirements of this regulation apply, except as exempted in Rule 1704, to the following stationary sources:

(A) A new source or modification at an existing source where the increase in potential to emit is at least 100 or 250 tons of attainment air contaminants per year, depending on the source category; or

(B) A significant emission increase at an existing major stationary source; or

(C) Any net emission increase at a major stationary source located within 10 km of a Class I area, if the emission increase would impact the Class I area by 1.0 $\mu g/m^3$, (24-hours average).

Rule 1702—Definitions

(e) Best Available Control Technology (BACT) means the most stringent emission limitation or control technique which:

(1) has been achieved in practice for such permit unit category or class of source. For permit units not located at a major stationary source, a specific limitation or control technique shall not apply if the owner or operator of the proposed sources demonstrates to the satisfaction of the Executive Officer that such limitation or control technique is not attainable for that permit unit; or

(2) is contained in any State Implementation Plan (SIP) approved by the Environmental Protection Agency (EPA) for such permit unit category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer that such limitation or control technique is not presently achievable; or

(3) is any other emission control technique, including process and equipment changes of basic and control equipment, found by the Executive Officer to be technologically feasible and cost-effective for such class or category of sources or for a specific source….

(l) Major Modification means any physical change in the method of operation of a major stationary source that would result in a significant emission increase.

(m) Major Stationary Source means:

(1) one of the following source categories: (1) Fossil fuel-fired steam electric plants of more than 250 million BTU/hr input…; which emits or has the potential to emit 100 tons per year or more of any contaminant regulated by the Act; or

(2) an unlisted stationary source that emits or has the potential to emit 250 tons per year or more of any pollutant regulated by the Act; or

(3) a physical change in a stationary source not otherwise qualifying under paragraph (1) or (2) if a modification would constitute a major stationary source by itself."

(s) Significant Emission Increase means any attainment air contaminant for which the net cumulative emission increase of that air contaminant from a major stationary source is greater than the amount specified as follows:

Contaminant	Emissions Rate (tpy)
Carbon Monoxide	100
Sulfur Dioxide	40
Nitrogen Oxides	40
PM_{10}	15

Rule 1706—Emissions Calculations

This rule shall be used as the basis for calculating applicability to Regulation XVII as delineated in Rule 1703(a).

(c) Calculation of Emissions for Threshold Determination

This paragraph provides the method for calculating the emission increases and reductions associated with a stationary source, as described in paragraph (a).

(1) Emission increases or reductions from permit units at a stationary source shall be calculated as follows:

(A) The emissions for new permit units and the new emissions for modified or relocated permit units shall be calculated from permit conditions for permits to construct and operate issued pursuant to an EPA approved version of this regulation which directly limit the emissions or, when no such conditions are imposed, from:

(i) the maximum rated capacity; and

(ii) twenty-four hours of operation per day; and

(iii) the actual materials processed; and

(B) The emissions before modification, relocation, or removal from service shall be calculated from:

(i) the sum of actual emissions, as determined from company records, which have occurred during the two-year period immediately preceding date of permit application, or a different two year time period within the past five (5) years upon a determination by the Executive Officer that it is more representative of normal source

operation, except annual emission declarations pursuant to Rule 301 may be used if less than the actual emissions as determined above; and

(ii) the total emissions in those two years shall be calculated on an annual basis.

PSD Applicability Analysis for Criteria Pollutants

The District is presently in attainment for the primary NAAQS for NO_2, SO_2, CO, and PM_{10} (South Coast Basin).

The first step is to determine whether the major source threshold for Bicent is 100 or 250 tpy. The twenty-eight source categories subject to the 100 tpy threshold are listed in Rule 1702(m)(1). The list includes a "fossil fuel-fired steam electric plants of more than 250 million BTU/hr." A fossil fuel-fired steam electric plant refers to a plant with combined-cycle turbine(s). As discussed for *Subpart KKKK—NSPS for Stationary Gas Turbines* below, the peak load is the rating at Independent System Operator (ISO) standard conditions (59 ºF, 60% relative humidity, 1 atm). These conditions correspond to Case S14 (100% load, 59 ºF ambient) for which the current rating is 443.56 MMBtu/hr per turbine (from Appendix B-5 of Application for P/C, A/N 394164). As Bicent is a combined-cycle electric plant rated at 887.12 MMBtu/hr (2 turbines x 443.56 MMBtu/hr per turbine), the 100 tpy threshold limit is applicable. This is in contrast to simple-cycle turbines (no steam) for which the 250 tpy threshold is applicable.

PSD Applicability Analysis:

As summarized in the table below for the first two criteria, Bicent is not subject to PSD review for NOx, SO_2, PM_{10} and CO for the following reasons:

(A) The turbine upgrade modification at an existing source will not result in an increase in potential to emit of at least 100 tpy for NOx, SO_2, PM_{10}, or CO.

(B) The turbine upgrade modification will not result in a significant emission increase at an existing major stationary source. As shown in the table below, the pre-modification MGS is not an existing major stationary source because the PTE is less than 100 tpy for NOx, SO_2, $PM_{10,}$ and CO. If a source is a major source for any one regulated pollutant, it is considered to be a major source for all regulated pollutants. Therefore, it is not necessary to evaluate whether the turbine upgrade modification is a significant emission increase. Significant means a net increase that would equal or exceed: NOx, 40 tpy; SO_2, 40 tpy; PM_{10}, 15 tpy; or PM_{10}, 15 tpy.

(C) The turbine upgrade modification will not result in any net emission increase at a major stationary source located within 10 km of a Class I area. One, the pre-modification MGS is not a major stationary source. Two, the nearest Class I area, San Gabriel Wilderness, is located 34 km away (p. 47 of FDOC).

Table 39 - Prevention of Significant Deterioration Applicability

	NOx	**SO_2**	**PM_{10}**	**CO**
Pre-Modification MGS, Potential to Emit (PTE), TPY (*Table 15*)	40.65	1.28	29.26	45.82
Major Source?	No, PTE is less than 100 tpy for NOx, SO_2, PM_{10}, and CO. If a source is a major source for any one regulated pollutant, it is considered to be a major source for all regulated pollutants.			
Post-Modification MGS Potential to Emit, TPY (*Table 16*)	41.31	1.36	29.26	45.82
Pre-Modification MGS Actual Emissions (2016 & 2017 Avg) TPY (per Annual Emissions Reporting)	$(19.821_{2016} + 19.702_{2017})$ /2 = 19.76	$(0.757_{2016} + 0.765_{2017})$/ 2 = 0.761	$(21.911_{2016} + 22.058_{2017})$/ 2 = 21.98	$(5.78_{2016} + 6.059_{2017})$/ 2 = 5.92
Potential to Emit Increase (Post-Modification MGS PTE – Pre-Modification MGS actual)	41.31 – 19.76 = 21.55	1.36 – 0.761 = 0.60	29.26 – 21.98 = 7.28	45.82 – 5.92 = 39.90
If Pre-Modification MGS is not a major source, does Post-Modification MGS result in an increase in potential to emit of at least 100 tpy?	No, net increase is less than 100 tpy.	No, net increase is less than 100 tpy.	No, net increase is less than 100 tpy.	No, net increase is less than 100 tpy.
PSD Applicable?	No	No	No	No

Although Bicent is not subject to PSD review for NOx, SO_2, PM_{10} and CO, Rule 1701(b)(1) provides that the BACT requirement for CO applies to a net emission increase of a criteria air contaminant from a permit unit at any stationary source. Please see ***Rule 1303(a)(1)—BACT/LAER*** for the BACT analysis for CO emissions.

Rule 1714—Prevention of Significant Deterioration for Greenhouse Gases (11/5/10)

SCAQMD adopted Rule 1714 on 11/5/10 to implement the PSD GHG requirements set forth by 40 CFR 52.21. The rule was adopted into the SIP on 12/10/12, and the delegation from EPA became effective on 1/9/13. Upon the effective date, the SCAQMD became the Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permitting authority for sources located within the SCAQMD.

The relevant rule provisions are as follows:

(a) This rule sets forth preconstruction review requirements for greenhouse gases (GHG). The provisions of this rule apply only to GHGs as defined by EPA to mean the air pollutant as an aggregate group of six GHGs: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF6). All other attainment air contaminants, as defined in Rule 1702 subdivision (a), shall be regulated for the purpose of Prevention of Significant Deterioration (PSD) requirements pursuant to Regulation XVII, excluding Rule 1714.

(c) The provisions of 40 CFR Part 52.21 are incorporated by reference, with the excluded subsections of 40 CFR Part 52.21 listed in (c)(1).

(d)(1) An owner or operator must obtain a PSD permit pursuant to this rule before beginning actual construction, as defined in 40 CFR 52.21(b)(11), of a new major stationary source or major modification to an existing major source as defined in 40 CFR 52.21(b)(1) and (b)(2), respectively.

In May 2010, EPA issued the GHG permitting rule officially known as the "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule," in which EPA defined six GHG pollutants (collectively combined and measured as carbon dioxide equivalent) as NSR-regulated pollutants and therefore subject to PSD permitting, including the preparation of a BACT analysis for GHG emissions.

The EPA's "*PSD and Title V Permitting Guidance for Greenhouse Gases*," dated March 2011, addresses the requirements in 40 CFR 52.21. The guidance document provides applicability criteria for GHG PSD and a comprehensive discussion of the five-step "Top-Down" BACT analysis to determine BACT for GHG.

Tailoring Rule Step 1— *PSD Applicability Test for GHGs in PSD Permits Issued from January 2, 2011 to June 30, 2011* provide the following applicability criteria.

PSD applies to the GHG emissions from a proposed new source if ***both*** of the following are true:

- Not considering its emissions of GHGs, the new source is considered a major source for PSD applicability and is required to obtain a PSD permit (called an "anyway source"), ***and***

- The potential emissions of GHGs from the new source would be equal to or greater than 75,000 TPY on a CO2e basis.

Tailoring Rule Step 2--*PSD Applicability Test for GHGs in PSD Permits Issued on or after July 1, 2011* provide the following applicability criteria.

PSD applies to the GHG emissions from a proposed new source if ***either*** of the following is true:

- PSD for GHGs would be required under Tailoring Rule Step 1, ***or***

- The potential emissions of GHGs from the new source would be equal to or greater than 100,000 TPY CO_2e basis ***and*** equal to or greater than the applicable major source threshold (*i.e.,* 100 or 250 TPY, depending on the source category) on a mass basis for GHGs.

GHG Tailoring Rule Step 3, issued on June 29, 2012, continued to focus GHG permitting on the largest emitters by retaining the permitting thresholds that were established in Steps 1 and 2.

On June 23, 2014, the U.S. Supreme Court issued its decision in *Utility Air Regulatory Group v. Environmental Protection Agency*, 134 S. Ct. 2427 (2014). 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 response to the Supreme Court decision, the EPA has undertaken various actions to explain the next steps in GHG permitting and conduct rulemaking action to make the appropriate revisions to the PSD and operating permit rules. In a memo, dated 7/24/14, regarding "Next Steps and Preliminary Views on the Application of Clean Air Act Permitting Programs to Greenhouse Gases Following the Supreme Court's Decision in *Utility Air Regulatory Group v. Environmental Protection Agency*," the EPA explained it will no longer require PSD or Title V permits for Step 2 sources. (A Title V permit continues to be required for the MGS facility because it is a major source for the purpose of Title V applicability.)

The EPA issued a proposed rule to revise provisions in the PSD and Title V permitting regulations applicable to greenhouse gases (40 CFR Parts 51, 52, 60, 70, and 71) to fully conform with recent court decisions, as well as implementing other provisions, in "Revisions to the Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Permitting Regulations and Establishment of a Significant Emissions Rate (SER) for GHG Emissions Under the PSD Program," 81 Federal Register 68110 (October 3, 2016). This proposed rule has not been finalized.

- ***PSD Applicability Analysis For GHGs:***
  Tailoring Rule Step 2 has been invalidated by the courts. Pursuant to Tailoring Rule Step 1, PSD applies to GHG if the source is otherwise subject to PSD for another regulated NSR pollutant and the source is with a GHG PTE $\geq$ 75,000 tons per year CO_2e. The Rule 1701 analysis above determined that the MGS facility is not otherwise subject to PSD for NOx, SO_2, PM_{10}, or CO. Therefore, the MGS facility is not subject to PSD requirements for GHG, regardless of the GHG potential emissions. As MGS is not a GHG PSD facility, it is not subject to GHG PSD BACT, which would require a Top-Down BACT analysis.

Regulation XX—RECLAIM

- **Rule 2005—New Source Review for RECLAIM**
  - ***Rule 2005(c)(1)(A)—BACT/LAER (NOx) (requires BACT for NOx for RECLAIM)***
  - ***Rule 1303(a)(1)—BACT/LAER (PM_{10}, SOx, VOC))***
  - ***Rule 1701(b)—BACT/LAER (CO) (requires BACT for CO for all facilities)***

    See Rule 1303(a)(1) analysis above.

  - ***Rule 2005(c)(1)(B)—Modeling (RECLAIM NOx)***
  - ***Rule 1303(b)(1)(B)—Modeling (CO, PM_{10}, SOx)***

    For an existing RECLAIM facility, the Executive Offer shall not approve an application for a Facility Permit Amendment to authorize the modification of an existing source which results in an emission increase, unless the applicant demonstrates that the operation of the source will not result in a significant increase in the air quality concentration for NO_2 as specified in Appendix A of the rule. Rule 2000(c)(71) defines "source" as "any individual unit, piece of equipment or process which may emit an air contaminant and which is identified, or required to be identified, in the RECLAIM Facility Permit." Therefore, modeling is required on a per permit unit basis. For attainment pollutants, such as NO_2, the project impact plus the background concentration should not exceed the most stringent air quality standard. The ambient air quality standards for NO_2 are for 1-hour averaging time and annual averaging time.

1. **A/N 598922—Modification to Turbine No. 1**
2. **A/N 598923—Modification to Turbine No. 2**

   For A/N 394164 & 394165--FDOC and A/N 517249 & 517250—Startup & Shutdown Revisions, the modeling analysis for NOx was shown under *Rule 2005(c)(1)(B)*. Therefore, the modeling analysis for these permits will be summarized below.

   For A/N 598922 & 598923-Turbine Upgrade, the consultant provided facility-wide modeling for the *Rule 1303(b)(1)—Modeling* analysis shown above but did not provide separate NOx modeling for a permit unit for *Rule 2005*. However, the SCAQMD conducted its own modeling, and the results indicate each turbine will be in compliance with the NO_2 air quality standards.

A. Initial: A/N 394164 & 394165—FDOC

The FDOC set forth the Rule 2005(b)(1)(B) modeling for NO_2 for the then new facility on pp. 51 – 55. The applicant provided a modeling analysis for maximum project impacts for NO_2 using ISCST3 dispersion model (version 00101) and representative meteorological data from the Vernon meteorological station.

The maximum ground level impacts were evaluated for four scenarios--commissioning, startup, normal operation, and normal shutdown, each with different operating conditions and emission rates--to determine the worst case for impacts.

Four Scenarios—Maximum Emissions

A description of the four scenarios and a tabulation of the maximum emissions for each scenario are presented below. The emissions were used as input data for the modeling analysis.

1. Commissioning Scenario
   During commissioning, NOx emissions are higher than during normal operation because the combustors are not optimally tuned and/or the SCR/CO control may not be fully functional. The commissioning of each CTG will take place over 74 days. The commissioning for the two CTGs will take place over three months, with the commissioning of the second unit beginning 15 days after the start of the commissioning of the first unit and lasting through the 89th day of the commissioning period. Manufacturer data was used to estimate the NOx emissions.

2. Startup Scenarios
   For the FDOC, the NOx model results for startup were based on the maximum hourly emissions for cold startup, because cold start emissions are higher than warm start and hot start emissions rates. During startup, NOx emissions are higher than during normal operation because the SCR has not reached optimal temperature to control to BACT level. NOx emissions are the highest during the first hour of cold startup at 38 °F, pursuant to manufacturer's data and fuel usage. For the worst case, the applicant proposed that both turbines will start up simultaneously.

3. Normal Operation Scenario
   As discussed above under Emissions Calculations, the highest NOx hourly emissions occur under Scenario S13 (100% load, 38 °F ambient).

4. Shutdown Scenario
   During the 30-minute shutdown, the NOx emissions are higher as the SCR/CO oxidation catalyst is being shut down. The shutdown emissions occur for the worst case under Scenario S13.

   A tabulation of the maximum hourly and annual NOx emissions for the four operating scenarios is presented in the table below. (As shown below, the actual annual average modeling results were based on the more conservative case of normal operations of 8760 hours with 56 cold starts and shutdowns, rather than the annual NOx emissions shown in the table below.)

Table 40 - Maximum Hourly and Annual NOx Emission for the Four Operating Scenarios (A/N 394164 & 394165-FDOC)

Operating Scenario	NOx Emissions, 1-hr maximum, lb/hr	Annual NOx emissions, lb/yr
Commissioning CT01 [Day 16]	11.75[1] (1.48 g/s)	N/A
Commissioning CT02 [Day 1]	36.35[2] (4.58 g/s)	N/A
Startup, Cold CT01	13.10[3] (1.65 g/s)	63[7]
Startup, Cold CT02	13.10 (1.65 g/s)	63
Startup, Warm CT01	12.22[4] (1.54 g/s)	698[8]
Startup, Warm CT02	12.22 (1.54 g/s)	698
Normal CT01	4.07[5] (0.513 g/s)	26,200[9]
Normal CT02	4.07 (0.513 g/s)	26,200
Shutdown CT01	5.51[6] (0.694 g/s)	N/A
Shutdown CT02	5.51 (0.694 g/s)	N/A

[1] CT01 NOx emissions on 16th day of commissioning, 1st hr cold start (Appendix B1, Appl for P/C-P/O)
[2] CT02 NOx emissions on 1st day of commissioning, 1st hr warm start (W2, from Appendix B3, Appl for P/C-P/O)
[3] NOx emissions of 1st hr cold start (C1, from Appendix B2, Appl for P/C-P/O)
[4] NOx emissions of 1st hr warm start (W1, from Appendix B3, Appl for P/C-P/O)
[5] NOx emissions (Scenario S13, normal operation, Appendix B5, Appl for P/C-P/O)
[6] NOx emissions during 30 minutes of shutdown (SH1, Appendix B6, Appl for P/C-P/O)
[7] NOx emissions for 4 cold startups per year (Table 2, Attachment 3, Appl for P/C-P/O)
[8] NOx emissions for 52 warm starts per year (Table 2, Attachment 3, Appl for P/C-P/O)
[9] NOx emissions based on 1314 hours of operation with duct burner on, 5782 hours with duct burner off, 4 cold starts and 52 warm starts per year (Table 2, Attachment 3, Appl for P/C-P/O)

Maximum Ground Level Impacts

The applicant performed a modeling analysis for each of the above scenarios to determine the maximum ground level NOx concentrations.

- *1-Hr Average*

  For the 1-hr average, the impact results for two turbines are presented in the following table.

Table 41 - NOx Modeling Results (1-hr Average) for Two CTs (A/N 394164 & 394165-FDOC)

Scenario	Modeled Concentration µg/m³	Background Concentration µg/m³	Modeled + Background Concentrations µg/m³	State Standard µg/m³	Federal Standard µg/m³
Commissioning	39.4	338.4	377.8	470	---
Cold Startup	21.8	338.4	360.2	470	---
Normal Operation	5.9	338.4	344.3	470	---
Shutdown	9.2	338.4	347.6	470	---

Ref: Tables 7 and 8, Attachment 3, Appl. for P/C-P/O

- *Annual Average*
  For the annual average, the modeling was based on both turbines under normal operation for 8760 hours, including 56 starts (all cold starts to be conservative) and 56 shutdowns per year per turbine. The impact results are presented in the following table.

Table 42 - NOx Modeling Results (Annual Average) for Two Turbines (A/N 394164 & 394165-FDOC)

Scenario	Modeled Concentration µg/m^3	Background Concentration µg/m^3	Modeled + Background Concentrations µg/m^3	State Standard µg/m^3	Federal Standard µg/m^3
Normal Operation/ Startup/Shutdown	0.4	80.5	80.9	100	100

Ref: Table 9, Attachment 3, Appl. for P/C-P/O

Conclusion
As shown the table above, the estimated NO_2 air quality impacts for two turbines added to the background NO_2 concentration were less than the most stringent NO_2 air quality standards for the 1-hr average and the annual average. Therefore, the NO_2 air quality impacts were determined to comply with Rule 2005.

♦♦♦

B. Pre-Modification: A/N 517249 & 517250--Startup & Shutdown Revisions

The increase in maximum hourly NOx emissions for cold and non-cold startups, as well as the increase to two startups per day, were evaluated to determine the effects on modeling results. The Application did not include a modeling analysis.

Four Scenarios—Maximum Emissions

1. Commissioning Scenario
   Same as FDOC.

2. Startup Scenarios
   For the FDOC, the NOx model results for startup were based on the maximum hourly emissions for cold startup, because cold start emissions are higher than warm start and hot start emissions rates. For the worst case, the applicant had proposed that both turbines will start up simultaneously.

   For A/N 517249 & 517250, the increase in NOx emissions for cold startups was required to be evaluated.

3. Normal Operation Scenario
   Same as FDOC.

4. Shutdown Scenario
   The increase in shutdown emissions was not required to be evaluated because shutdown emissions are lower than startup emissions.

Maximum Ground Level Impacts
The effects of the increased maximum hourly NOx emissions for cold startups are evaluated below.

- *1-Hr Average*
  The following table shows the increase in maximum hourly emissions for cold startup for two turbines.

Table 43 - Maximum Hourly Emissions
(A/N 517249 & 517250-Startup & Shutdown Revisions)

Pollutants	Maximum Hourly Emissions [1]	
	FDOC	CEC Order No. 08-813-4 [2]
NOx	13.1 lb/hr-turbine x 2 turbines = 26.2 lb/hr for two turbines	55 lb/hr for two turbines (equal to 27.2 lb/hr for one turbine)

[1] The maximum hourly NOx emissions occur under the first hour of cold startup when the SCR is not warmed up.
[2] The District has not previously evaluated the effect of the CEC's approved emissions limit increases.

For the FDOC, the cold startup impact for two CTs was 21.8 µg/m^3 based on 26.2 lb/hr. Based on the CEC Order, the maximum hourly emissions for two turbines increased from 26.2 lb/hr to 55 lb/hr.

The effect of the increase in maximum hourly emissions on ground level impact was estimated by multiplying the FDOC ground level impact by the ratio of the A/N 517249 & 517250 increased maximum hourly emissions to the FDOC maximum hourly emissions, as shown below.

Two Turbines
(21.8 µg/m^3) (55 lb/hr / 26.2 lb/hr) = 45.76 µg/m^3

As discussed for Rule 1303(b)(1) above, this methodology using ratios was proposed by the consultant who prepared the original modeling and was accepted by CEC staff for the CEC Order.

The above estimated increase in modeling results is reflected in the table below. On 4/12/10, the U.S. EPA established the new federal 1-hour NO_2 standard of 100 ppb

(188 µg/m^3). The form of the federal 1-hour NO_2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations.

Then Program Supervisor Tom Chico provided the background concentrations for the state standard (representative 1-hr) and the federal standard (98th percentile 1-hr). The changes to the A/N 394164 & 394165--FDOC modeling results are shown in the table below.

Table 44 - NOx Modeling Results (1-hr Average) for Two Turbines (A/N 517249 & 517250-Startup & Shutdown Revisions)

Scenario		Modeled Concentration µg/m^3	Background Concentration µg/m^3	Modeled + Background Concentrations µg/m^3	State Standard µg/m^3	**Federal Standard µg/m^3**
Commissioning		Same as FDOC.				
Cold Startup	1-hour	~~21.8~~ 45.76	~~338.4~~ 226	~~360.2~~ 271.76	~~470~~ 339	
	1-hour (98% percentile)	45.76	133	178.76		188
Normal Operation		Same as FDOC.				
Shutdown		Not evaluated because shutdown emissions are lower than startup emissions.				

As shown the table above, the estimated NO_2 air quality impact for two turbines added to the background NO_2 concentration is less than the most stringent NO_2 air quality standards for the 1-hr average. Therefore, the NO_2 air quality impact was determined to continue to comply with Rule 1303 when two turbines are started up simultaneously.

- *Annual Average*

  FDOC Annual Emissions

  The FDOC indicated the modeling was based on both turbines under normal operation for 8760 hours, including 56 starts (all cold starts to be conservative) and 56 shutdowns per year per turbine, but did not provide the actual annual NOx emissions. The annual emissions will be calculated here as follows:

  One year is 8760 hours. The remaining hours of operation (8620 hrs) will be in normal mode per Scenario S13.

  Normal hrs of operation = 8760 hrs – [56 startups (2 hrs) + 56 shutdowns (0.5 hr each)] = 8620 hrs

Annual emissions = [(15.75 lb/cold start)(56 cold starts) + (5.51 lb/shutdown) (56 shutdowns) + (4.08 lb/hr normal operation)(8620 hr)][2 turbines] = 72,720.32 lb

A/N 517249 & 517250-Increased Annual Emissions
The annual emissions with the startup and shutdown changes are calculated as follows:

Annual emissions = [(122.8 lb/cold start)(56 cold starts) + (4.50 lb/shutdown) (56 shutdowns) + (4.08 lb/hr normal operation)(8620 hr)] [2 turbines] = 84,596.80 lb

For the FDOC, the impact for two CTs was 0.4 µg/m^3 based on 72,720.32 lb/yr. Based on the CEC Order, the annual emissions for two turbines increased from 72,720.32 lb/yr to 84,596.80 lb/yr.

The effect of the increase in maximum annual emissions on ground level impact was conservatively estimated by multiplying the FDOC impact by the ratio of the A/N 517249 & 517250 maximum annual emissions to the FDOC maximum annual emissions, as shown below.

Two Turbines
(0.4 µg/m^3) (84,596.80 lb/hr / 72,720.32 lb/hr) = 0.47 µg/m^3

This methodology using ratios is the same methodology as was used by CEC staff for the CEC Order. The above estimated increase in modeling results is reflected in the table below. Then-Program Supervisor Tom Chico provided the background concentrations for the annual standard. The changes to the FDOC modeling results are shown in the table below.

Table 45 - NOx Modeling Results (Annual Average) for Two Turbines (A/N 517249 & 517250-Startup & Shutdown Revisions)

Scenario	Modeled Concentration µg/m^3	Background Concentration µg/m^3	Modeled + Background Concentrations µg/m^3	State Standard µg/m^3	Federal Standard µg/m^3
Normal Operation/ Startup/Shutdown	~~0.4~~ 0.47	~~80.5~~ 52.8	~~80.9~~ 53.27	~~100~~ 57	~~100~~ 100

The estimated NO_2 air quality impacts added to the background NO_2 concentration were less than the most stringent NO_2 air quality standards for the annual average

standard. Therefore, the NO_2 air quality impact was determined to continue to comply with Rule 1303.

Conclusion

As shown the tables above, the estimated NO_2 air quality impacts for two turbines added to the background NO_2 concentration is less than the most stringent NO_2 air quality standards for the 1-hr average and the annual average. Therefore, the NO_2 air quality impacts would continue to comply with Rule 2005.

C. Post-Modification: A/N 598922 & A/N 598923—Turbine Upgrade

See Rule 1303(b)(1) analysis above.

The NOx modeling is included in the Rule 1303(b)(1) modeling analysis above. The consultant provided facility-wide modeling that included NO_2, CO, PM_{10}, and SO_2 for Rule 1303, but did not provide separate modeling for NO_2 on a permit unit basis for Rule 2005. However, the SCAQMD conducted its own modeling, and the results indicate each turbine will be in compliance with the NO_2 air quality standards.

♦♦

- ***2005(c)(2)—Offsets***
  1. **A/N 598922—Modification to Turbine No. 1**
  2. **A/N 598923—Modification to Turbine No. 2**

A. Initial: A/N 394164 & 394165--FDOC

Rule 2005(c)(2), as amended 5/6/05, required RECLAIM facilities to hold sufficient RTCs to offset the first year of operation's emissions increase from a new or modified source before commencement of such operation. Before Rule 2005 was amended on 6/3/11, Rule 2005(f)(1) also required RECLAIM facilities to hold RTCs for each subsequent compliance year prior to each compliance year for the same sources. Further, facilities subject to this NSR hold requirement were generally required to hold and not transfer out of their Allocation accounts the specified RTCs for each year until the compliance year was over.

Accordingly, the Vernon City, Light & Power Dept. facility permit included the following condition:

I296.1 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year 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 first

compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

On 6/3/11, Rule 2005 was amended to remove existing facilities that do not have emissions greater than the level of their 1994 allocation plus non-tradable credits (NTCs) from section (f)(1). Per Rule 2000(c)(35), an existing facility is "any facility that submitted Emission Fee Reports pursuant to Rule 301 – Permit Fees, for 1992 or earlier years, or with valid District Permits to Operate issued prior to October 15, 1993, and continued to be in operation or possess valid District permits on October 15, 1993." Per Rule 2000(c)(51), a new facility is "any facility which has received all District Permits to Construct on or after October 15, 1993."

Existing facilities that do not have emissions greater than the level of their 1994 allocation plus NTCs are only subject to the "hold" requirement for the first year of operation of each source with an emissions increase (the period commencing at the start of operation and concluding 364 days later; 365 days later if the period includes a leap day).

After the above 2005 amendments became SIP-approved, the SCAQMD re-issued in July 2012 the Cycle II RECLAIM facility permits that included a condition I296 to implement the amendments. Not all RECLAIM facility permits included a condition I296.

- For existing facilities that were subject to the "hold" condition for the first year only, the I296.1 condition was replaced with an I297 condition for those devices with an emissions increase that were still in the first year of operation. The I296.1 conditions were removed from the facility permit for all other devices.

- For existing facilities that were subject to the "hold" condition the first year and each subsequent year, and for new facilities, the I296 conditions were replaced with I298 conditions.

On July 26, 2012, the SCAQMD re-issued the facility permit to Bicent. Since Bicent was a partial change of operator, the RECLAIM Administration Team determined that Bicent was a "new" facility for the purposes of Rule 2005(f)(1). The I296.1 condition became two I298 conditions.

I298.1 This equipment shall not be operated unless the facility holds 35263 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 35263 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 condition(s) stated in this permit.

[RULE 2005, 6-3-2011]

[Devices subject to this condition: D27, D31]

I298.2 This equipment shall not be operated unless the facility holds 35263 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 35263 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 condition(s) stated in this permit.

[RULE 2005, 6-3-2011]

[Devices subject to this condition: D36, D39]

The amount of NOx RTCs required to be held for each turbine was 35,263 lbs/year. The RTCs were based on 4 cold startups, 52 warm startups, 56 shutdowns, and 8646 hr normal operation (as calculated below), emissions per event and emissions rates from the manufacturer.

Hours of normal operation = 8760 hrs – [(4 cold starts)(2 hr/cold start) + (52 warm starts)(1.5 hr/warm start) + (56 shutdowns)(0.5 hr/shutdown)] = 8646 hr

(4 cold starts)(15.75 lb/cold start) + (52 warm starts)(13.48 lb/warm start) + (56 shutdowns)(5.51 lb/shutdown) + (8646 hr normal operation)(4.08 lb/hr controlled) = 35,263 lbs/year

♦♦

B. <u>Pre-Modification: A/N 517249 & 517250—Startup and Shutdown Revisions</u>

Pursuant to the revisions to conditions A99.3 and A99.4 for startups and shutdowns, the amount of NOx RTCs required was revised to be based on 30 cold startups, 26 warm startups, 56 shutdowns, and 8633 hr normal operation (as calculated below) and revised emissions per startup and shutdown event.

Hours of normal operation = 8760 hrs – [(30 cold starts)(2 hr/cold start) + (26 warm starts)(1.5 hr/warm start) + (56 shutdowns)(0.5 hr/shutdown)] = 8633 hr

(30 cold starts)(122.8 lb/cold start) + (26 warm starts)(51.3 lb/warm start) + (56 shutdowns)(4.5 lb/shutdown) + (8633 hr normal operation)(4.08 lb/hr controlled, *Scenario S13*) = 40,492 lbs/year

Condition nos. I298.1 and I298.2 were revised to change the 35263 lb/yr to 40,492 lbs/year. Based on the facility's holdings for the compliance year and future years, the facility was required to purchase 1073 lbs RTCs before the permits were issued on 10/9/13.

On 8/31/14, the facility permit was re-issued to reflect the RECLAIM Administration policy to require separate I298 conditions for the turbine and the duct burner with the RTCs apportioned based on relative ratings. The separate I298 conditions are required for administrative purposes and not intended to accurately reflect anticipated NOx emissions from the turbine versus the duct burner. The NOx emissions from the turbine and duct burner will continue to be measured by a single CEMS in the exhaust stack. Consequently, condition I298.1 for Turbine No. 1 and Duct Burner (40,492 lbs) became I298.1 for Turbine No. 1 (34,349 lbs) and I298.2 for Duct Burner (6143 lbs). Condition I298.2 for Turbine No. 2 and Duct Burner (40,492 lbs) became I298.3 for Turbine No. 1 (34,349 lbs) and I298.4 for Duct Burner (6143 lbs).

♦♦

C. <u>Post-Modification: A/N 598922 & A/N 598923—RTCs for Turbine Upgrade</u>

For <u>A/N 517249 & 517250—Startup and Shutdown Revisions</u>, pursuant to permitting practice at that time, the maximum operating rate was used to determine the RTCs required. Specifically, the NOx RTCs required were based on the maximum NOx normal operating rate of 4.08 lb/hr based on Scenario S13 (100% load at 38 ºF) to arrive at the 40,492 lb/yr combined for a turbine and duct burner.

For <u>A/N 598922 & 598923--Turbine Upgrade</u>, 40,492 lbs NOx RTCs will continue to be required per turbine. For Case S13, the maximum NOx rate will increase from 4.08 lb/hr to 4.158 lb/hr. However, pursuant to permitting practice at this time, the average operating rate will be used to determine the RTCs required. For Case S15, the average

NOx rate will increase from 3.96 lb/hr to 4.078 lb/hr. The post-modification average rate of 4.078 lb/hr rounds up to be equal to the pre-modification basis of 4.08 lb/hr. Therefore, conditions I298.1, I298.2, I298.3, and I298.4 will not be revised.

Hours of normal operation = 8760 hrs – [(30 cold starts)(2 hr/cold start) + (26 warm starts)(1.5 hr/warm start) + (56 shutdowns)(0.5 hr/shutdown)] = 8633 hr

(30 cold starts)(122.8 lb/cold start) + (26 warm starts)(51.3 lb/warm start) + (56 shutdowns)(4.5 lb/shutdown) + (8633 hr normal operation)(4.08 lb/hr controlled, *Case S15*) = 40,492 lbs/year

The purpose of the I298 conditions is to implement the RECLAIM New Source Review offset requirements of Rule 2005(f). In December 2015, Rule 2002(f) was amended to make reductions/adjustments to NOx RTC Allocation and Holdings (NOx RECLAIM shave). In response to several electrical generating facility operators' concerns with concurrent compliance with the RTC allocation shave and the NSR holding requirements per Rule 2005, Rule 2002(f)(1)(G) allows the use of three categories of RTCs to meet the NSR holding requirements. Therefore, the NOx RECLAIM shave did not require additional RTCs to be purchased to meet the I298 conditions.

♦♦

- ***Rule 2005(e)-Trading Zone Restrictions***
- ***Rule 1303(b)(3)—Sensitive Zone Requirements***
  See Rule 1303(b)(3) analysis above.

- ***Rule 2005(g)—Additional Federal Requirements for Major Stationary Sources***
  - ***Rule 2005(g)(1) – Statewide Compliance***
  - ***Rule 1303(b)(5)(B) – Statewide Compliance***
    See Rule 1303(b)(5)(B) analysis above.

  - ***Rule 2005(g)(2)—Alternative Analysis***
  - ***Rule 2005(g)(3)—Compliance through CEQA,***
  - ***Rule 1303(b)(5)(A) – Alternative Analysis***
  - ***Rule 1303(b)(5)(D) – Compliance through CEQA***
    See Rule 1303(b)(5)(A) & (D) analysis above.

  - ***Rule 2005(g)(4)—Protection of Visibility***
  - ***Rule 1303(b)(5)(C) –Protection of Visibility***
    See Rule 1303(b)(5)(C) analysis above.

- ***Rule 2005(h)—Public Notice (RECLAIM)***
- ***Rule 212—Standards for Approving Permits***
  See Rule 212 analysis above.

- ***Rule 2005(i)–Rule 1401 (RECLAIM)***
- ***Rule 1401—New Source Review of Toxic Air Contaminants, as amended 9/1/17***
  See Rule 1401 analysis above.

Regulation XXX—Title V Permits

- **Rule 3000—General**
  The proposed facility permit revision is considered as a "significant permit revision."

  Rule 3000(b)(31) defines "significant permit revision" to mean "any facility permit revision that is not eligible for administrative permit revision, minor permit revision, or de minimis significant permit prevision procedures. Such revisions include any of the following:

  (J) modification or reconstruction of existing equipment, resulting in an emission increase subject to new or additional NSPS requirements pursuant to 40 CFR Part 60, or to new or additional NESHAP requirements pursuant to 40 CFR Part 61 or 40 CFR Part 63.

  Prior to the turbine upgrade project, the turbines were subject to Subpart GG. Subsequent to the turbine upgrade, the turbines will be subject to Subpart KKKK, because of the increase in NOx hourly emission rate. (See regulatory analysis for Subparts GG and KKKK below.) Therefore, this proposed facility permit revision is a "significant permit revision."

- ***Rule 3003—Applications***
  (j) EPA Review
  (1) The Executive Officer shall submit to the EPA Administrator:
  (A) each application for initial permit, permit renewal, minor permit revision, de minimis significant permit revision and significant permit revision;
  (B) each proposed permit for initial permit, renewal permit, or permit revision, excluding administrative permit revisions;
  (C) any revisions to the proposed permit in response to public or affected State comments;
  (D) a copy of any notices required by Rules 3003, 3005, or 3006; and,
  (E) each final Title V permit, within 5 working days of permit issuance.

(k) EPA Objection

(1) No permit or permit revision for which an application must be transmitted to EPA pursuant to subdivision (j) of this rule may be issued if the EPA objects to its issuance in writing within 45 days of receipt of the proposed permit and all necessary supporting information, or within 90 days if the EPA provides a written request to delay the permit issuance on the basis that an additional 45 days is necessary to review the public and affected State comments made to the proposed permit. The objection shall include a statement of the reasons for the objection and a description of the terms and conditions that the permit must include to respond to the objections.

(m) Review by Affected States

(1) Except for administrative permit revisions, the Executive Officer shall give notice of each proposed permit to any affected State on or before the notice is provided to the EPA.

(2) Any affected State may provide recommendations in writing, based upon applicable requirements or requirements of 40 CFR Part 70, with respect to the proposed permit, within 30 days of receipt of the notice.

- ***Rule 3006—Public Participation***

(a) Public Participation Requirements for Permit Actions

(1) All permit actions for initial permit issuance, significant permit revisions, establishment of general permits and permit renewals shall include the following public participation procedures:

(A) The District shall give notice by publication in a newspaper of general circulation in the county where the source is located, by mail to those who request in writing to be on a list to receive all such notices, and by any other means determined by the Executive Officer to be necessary to assure adequate notice to the affected public.

(B) The notice shall include:

(i) The identity and location of the affected facility;

(ii) The name and mailing address of the facility's contact person;

(iii) The identity and address of the SCAQMD as the permitting authority processing the permit;

(iv) The activity or activities involved in the permit action;

(v) The emissions change involved in any permit revision;

(vi) The name, address, and telephone number of a person whom interested persons may contact to review additional information including copies of the proposed permit, the application, all relevant supporting materials, including compliance documents as defined in paragraph (b)(5) of Rule 3000, and all other materials available to the Executive Officer that are relevant to the permit decision;

(vii) A brief description of the public comment procedures provided; and
(viii) The time and place of any proposed permit hearing that may be held or a statement of the procedures to request a proposed permit hearing if one has not already been requested.

(D) The notice shall provide at least 30 days for public comment, and shall give at least 30 days of notice if any proposed permit hearing is scheduled.

(F) Any person may request a proposed permit hearing on an application for initial permit, permit renewal, or significant permit revision, or for establishment of a general permit, by filing with the Executive Officer a complete request for a proposed permit hearing within 15 days of the date of publication of notice. On or before the date the request is filed, the person requesting a proposed permit hearing must also mail by first class mail a copy of the request to the contact person of the Title V facility at the address listed in the notice. A complete request for a proposed permit hearing shall include all of the following information: ….

Analysis: Pursuant to Rule 3003(j), the proposed permit package for the significant revision will be submitted to EPA for a 45-day review period. If comments are received for the public notice, the EPA 45-day review period will begin after the SCAQMD's responses to comments have been submitted to EPA along with any changes to the documents previously submitted. Pursuant to Rule 3003(m), the public notice will be sent to the affected states for a 30-day review period.

Pursuant to Rule 3006(a)(1)(A), the SCAQMD will publish the public notice in a newspaper of general circulation in the county where the source is located, i.e., Daily News Los Angeles. In addition, the SCAQMD will mail the notice to the California Air Resource Board, local air pollution control districts, environmental groups, and interested parties. The public notice, Statement of Basis and proposed Title V facility permit will be available for review on the SCAQMD website, at the SCAQMD's headquarters in Diamond Bar, and at the Vernon-Leon H. Washington Jr. Memorial Branch Library, 4504 S. Central Avenue, Los Angeles, CA 90011.

Pursuant to Rule 3006(a)(1)(F), any person may request a proposed permit hearing on this application for a significant Title V permit revision by filing with the Executive Officer a complete Hearing Request Form (Form 500G) for a proposed hearing within 15 days of the publication of the notice. The deadline for a hearing request is included in the published public notice. Pursuant to Rule 3006(a)(1)(D), any person wishing to comment on the air quality elements of the permits must submit comments in writing to the SCAQMD within at least 30 days of the publication of the notice. The deadline for comments is included in

the published public notice. If the hearing request or public comment end date falls on a Saturday, Sunday, or Monday, the end date is typically extended (by SCAQMD internal policy) so that the deadline falls on an SCAQMD business day to allow commenters access to SCAQMD staff on the end date.

Federal Regulations

40 CFR 60 Subpart A—General Provisions

The turbines will be subject to *40 CFR 60 Subpart KKKK—NSPS for Stationary Gas Turbines* (see regulatory analysis below). The applicable provisions of Subpart KKKK refer to the sections below from *40 CFR 60 Subpart A*.

§60.7 Notification and record keeping.

(c) Each owner or operator required to install a continuous monitoring device shall submit excess emissions and monitoring systems performance report (excess emissions are defined in applicable subparts) and-or summary report form (see paragraph (d) of this section) to the Administrator semiannually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. All reports shall be postmarked by the 30th day following the end of each six-month period. Written reports of excess emissions shall include the following information: ….

(1) The magnitude of excess emissions computed in accordance with §60.13(h), any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions. The process operating time during the reporting period.

(2) Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of the affected facility. The nature and cause of any malfunction (if known), the corrective action taken or preventative measures adopted.

(3) The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustments.

(4) When no excess emissions have occurred or the continuous monitoring system(s) have not been inoperative, repaired, or adjusted, such information shall be stated in the report.

Analysis: Condition H23.2 will be added to require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK (see regulatory analysis below).

§60.8 Performance Tests

(a) Except as specified in paragraphs (a)(1),(a)(2), (a)(3), and (a)(4) of this section [all regarding a force majeure event], within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of such facility, or at such other times specified by this part, and at such other times as may be required by the Administrator under section 114 of the Act, the owner or operator of such facility shall conduct performance test(s) and furnish the Administrator a written report of the results of such performance test(s).

Analysis: Condition H23.2 will be added to require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK (see regulatory analysis below).

§60.13 Monitoring requirements

(a) For the purposes of this section, all continuous monitoring systems required under applicable subparts shall be subject to the provisions of this section upon promulgation of performance specifications for continuous monitoring systems under appendix B to this part [Performance Specifications] and, if the continuous monitoring system is used to demonstrate compliance with emission limits on a continuous basis, appendix F to this part [Quality Assurance Procedures], unless otherwise specified in an applicable subpart or by the Administrator. Appendix F is applicable December 4, 1987.

(b) All continuous monitoring systems and monitoring devices shall be installed and operational prior to conducting performance tests under §60.8. Verification of operational status shall, as a minimum, include completion of the manufacturer's written requirements or recommendations for installation, operation, and calibration of the device.

(c) If the owner or operator of an affected facility elects to submit continuous opacity monitoring system (COMS) data…. Otherwise, the owner or operator of an affected facility shall conduct a performance evaluation of the COMS or continuous emission monitoring system (CEMS) during any performance test required under §60.8 or within 30 days thereafter in accordance with the applicable performance specification in appendix B of this part [Performance Specifications]. The owner or operator of an affected facility shall conduct COMS or CEMS performance evaluations at such other times as may be required by the Administrator under section 114 of the Act.

(1) ….

(2) Except as provided in paragraph (c)(1) of this section, the owner or operator of an affected facility shall furnish the Administrator within 60 days of completion two or, upon request, more copies of a written report of the results of the performance evaluation.

(d) (1) Owners and operators of a CEMS installed in accordance with the provisions of this part, must check the zero (or low level value between 0 and 20 percent of span value) and span (50 to 100 percent of span value) calibration drifts at least once each operating day in accordance with a written procedure. The zero and span must, at a minimum, be adjusted whenever either the 24-hour zero drift or the 24-hour span drift exceeds two times the limit of the applicable performance specification in appendix B of this part [Performance Specifications]. The system must allow the amount of the excess zero and span drift to be recorded and quantified whenever specified….

(2) ….

(e) Except for system breakdowns, repairs, calibration checks, and zero and span adjustments required under paragraph (d) of this section, all continuous monitoring systems shall be in continuous operation and shall meet minimum frequency of operation requirements as follows:

(1) ….

(2) All continuous monitoring systems referenced by paragraph (c) of this section for measuring emissions, except opacity, shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(f) All continuous monitoring systems or monitoring devices shall be installed such that representative measurements of emissions or process parameters from the affected facility are obtained. Additional procedures for location of continuous monitoring systems contained in the applicable Performance Specifications of appendix B of this part [Performance Specifications] shall be used.

(h)

(1) ….

(2) For continuous monitoring systems other than opacity, 1-hour averages shall be computed as follows, except that the provisions pertaining to the validation of partial operating hours are only applicable for affected facilities that are required by the applicable subpart to include partial hours in the emission calculations:

(i) Except as provided under paragraph (h)(2)(iii) of this section, for a full operating hour (any clock hour with 60 minutes of unit operation), at least four valid data points are required to calculate the hourly average, *i.e.*, one data point in each of the 15-minute quadrants of the hour.

(ii) Except as provided under paragraph (h)(2)(iii) of this section, for a partial operating hour (any clock hour with less than 60 minutes of unit operation), at least one valid data point in each 15-minute quadrant of the hour in which the unit operates is required to calculate the hourly average.

(iii) For any operating hour in which required maintenance or quality-assurance activities are performed:
  (A) If the unit operates in two or more quadrants of the hour, a minimum of two valid data points, separated by at least 15 minutes, is required to calculate the hourly average; or
  (B) If the unit operates in only one quadrant of the hour, at least one valid data point is required to calculate the hourly average.

(iv) If a daily calibration error check is failed during any operating hour, all data for that hour shall be invalidated, unless a subsequent calibration error test is passed in the same hour and the requirements of paragraph (h)(2)(iii) of this section are met, based solely on valid data recorded after the successful calibration.

(v) For each full or partial operating hour, all valid data points shall be used to calculate the hourly average.

(vi) Except as provided under paragraph (h)(2)(vii) of this section, data recorded during periods of continuous monitoring system breakdown, repair, calibration checks, and zero and span adjustments shall not be included in the data averages computed under this paragraph.

(vii) Owners and operators complying with the requirements of §60.7(f)(1) or (2) must include any data recorded during periods of monitor breakdown or malfunction in the data averages.

(viii) When specified in an applicable subpart, hourly averages for certain partial operating hours shall not be computed or included in the emission averages (e.g., hours with < 30 minutes of unit operation under §60.47b(d)).

(ix) Either arithmetic or integrated averaging of all data may be used to calculate the hourly averages. The data may be recorded in reduced or nonreduced form (e.g., ppm pollutant and percent O_2 or ng/J of pollutant).

(3) All excess emissions shall be converted into units of the standard using the applicable conversion procedures specified in the applicable subpart. After conversion into units of the standard, the data may be rounded to the same number of significant digits used in the applicable subpart to specify the emission limit.
  (i) After receipt and consideration of written application, the Administrator may approve alternatives to any monitoring procedures or requirements of this part including, but not limited to the following: ….

(j) An alternative to the relative accuracy (RA) test specified in Performance Specification 2 of appendix B [Performance Specifications] may be requested as follows: ….

Analysis: Condition H23.2 will be added to require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK (see regulatory analysis below).

40 CFR Part 60 Subpart GG—Standards of Performance for Stationary Gas Turbines

- **Applicability Requirements**

§60.330 Applicability and designation of affected facility

(a) The provisions of this subpart are applicable to the following affected facilities: All stationary gas turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the lower heating value of the fuel fired.

(b) Any facility under paragraph (a) of this section which commences construction, modification, or reconstruction after October 3, 1977, is subject to the requirements of this part except as provided in paragraphs (e) and (j) of §60.332.

Analysis: On p. 57, the FDOC indicated the MGS is subject to Subpart GG because the turbines are rated at greater than 10 MMBtu/hr and construction will commenced after 10/3/77. The limits are 110 ppm NOx and 150 ppm SOx on the current facility permit.

As analyzed below, the turbines will be subject to Subpart KKKK, which will supersede Subpart GG after the turbine upgrade.

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

§60.4300—What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of emissions from stationary combustion turbines that commenced construction, modification or reconstruction after February 18, 2005.

§60.4305—Does this subpart apply to my stationary combustion turbine?

(a) If you are the owner or operator of a stationary combustion turbine with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification or reconstruction after February 18, 2005, your turbine is subject to this subpart. Only heat input to the combustion turbine should be included when determining whether or not this subpart is applicable to the turbine. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining the peak heat input. However, this part does apply to emissions from any associated HRSG and duct burners.

(b) Stationary combustion turbines regulated under this subpart are exempt from the requirements of subpart GG of this part. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of subparts Da, Db, and Dc.

Analysis:
The applicable definitions are provided below followed by the analysis.

40 CFR 60 Subpart A—General Provisions provides definitions for "commenced," "construction" and "modification."

- **§60.2 Definitions**

  Commenced means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

  Construction means fabrication, erection, or installation of an affected facility.

  Modification means any physical change in, or change in the method of operation of, an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.

- **§60.14 Modification**

  (a) Except as provided under paragraphs (e) and (f) of this section, any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies shall be considered a modification within the meaning of section 111 of the Act. Upon modification, an existing facility shall become an affected facility for each pollutant to which a standard applies and for which there is an increase in the emission rate to the atmosphere.

§60.4420 What definitions apply to this subpart?

- *ISO conditions* means 288 Kelvin, 60 percent relative humidity and 101.3 kilopascals pressure.

- *Peak load* means 100 percent of the manufacturer's design capacity of the combustion turbine at ISO conditions.

The peak load is the rating at Independent System Operator (ISO) standard conditions (59 ºF, 60% relative humidity, 1 atm). These conditions correspond to Case S14 (100% load, 59 ºF ambient). The rating will increase from 443.56 MMBtu/hr (from Appendix B-5 of Application for P/C, A/N 394164) to 480.12 MMBtu/hr after the turbine upgrade (Siemens

Table 1). The resulting 480.12 MMBtu/hr rating is greater than the 10 MMBtu/hr applicability threshold set forth in §60.4305(a) above.

The construction of the turbines commenced before 2/18/05 as operation began in July 2005. Therefore, the turbines were subject to Subpart GG. However, the turbine upgrade modification will commence after 2/18/05. The turbine upgrade is a modification because it will result in a physical change in the turbines which will increase the NOx emission rate. For Case S14, the NOx rate will increase from 3.94 lb/hr (from Appendix B-5 of Application for P/C, A/N 394164) to 4.115 lb/hr (Siemens Table 1). NOx is a pollutant to which a standard applies because Subparts GG and KKKK provide standards for NOx emissions from combustion turbines. Therefore, the turbines will be subject to Subpart KKKK pursuant to §60.4305(a), and exempt from Subpart GG pursuant to §60.4305(b).

§60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_x) and sulfur dioxide (SO_2).

§60.4320 What emission limits must I meet for nitrogen oxides (NOx)?

(a) You must meet the emission limits for NOx specified in Table 1 of this subpart.

Table 1 to Subpart KKKK of Part 60—Nitrogen Oxide Emission Limits for New Stationary Combustion Turbines

Combustion turbine type	Combustion turbine heat input at peak load (HHV)	NO_x emission standard
Modified or reconstructed turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	42 ppm at 15 percent O_2 or 250 ng/J of useful output (2.0 lb/MWh).

Analysis: *Table 1 to Subpart KKKK* provides NOx emission standards based on combustion turbine type and heat input at peak rate. For a modified natural-gas fired turbine with a heat input at peak load of greater than 50 MMBtu/hr and less than or equal to 850 MMBtu/hr, the NOx emission limit is 42 ppmv at 15% O_2. As the turbines are expected to continue to meet the BACT limit of 2.0 ppmv at 15% O_2, compliance with this requirement is expected. Accordingly, an emissions limit of 42 PPMV NOx, pursuant to Subpart KKKK, will be added for the turbines on the facility permit in the "Emissions and Requirements" column.

§60.4330 What emission limits must I meet for sulfur dioxide (SO_2)?

(a) If your turbine is located in a continental area, you must comply with either paragraph (a)(1), (a)(2), or (a)(3) of this section.

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

(2) You must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement;

(3) For each stationary combustion turbine burning at least 50 percent biogas on a calendar month basis….

Analysis*:* The 0.90 lbs/MWh is a stack limit that will require annual source testing pursuant to §60.4415. The 0.06 lb/MMBtu is a fuel based limit which will require fuel monitoring (§60.4360) or fuel supplier data (§60.4365). As discussed for §60.4365 below, natural-gas fired turbines are expected to be in compliance with the 0.06 lb/MMBtu limit. Accordingly, an emissions limit of 0.06 lb/MMBtu SO_2, pursuant to Subpart KKKK, will be added for the turbines on the facility permit in the "Emissions and Requirements" column.

§60.4333 What are my general requirements for complying with this subpart?

(a) You must operate and maintain your stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.

(b) ....

Analysis: The specific conditions for the turbines, control equipment, and CEMS required to ensure compliance with BACT and offset requirements will ensure compliance with these general requirements.

§60.4335 How do I demonstrate compliance for NO_X if I use water or steam injection?

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

(b) Alternatively, you may use continuous emission monitoring, as follows:

(1) Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_x monitor and a diluent gas (oxygen (O_2) or carbon dioxide (CO_2)) monitor, to determine the hourly NO_x emission rate in parts per million (ppm) or ….

Analysis: As the turbines are not equipped with water or steam injection, this section is not applicable.

§60.4340 How do I demonstrate continuous compliance for NO_X if I do not use water or steam injection?

(a) If you are not using water or steam injection to control NO_X emissions, you must perform annual performance tests in accordance with §60.4400 to demonstrate continuous compliance. If the NO_X emission result from the performance test is less than or equal to 75 percent of the NO_X emission limit for the turbine, you may reduce the frequency of subsequent performance tests to once every 2 years (no more than 26 calendar months following the previous performance test). If the results of any subsequent performance test exceed 75 percent of the NO_X emission limit for the turbine, you must resume annual performance tests.

(b) As an alternative, you may install, calibrate, maintain and operate one of the following continuous monitoring systems:

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

(2) Continuous parameter monitoring as follows:
- (i) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you must define parameters indicative of the unit's NO_X formation characteristics, and you must monitor these parameters continuously.
- (ii) For any lean premix stationary combustion turbine, you must continuously monitor the appropriate parameters to determine whether the unit is operating in low-NO_X mode.
- (iii) For any turbine that uses SCR to reduce NO_X emissions, you must continuously monitor appropriate parameters to verify the proper operation of the emission controls.
- (iv) For affected units that are also regulated under part 75 of this chapter, with state approval you can monitor the NO_X emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in §75.19, the requirements of this paragraph (b) may be met by performing the parametric monitoring described in section 2.3 of part 75 appendix E or in §75.19(c)(1)(iv)(H).

Analysis:
The turbines are subject to §60.4340 because it provides continuous compliance requirements for NO_X when post-combustion NOx control is used. Consequently, the two other alternatives, annual performance testing per §60.4340(a) or continuous parameter monitoring per §60.4340(b)(2), will not be required. As discussed for Subpart A above, condition H23.2 will be added to require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK.

§60.4345 What are the requirements for the continuous emission monitoring system equipment, if I choose to use this option?
If the option to use a NO_X CEMS is chosen:

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

[**Note:** PS 2, entitled "Performance Specification 2—Specifications and Test Procedures for SO_2 and NO_X Continuous Emission Monitoring Systems in Stationary Sources," provides requirements for:

1.0 Scope and Application, 1.1 Analytes, 1.2 Applicability, 2.0 Summary of Performance Specification, 3.0 Definitions, 4.0 Interferences [Reserved], 5.0 Safety, 6.0 Equipment and Supplies, 6.1 CEMS Equipment Specifications, 7.0 Reagents and Standards, 8.0 Performance Specification Test Procedure, 8.1 Installation and Measurement Location Specifications, 8.1.1 CEMS Installation, 8.1.2 CEMS Measurement Location, 8.1.2.1 Point CEMS, 8.1.2.2 Path CEMS, 8.1.3 Reference Method Measurement Location and Traverse Points, 8.2 Pretest Preparation, 8.3 Calibration Drift Test Procedure, 8.4 Relative Accuracy Test Procedure, 8.4.1 RA Test Period, 8.4.2 Reference Methods, 8.4.3 Sampling Strategy for RM Tests, 8.4.5 Correlation of RM and CEMS Data, 8.5 Reporting, 9.0 Quality Control [Reserved], 10.0 Calibration and Standardization [Reserved], 11.0 Analytical Procedure, 12.0 Calculations and Data Analysis, 13.0 Method Performance, 13.1 Calibration Drift Performance Specification, 13.2 Relative Accuracy Performance Specification, 14.0 Pollution Prevention [Reserved], 15.0 Waste Management [Reserved], 16.0 Alternative Procedures, 17.0 References, and 18.0 Tables, Diagrams, Flowcharts, and Validation Data.**]**

(b) As specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling,

analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

(c) Each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter [Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units] are acceptable for use under this subpart.

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

(e) The owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of appendix B to part 75 of this chapter [Quality Assurance and Quality Control Procedures].

[Note: Appendix F to Part 60, "Procedure 1. Quality Assurance Requirements For Gas Continuous Emission Monitoring Systems Used For Compliance Determination" provides requirements for:

1. Applicability and Principle
2. Definitions
3. QC Requirements
   Each source owner or operator must develop and implement a QC program. As a minimum, each QC program must include written procedures which should describe in detail, complete, step-by-step procedures and operations for each of the following activities:
   1. Calibration of CEMS.
   2. CD determination and adjustment of CEMS.
   3. Preventive maintenance of CEMS (including spare parts inventory).
   4. Data recording, calculations, and reporting.
   5. Accuracy audit procedures including sampling and analysis methods.
   6. Program of corrective action for malfunctioning CEMS.

4. Calibration Drift (CD) Assessment
5. Data Accuracy Assessment
   5.1 Auditing Requirements.

5.1.1 Relative Accuracy Test Audit (RATA).
5.2 Excessive Audit Inaccuracy.
5.3 Criteria for Acceptable QC Procedure.
6. Calculations for CEMS Data Accuracy
7. Reporting Requirements**]**

Analysis:
The existing NOx CEMS system is SCAQMD-certified for RECLAIM and EPA-approved for Acid Rain requirements. Bicent Response Letter, 5/17/18, items 11.a.i.aa & 11.a.i.bb state the existing CEMS system can comply with the monitoring requirements of Subpart KKKK, with Data Acquisition System (DAHS) modification provided by Teledyne Monitor Labs. Regarding §60.4345(c), each fuel flowmeter is installed, calibrated and operated according to each manufacturer's O&M manual(s). Regarding §60.4345(d), each watt meter, steam flow meter, and each pressure or temperature measurement device, if applicable, is installed, calibrated, maintained, and operated according to manufacturer's instructions. Regarding §60.4345(e), the current QA/QC meets RECLAIM and Acid Rain requirements and will be updated to meet Subpart KKKK requirements, as necessary.

For Subpart KKKK, condition H23.2 will be added to require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK.

For the Acid Rain program, condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

§60.4350 How do I use data from the continuous emission monitoring equipment to identify excess emissions?
For purposes of identifying excess emissions:

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

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from method 19 in appendix A of this part [Test Methods 19 through 25E]. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

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

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used

to identify excess emissions under this subpart. Periods where the missing data substitution procedures in subpart D of part 75 [Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units] are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

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

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit [limit is 42 ppm] or the following equation for units complying with the output based standard:

Analysis: Condition H23.2 will be added to require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK.

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

Analysis: The facility will be exempt from monitoring the total sulfur content of the fuel being fired in the turbine, pursuant to §60.4365(a), discussed below.

§60.4365 How can I be exempted from monitoring the total sulfur content of the fuel?
You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental

areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

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

Analysis:
The facility will be exempt from monitoring the total sulfur content of the fuel being fired in the turbines, pursuant to §60.4365(a).

SCAQMD Rule 431.1(c)(1) specifies: "A person shall not transfer, sell or offer for sale for use in the jurisdiction of the District natural gas containing sulfur compounds calculated as H_2S in excess of 16 parts per million by volume (ppmv)." This 16 ppmv sulfur limit is equivalent to 1.0 grain/100 SCF (0.0626285 grain/100 SCF per 1 ppm), which is significantly lower than the 20 grains/100 SCF limit required by §60.4365(a).

In addition, Southern California Gas Company, Tariff Rule No. 30—Transportation of Customer-Owned Gas, allows up to 0.75 gr. S/100 scf total sulfur, which is significantly lower than the 20 grains/100 SCF limit required by §60.4365(a).

§60.4375 What reports must I submit?

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

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

Analysis: §60.4375(a) is applicable because the turbines are required to continuously monitor emissions with a NOx CEMS in accordance with §60.4340(b)(1). §60.4375(b) is not applicable because annual performance tests in accordance with §60.4340(a) is not required because a NOx CEMS is selected as an alternative to the annual performance tests, pursuant to §60.4340(b)(1). Condition H23.2 will be added to require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK.

§60.4380 How are excess emissions and monitor downtime defined for NOX?
For the purpose of reports required under §60.7(c), periods of excess emissions and monitor downtime that must be reported are defined as follows:

(a) . . . .

(b) For turbines using continuous emission monitoring, as described in §§60.4335(b) and 60.4345:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320 [42 ppm at 15% O_2]. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

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

Analysis: Condition H23.2 will be added to require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK.

§60.4395 When must I submit my reports?
All reports required under §60.7(c) must be postmarked by the 30th day following the end of each 6-month period.

Analysis: Condition H23.2 will be added to require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK.

§60.4400 How do I conduct the initial and subsequent performance tests, regarding NO_X?

(a) You must conduct an initial performance test, as required in §60.8. Subsequent NO_x performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

(1) There are two general methodologies that you may use to conduct the performance tests. For each test run:

(i) Measure the NO_X concentration (in parts per million (ppm)), using EPA Method 7E or EPA Method 20 in appendix A of this part. For units complying with the output based standard …; or

(ii) Measure the NO_X and diluent gas concentrations, using either EPA Methods 7E and 3A, or EPA Method 20 in appendix A of this part. Concurrently measure the heat input to the unit….

(2) Sampling traverse points for NO_X and (if applicable) diluent gas are to be selected following EPA Method 20 or EPA Method 1 (non-particulate procedures), and sampled for equal time intervals.

(3) Notwithstanding paragraph (a)(2) of this section, you may test at fewer points than are specified in EPA Method 1 or EPA Method 20 in appendix A of this part if the following conditions are met:

. . . .

(b) The performance test must be done at any load condition within plus or minus 25 percent of 100 percent of peak load. You may perform testing at the highest achievable load point, if at least 75 percent of peak load cannot be achieved in practice. You must conduct three separate test runs for each performance test. The minimum time per run is 20 minutes.

. . . .

(5) If you elect to install a CEMS, the performance evaluation of the CEMS may either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit.

Analysis:

§60.4400(a) requires an initial performance test, pursuant to §60.8. §60.4400(b)(5) indicates that if a CEMS is installed, the performance evaluation of the CEMS may

either be conducted separately or (as described in §60.4405) as part of the initial performance test of the affected unit. As discussed under §60.4405 below, the performance evaluation of the CEMS will be conducted as part of the initial performance test for the turbines for the purposes of Subpart KKKK.

§60.4400(a) also requires subsequent NOx performance tests on an annual basis. Pursuant to §60.4340(b)(1), however, the installation of a NOx CEMS is an alternative to the subsequent performance tests required by §60.4340(a). Therefore, since a NOx CEMS will be required to be installed, Subpart KKKK will not require subsequent performance tests.

§60.4405 How do I perform the initial performance test if I have chosen to install a NO_X-diluent CEMS?

If you elect to install and certify a NO_X-diluent CEMS under §60.4345, then the initial performance test required under §60.8 may be performed in the following alternative manner:

(a) Perform a minimum of nine RATA reference method runs, with a minimum time per run of 21 minutes, at a single load level, within plus or minus 25 percent of 100 percent of peak load. The ambient temperature must be greater than 0 °F during the RATA runs.

(b) For each RATA run, concurrently measure the heat input to the unit using a fuel flow meter (or flow meters) and measure the electrical and thermal output from the unit.

(c) Use the test data both to demonstrate compliance with the applicable NO_X emission limit under §60.4320 and to provide the required reference method data for the RATA of the CEMS described under §60.4335.

(d) Compliance with the applicable emission limit in §60.4320 is achieved if the arithmetic average of all of the NO_X emission rates for the RATA runs, expressed in units of ppm or lb/MWh, does not exceed the emission limit.

Analysis:
Condition H23.2 will be added to require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK.

40 CFR 60 Subpart TTTT—Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units

The final rule entitled "Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Generating Units (*New Source Rule*)," 80 FR 64510 (October 23, 2015), was codified as 40 CFR Part 60, Subpart TTTT, and became effective on

10/23/15. The New Source Rule established national emission standards to limit emissions of carbon dioxide (CO2) from newly constructed, modified, and reconstructed affected fossil fuel-fired electric utility generating units (EGUs).

In order to comply with the Presidential Executive Order on Promoting Energy Independence and Economic Growth, signed by President Trump on 3/28/17, then-EPA Administrator Scott Pruitt issued the following Federal Register notice for the New Source Rule. The Review of the Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Generating Units, 82 FR 16330 (April 4, 2017) announced that the EPA is reviewing The New Source Rule and, if appropriate, will as soon as practicable and consistent with law, initiate reconsideration proceedings to suspend, revise or rescind this rule.

On December 6, 2018, EPA proposed amendments to Subpart TTTT in Review of Standards of Performance for Greenhouse Gas Emissions From New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units, 83 FR 65424 (12/20/2018), for which comments are due by 2/19/19. After further analysis and review, EPA proposed to determine that the best system of emission reduction (BSER) for newly constructed coal-fired units, is the most efficient demonstrated steam cycle in combination with the best operating practices. This proposed BSER would replace the determination from the 2015 rule, which identified the BSER as partial carbon capture and storage. The EPA is not proposing to amend and is not reopening the standards of performance for newly constructed or reconstructed stationary combustion turbines.

- **Applicability Requirements**

  §60.5509 Am I subject to this subpart?

  (a) Except as provided for in paragraph (b) of this section, the GHG standards included in this subpart apply to any stationary combustion turbine that commenced construction after January 8, 2014 or commenced reconstruction after June 18, 2014 that meets the relevant applicability conditions in paragraphs (a)(1) and (a)(2) of this section.

  (1) Has a base load rating greater than 260 GJ/h (250 MMBtu/h) of fossil fuel (either alone or in combination with any other fuel), and
  (2) Serves a generator capable of selling greater than 25 MW of electricity to a utility power distribution system.

  ***Analysis*:** As evaluated below, the exemptions in §60.5509(b) are not applicable to the MGS turbines. Therefore, the applicability pursuant to §60.5509(a) is evaluated as follows.

  §60.5580 defines "*base load rating"* to mean "the maximum amount of heat input (fuel) that an EGU can combust on a steady state basis, as determined by the physical design and characteristics of the EGU at ISO conditions…." ISO

conditions mean 15 deg C (59 °F) ambient temperature, 60% relative humidity, and 14.70 psia, which correspond to Case S14 (100% load, 59 ºF ambient). The base load rating will be 480.12 Btu/hr after the turbine upgrade (Siemens Table 1), which exceeds the applicability threshold of 250 MMBtu/hr. The generator rating will be 47.154 MW (Siemens Table 1), which exceeds the applicability threshold of 25 MW. Therefore, the turbines will be subject to Subpart TTTT if the construction of the turbines commenced after 1/8/14, or the reconstruction commenced after 6/18/14

40 CFR 60 Subpart A—General Provisions provides definitions for "commenced," "construction" and "reconstruction," as shown below.

- **§60.2 Definitions**
  Commenced means, with respect to the definition of *new source* in section 111(a)(2) of the Act, that an owner or operator has undertaken a continuous program of construction or modification or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction or modification.

  Construction means fabrication, erection, or installation of an affected facility.

- **§60.15 Reconstruction**
  (b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:

    (1) The fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility, and

    (2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

  (c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

The turbines will not be subject to Subpart TTTT after the turbine upgrade. The construction of the turbines will not commence after the 1/8/14 applicability date, as the construction commenced prior to 2005. In addition, the turbine upgrade project will commence after the 1/8/14 applicability date, but the project does not meet the definition of "reconstruction." Bicent Response Letter, 5/17/18, item 12, states the upgrade cost is approximately $2M per turbine, and a complete turbine package, including the upgrade, is approximately $19M per turbine. As the $2M for the

upgrade does not exceed the 50% of the $19M for a new turbine, the upgrade is not a "reconstruction." Therefore, the turbines will not be subject to Subpart TTTT.

(b) You are not subject to the requirements of this subpart if your affected EGU meets any of the conditions specified in paragraphs (b)(1) through (b)(10) of this section.

(1) Your EGU is a steam generating unit or IGCC that is currently and always has been subject to a federally enforceable permit condition limiting annual net-electric sales to no more than one-third of its potential electric output or 219,000 MWh, whichever is greater.

(2) Your EGU is capable of combusting 50 percent or more non-fossil fuel and is also subject to a federally enforceable permit condition limiting the annual capacity factor for all fossil fuels combined of 10 percent (0.10) or less.

(3) Your EGU is a combined heat and power unit that is subject to a federally enforceable permit condition limiting annual net-electric sales to no more than the product of the unit's net design efficiency and the unit's potential electric output or 219,000 MWh, whichever is greater.

(4) Your EGU serves a generator along with other steam generating unit(s), IGCC, or stationary combustion turbine(s) where the effective generation capacity (determined based on a prorated output of the base load rating of each steam generating unit, IGCC, or stationary combustion turbine) is 25 MW or less.

(5) Your EGU is a municipal waste combustor that is subject to subpart Eb of this part.

(6) Your EGU is a commercial or industrial solid waste incineration unit that is subject to subpart CCCC of this part.

(7) Your EGU is a steam generating unit or IGCC that undergoes a modification resulting in an hourly increase in CO2 emissions (mass per hour) of 10 percent or less (2 significant figures). Modified units that are not subject to the requirements of this subpart pursuant to this subsection continue to be existing units under section 111 with respect to CO2 emissions standards.

(8) Your EGU is a stationary combustion turbine that is not capable of combusting natural gas (e.g., not connected to a natural gas pipeline).

(9) The proposed Washington County EGU project….

(10) The proposed Holcomb EGU project….

***Analysis*:** The definitions of "steam generating unit," "integrated gasification combined cycle facility or IGCC," and "combined heat and power unit" are as provided in §60.5580 below.

> **§60.5580 What definitions apply to this subpart?**
> "Steam generating unit" means "any furnace, boiler, or other device used for combusting fuel and producing steam (nuclear steam generators are not included) plus any integrated equipment that provides electricity or useful thermal output to the affected EGU(s) or auxiliary equipment."
>
> "Integrated gasification combined cycle facility or IGCC" means "a combined cycle facility that is designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas, plus any integrated equipment that provides electricity or useful thermal output to the affected EGU or auxiliary equipment."
>
> "Combined heat and power unit or CHP unit, (also known as "cogeneration")" means "an electric generating unit that that use a steam generating unit or stationary combustion turbine to simultaneously produce both electric (or mechanical) and useful thermal output from the same primary energy source."

The exemptions in §60.5509(b) do not apply to the MGS turbines. A stationary combustion turbine does not qualify as a "steam generating unit" an "IGCC," or a "combined heat and power unit," as defined in §60.5580.

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

§63.6080 What is the purpose of subpart YYYY?

Subpart YYYY establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emissions from stationary combustion turbines located at major sources of HAP emissions, and requirements to demonstrate initial and continuous compliance with the emission and operating limitations.

§63.6085 Am I subject to this subpart?

You are subject to this subpart if you own or operate a stationary combustion turbine located at a major source of HAP emissions.

(a) Stationary combustion turbine means all equipment, including but not limited to the turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), and any ancillary components and sub-components comprising any simple cycle

stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, the combustion turbine portion of any stationary cogeneration cycle combustion system, or the combustion turbine portion of any stationary combined cycle steam/electric generating system. Stationary means that the combustion turbine is not self propelled or intended to be propelled while performing its function, although it may be mounted on a vehicle for portability or transportability. Stationary combustion turbines covered by this subpart include simple cycle stationary combustion turbines, regenerative/recuperative cycle stationary combustion turbines, cogeneration cycle stationary combustion turbines, and combined cycle stationary combustion turbines. Stationary combustion turbines subject to this subpart do not include turbines located at a research or laboratory facility, if research is conducted on the turbine itself and the turbine is not being used to power other applications at the research or laboratory facility.

(b) A major source of HAP emissions is a contiguous site under common control that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site.

§63.6175 What definitions apply to this subpart?

Area source means any stationary source of HAP that is not a major source as defined in this part.

Analysis:

Actual and potential to emit HAPS emissions are evaluated below to determine whether the facility is a major source.

- **Actual Emissions**

  For the 2017 reporting year, the facility reported the following HAPs emissions.

Table 46--Toxic Pollutants, Reporting Year 2017

Pollutant ID	Pollutant Description	Annual Emissions, lb/yr
106990	1,3-Butadiene	2.429
~~7664417~~	~~Ammonia~~ ***NOT A HAP***	~~49771.132~~
7440382	Arsenic	0.00
71432	Benzene	66.809
7440439	Cadmium	0.000
18540299	Chromium (VI)	0.000
50000	Formaldehyde	3942.302 = **1.97 TPY**
7439921	Lead (inorganic)	0.001
91203	Naphthalene	7.228
7440020	Nickel	0.000

1151	PAHs, total, with components not reported	5.006
	TOTAL HAPS	4023.77 lb/yr = **2.01 TPY**

For the most recent reported year of 2017, the HAPs emissions for the highest single HAP (formaldehyde) was 1.97 tpy, and the total HAPS emissions were 2.01 tpy.

- **Facility Potential to Emit**
  The facility potential to emit emissions are calculated below by summing the potential to emit emissions for the individual equipment.

  1. Combined-Cycle Turbines
     From *Table 13--Toxic Air Contaminants/Hazardous Air Pollutants per Turbine* above:

     HAPs = (1.9447 tpy/ turbine) (2 turbines) = 3.8894 tpy

  2. Cooling Tower
     From *Table 14--Toxic Air Contaminants/Hazardous Air Pollutants for Cooling Tower* above:

     HAPs = 0.031 tpy

  3. Fire Pump
     From A/N 482576, see emissions calculations above:

     HAPs (diesel PM) = 0.0034 tpy

  4. Facility Total
     3.8894 tpy (two turbines) + 0.031 tpy (cooling tower) + 0.0034 tpy (fire pump) = 3.9238 tpy

     - **Conclusion**
       The facility is an area source and not a major source of HAPS. The actual HAPS emissions for 2017 (a typical year) was 2.01 tpy, and the facility potential to emit HAPS, as calculated above, is 3.9238 tpy. This facility does not emit or have the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutant. Therefore, the two turbines are not subject to Subpart YYYY.

40 CFR Part 64 – Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) rule, 40 CFR Part 64, specifies the monitoring, reporting, and recordkeeping criteria that is required to be conducted by Title V facilities to demonstrate ongoing compliance with emission limitations and standards. The rule is intended to provide reasonable assurance that facilities comply with emissions limitations by monitoring the operation and maintenance of their control devices.

In general, CAM applies to emissions units that meet all of the following conditions:

- the unit is located at a major source for which a Title V permit is required: and
- the unit is subject to an emission limitation or standard; and
- the unit uses a control device to achieve compliance with a federally enforceable limit or standard; and
- the unit has potential pre-control emissions (Title V renewal) or post-control emissions (initial Title V or revision) of at least 100% of the major source amount; and
- the unit is not otherwise exempt from CAM.

Analysis:

- The combined-cycle turbines are located at a major source for which a Title V permit is required as confirmed by *Table 18—New Source Review Major Polluting Facility Applicability* above.
- The turbines are subject to BACT limits for NOx, CO, and VOC.
- Each turbine is controlled with an SCR to meet the BACT limits for NOx and with a CO catalyst to meet the BACT limits for CO and VOC.

- Each turbine has potential pre-control emissions (Title V renewal) of at least 100% of the major source amount for NOx, CO, and VOC. The first Title V renewal application, A/N 561415, was submitted on 3/4/14. The current Title V renewal permit term runs from 11/3/15 to 11/2/20. For the Title V renewal, the applicability of CAM was evaluated. CAM is more likely to be found applicable during Title V renewal because applicability is based on potential pre-control emissions, instead of potential post-control emissions applicable to an initial Title V permit or a revision.

  The potential pre-control emissions at the time of the most recent Title V renewal are derived below for NOx, CO, and VOC, with reference to the information provided in this evaluation. From *Table 15 - Facility Maximum Annual Emissions, Pre-Modification* above, the potential post-control emissions per turbine at the time of the Title V renewal were 20.25 tpy NOx, 22.90 tpy CO, and 9.71 tpy VOC. From **A/N 394164 & 394165—Emissions Calculations, R1 and R2 Calculations** above: (1) NOx, R1 = 22 ppm & R2 = 2 ppm, (2) CO, R1 = 6 ppm & R2 = 2 ppm, (3) VOC, R1 = 3.6 ppm & R2 = 1.2 ppm.

  Pre-control NOx per turbine: (20.25 tpy) (22 ppm/2 ppm) = 222.75 tpy > 10 tpy

  Pre-control CO per turbine: (22.90 tpy) (6 ppm/2 ppm) = 68.7 tpy > 50 tpy

Pre-control VOC per turbine: (9.71 tpy) (3.6 ppm/2 ppm) = 17.48 tpy > 10 tpy

Note: SCAQMD BACT for VOC is 2 ppm at 15% O_2, 1-hour average, based on District Method 25.3/modified Method 25.3, as set forth in condition A195.3.

The pre-control NOx, CO, and VOC emissions per turbine are at least 100% of the respective major source thresholds.

- The turbines are exempt from CAM for NOx and CO pursuant to 40 CFR Part 64.2(b)(1)(vi). For each turbine, a NO_X continuous emission monitoring system (CEMS) and a CO CEMS are installed and operating. The NOx CEMS is certified in accordance with Rule 2012 requirements, and the CO CEMS is certified in accordance with Rule 218 requirements. 40 CFR Part 64.2(b)(1)(vi) provides that the requirements of this part shall not apply to an emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method, as defined in §64.1. §64.1 defines "continuous compliance determination method" to mean "a method, specified by the applicable standard or an applicable permit condition, which: (1) Is used to determine compliance with an emission limitation or standard on a continuous basis, consistent with the averaging period established for the emission limitation or standard; and (2) Provides data either in units of the standard or correlated directly with the compliance limit." Since the NOx CEMS and the CO CEMS qualify as continuous compliance determination methods, the two CEMS provide an exemption from CAM for NOx and CO.

- Because VOC BACT limit is achieved with the assistance of the oxidation catalyst, the turbines are subject to CAM for VOC. The oxidation catalyst is primarily installed to control CO emissions, but also controls VOC emissions to a minor degree. The CO catalyst is located at the outlet of the turbine and designed to provide the required control efficiency at the expected turbine exhaust temperature range. There are no operational requirements for the CO catalyst. To assure that the catalyst is not exhausted, each turbine is required to be source tested every three years for VOC pursuant to condition D29.2.

CAM applicability is summarized in the table below.

Table 47 – CAM Applicability

Equipment (device no.)	Subject to Emission Limitation or Standard	Use of External Control Device to Achieve Compliance with Limitation	Potential Pre-Control Emissions of at Least 100% of the Major Source Amount	Exemption	Applicability & Compliance Requirements
Gas Turbine No. 1 (D27)	CO: 2 ppmv	YES	YES > 50 TPY	CEMS[1]	NO
	NOx: 2 ppmv	YES	YES > 10 TPY	CEMS[1]	NO
	VOC: 2 ppmv	YES	YES > 10 TPY		YES Condition D29 requires source test every three years.
	PM: 3.386 lb/hr	NO			NO
	SOx: 0.06 lb/MMBtu	NO			NO
Gas Turbine No. 2 (D36)	CO: 2 ppmv	YES	YES > 50 TPY	CEMS[1]	NO
	NOx: 2 ppmv	YES	YES > 10 TPY	CEMS[1]	NO
	VOC: 2 ppmv	YES	YES > 10 TPY		YES Condition D29.2 requires source test every three years.
	PM: 3.386 lb/hr	NO			NO
	SOx: 0.06 lb/MMBtu	NO			NO

[1] The turbine is equipped with Continuous Emission Monitoring System (CEMS) for NOx pursuant to Rule 2012 and a CEMS for CO pursuant to Rule 218. Under 40 CFR §64.2(b)(vi), emission limitations or standards for which a part 70 or 71 permit specifies a continuous compliance determination method are exempt from CAM. Therefore, the CAM requirements do not apply to the turbines for NOx and CO.

Regulation XXXI—Acid Rain Permit Program (40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 - Acid Rain Provisions)

The Acid Rain Program (ARP), established under Title IV of the 1990 Clean Air Act (CAA Amendments) requires major emission reductions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x), the primary precursors of acid rain, from the power sector. The SO_2 program sets a permanent cap on the total amount of SO_2 that may be emitted by electric generating units (EGUs) in the contiguous United States. The program was phased in, with the final 2010 SO_2 cap set at 8.95 million tons, a level of about one-half of the emissions from the power sector in 1980. NO_x reductions under the ARP are achieved through a program that applies to a subset of coal-fired EGUs and is closer to a traditional, rate-based regulatory system. Since the program began in 1995, the ARP has achieved significant emission reductions. (See https://www.epa.gov/airmarkets/acid-rain-program.)

An allowance authorizes a utility or industrial source to emit 1 ton of emissions during a given compliance period. Allowances are fully marketable commodities. Once allocated, allowances may be bought, sold, traded, or banked for use in future years. Allowances can be allocated in several ways under the cap on emissions. EPA allocates allowances for the Acid Rain Program based on a rate of SO_2 emissions (in lbs/million British thermal units) and a baseline fuel consumption. Allowances can be bought directly from a company or individual who holds them. They can also be bought through a broker or through an environmental group that "retires" allowances so they can't be used to cover emissions. Additionally, SO_2 allowances under the Acid Rain Program can be bought at EPA's Annual SO_2 Allowance Auction. (See https://www.epa.gov/airmarkets/clean-air-markets-allowance-markets.)

The SCAQMD adopted *40 CFR Part 72—Permits Regulation* by reference in Regulation XXXI - Acid Rain Permit Program.

Part 72—Permits Regulation
Subpart A—Acid Rain Program General Provisions
§72.1 Purpose and Scope

(a) *Purpose.* The purpose of this part is to establish certain general provisions and the operating permit program requirements for affected sources and affected units under the Acid Rain Program, pursuant to title IV of the Clean Air Act, 42 U.S.C. 7401, *et seq.*, as amended by Public Law 101-549 (November 15, 1990).

§72.2 Definitions

The terms used in this part, in parts 73, 74, 75, 76, 77 and 78 of this chapter shall have the meanings set forth in the Act, including sections 302 and 402 of the Act, and in this section as follows:

Continuous emission monitoring system or CEMS means the equipment required by part 75 of this chapter used to sample, analyze, measure, and provide, by means of readings recorded at least once every 15 minutes (using an automated data acquisition and handling system (DAHS)), a permanent record of SO_2, NO_X, or CO_2 emissions or stack gas volumetric flow rate. The following are the principal types of continuous emission monitoring systems required under part 75 of this chapter. Sections 75.10 through 75.18, and §75.71(a) of this chapter indicate which type(s) of CEMS is required for specific applications:

(1) A sulfur dioxide monitoring system…;

(2) A flow monitoring system, consisting of a stack flow rate monitor and an automated DAHS. A flow monitoring system provides a permanent, continuous record of stack gas volumetric flow rate, in units of standard cubic feet per hour (scfh);

(3) A nitrogen oxides (NO_X) emission rate (or NO_X-diluent) monitoring system, consisting of a NO_X pollutant concentration monitor, a diluent gas (CO_2 or O_2) monitor, and an automated

DAHS. A NO_X-diluent monitoring system provides a permanent, continuous record of: NO_X concentration in units of parts per million (ppm), diluent gas concentration in units of percent O_2 or CO_2 (% O_2 or CO_2), and NO_X emission rate in units of pounds per million British thermal units (lb/mmBtu);

(4) A nitrogen oxides concentration monitoring system, consisting of a NO_X pollutant concentration monitor and an automated DAHS. A NO_X concentration monitoring system provides a permanent, continuous record of NO_X emissions in units of parts per million (ppm). This type of CEMS is used only in conjunction with a flow monitoring system to determine NO_X mass emissions (in lb/hr) under subpart H of part 75 of this chapter;

(5) A carbon dioxide monitoring system…; and

(6) A moisture monitoring system….

Gas-fired means:
(1) For all purposes under the Acid Rain Program, except for part 75 of this chapter, the combustion of:
(i) Natural gas or other gaseous fuel (including coal-derived gaseous fuel), for at least 90.0 percent of the unit's average annual heat input during the previous three calendar years and for at least 85.0 percent of the annual heat input in each of those calendar years; and
(ii) Any fuel, except coal or solid or liquid coal-derived fuel, for the remaining heat input, if any.

New unit means a unit that commences commercial operation on or after November 15, 1990, including any such unit that serves a generator with a nameplate capacity of 25 MWe or less or that is a simple combustion turbine.

Utility unit means a unit owned or operated by a utility:
(1) That serves a generator in any State that produces electricity for sale….

§72.6 Applicability
(a) Each of the following units shall be an affected unit, and any source that includes such a unit shall be an affected source, subject to the requirements of the Acid Rain Program:
(3) A utility unit, except a unit under paragraph (b) of this section, that:
(i) Is a new unit; or….

Analysis: The MGS is currently subject to the Acid Rain Program. The reasons are that the turbines are utility units because they provide power to the Vernon Public Utilities (ID 14502) and are new units because they commenced commercial operation on or after November 15, 1990. The exemptions provided in paragraph (b) are not applicable.

§72.9 Standard requirements

(a) *Permit Requirements.*

(2) The owners and operators of each affected source and each affected unit at the source shall:

(i) Operate the unit in compliance with a complete Acid Rain permit application or a superseding Acid Rain permit issued by the permitting authority; and

(ii) Have an Acid Rain Permit.

Analysis: The current facility permit indicates in the "Emissions and Requirements" column that the SO_2 from the turbines are subject to 40 CFR 72 – Acid Rain Provisions, and the requirements are listed in *Appendix B: Rule Emission Limits* of the facility permit. For the upgrade project, NOx will be added to the "Emissions and Requirements" column as subject to 40 CFR 72 –Acid Rain Provisions.

In Appendix B of the facility permit, the facility permit provides twenty-three standard conditions, which are produced below under the appropriate rule sections. From Appendix B, the first standard condition is for 40 CFR Part 70—State Operating Permit Programs. For completeness, the condition is reproduced below.

1. A Title V permit revision is not required for emission increases that are authorized by allowances acquired under the Acid Rain Program, provided that the increases do not trigger a Title V permit revision under any other applicable requirement. [70.6(a)(4)(ii)]

(b) *Monitoring Requirements.*

Analysis: From Appendix B, the applicable standard conditions are reproduced below:

2. The owners and operators and, to the extent applicable, the designated representative of each affected source and each affected unit at the source shall comply with the monitoring requirements as provided in 40 CFR Parts 74, 75, and 76. [40 CFR 72.50, 72.31, 72.9(b)(1)]

3. The emission measurements recorded and reported in accordance with 40 CFR Part 75 shall be used to determine compliance by the unit with the acid rain emissions limitations and emissions reduction requirements for sulfur dioxide (SO_2) under the Acid Rain Program. [40 CFR 72.9(b)(2), 40 CFR 75.2]

4. The requirements of 40 CFR Parts 74 and 75 shall not affect the responsibility of the operator to monitor emissions of other pollutants or other emissions characteristics at the unit under other applicable requirements and other provisions of this permit. [40 CFR 72.9(b)(3), 40 CFR 72.5]

(c) *Sulfur Dioxide Requirements.*

Analysis: From Appendix B of the facility permit, the applicable standard conditions are reproduced below:

5. The owners and operators of each source and each affected unit at the source shall: (A) Hold Allowances, as of the allowance transfer deadline, in the unit's compliance subaccount (after deductions under 40 CFR Part 73, Section 73.34(C)) not less than the total annual emissions of SO2 for the previous calendar year from the unit; and

   (B) Comply with the applicable acid rain emissions limitations for SO_2. [40 CFR 72.9(c)(ii)]

6. Each ton of SO_2 emitted in excess of the acid rain emissions limitations for sulfur dioxide shall constitute a separate violation of the Act. [40 CFR 72.9(g)(7)]

7. SO_2 allowances shall be held in, deducted from, or transferred among allowance tracking system accounts in accordance with the Acid Rain Program. [40 CFR 72.9(g)(4)]

8. A SO_2 allowance shall not be deducted in order to comply with the requirements under paragraph 41(A) of the SO_2 requirements prior to the calendar year for which the allowance was allocated. [40 CFR 72.9(g)(5)]

9. An affected unit shall be subject to the SO_2 requirements under the Acid Rain Program as follows: [40 CFR 72.6(a)]

   (A) Starting January 1, 2000, an affected unit under 40 CFR Part 72, Section 72.6(a)(2); or [40 CFR 72.6(a)(2)]

   (B) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 40 CFR Part 72, Section 72.6(a)(3). [40 CFR 72.6(a)(3)]

10. An allowance allocated by the EPA administrator under the Acid Rain Program is a limited authorization to emit SO_2 in accordance with the Acid Rain Program. No provision of the Acid Rain Program, the acid rain permit application, the acid rain permit, or the written exemption under 40 CFR Part 72, Sections 72.7, 72.8, or 72.14, and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization. [40 CFR 72.9(c)(6)]

11. An allowance allocated by the EPA Administrator under the Acid Rain Program does not constitute a property right. [40 CFR 72.9(c)(7)]

(d) *Nitrogen Oxides Requirements.* The owners and operators of the source and each affected unit at the source shall comply with the applicable Acid Rain emissions limitation for nitrogen oxides.

Analysis: As discussed under *Part 76--Acid Rain Nitrogen Oxides Emission Reduction Program* below, Part 76 is applicable to coal-fired utility units only. Therefore, this part is not applicable to the gas-fired turbines under evaluation.

(e) *Excess Emissions Requirements.*

Analysis: From Appendix B of the facility permit, the applicable standard conditions are reproduced below:

12. The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77. [40 CFR 72.9(e)]

13. The owners and operators of an affected unit that has excess emissions in any calendar year shall: [40 CFR 72.9(e)(2)]

    (A) Pay without demand the penalty required, and pay upon demand the interest on that penalty, as required by 40 CFR Part 77; and [40 CFR 72.9(e)(2)(i)]

    (B) Comply with the terms of an approved offset plan, as required by 40 CFR Part 77. [40 CFR 72.9(e)(2)(ii)]

(f) *Recordkeeping and Reporting Requirements.*

Analysis: From Appendix B of the facility permit, the applicable standard conditions are reproduced below:

14. Unless otherwise provided, the owners and operators of the source and each affected unit at the source that are subject to the acid rain provisions under Title IV shall keep on site at the source each of the following documents for a period of five years from the date the document is created. This period may be extended for cause, at any time prior to the end of five years, in writing by the EPA Administrator or the Executive Officer: [40 CFR 72.9(f)(1)]

    (A) The certificate of representation for the designated representative for the source and each affected unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR 72.24;

provided that the certificate and documents shall be retained on site at the source beyond such five year period until such documents are superseded because of the submission of a new certification of representation changing the designated representative; [40 CFR 72.9(f)(1)(i)]

(B) All emissions monitoring information, in accordance with 40 CFR Part 75; [40 CFR 72.9(f)(1)(i)]

(C) Copies of all reports, compliance certifications, and other submissions and all records made or required under the Acid Rain Program; and [40 CFR 72.9(f)(1)(iii)]

(D) Copies of all documents used to complete an acid rain permit application and any other submission under the Acid Rain Program or to demonstrate compliance with the requirements of the Acid Rain Program. [40 CFR 72.9(f)(1)(iv)]

15. The designated representative of an affected source and each affected unit at the source shall submit the reports and compliance certifications required under the Acid Rain Program, including those under 40 CFR Part 72 Subpart I and 40 CFR Part 75. [40 CFR 72.9(f)(2)]

(g) *Liability*

Analysis: From Appendix B of the facility permit, the applicable standard conditions are reproduced below:

16. Any person who knowingly violates any requirement or prohibition of the Acid Rain Program, a complete acid rain permit application, an acid rain permit, or a written exemption under 40 CFR Part 72, Sections 72.7, 72.8, or 72.14, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to Section 113(c) of the Act. [40 CFR 72.9(g)(1)]

17. Any person, who knowingly makes a false, material statement in any record, submission, or report under the Acid Rain Program shall be subject to criminal enforcement pursuant to Section 113(c) of the Act and 18 U.S.C. 1001. [40 CFR 72.9(g)(2)]

18. No permit revision shall excuse any violation of the requirements of the Acid Rain Program that occurs prior to the date that the revision takes effect. [40 CFR 72.9(g)(3)]

19. Each affected source and each affected unit shall meet the requirements of the Acid Rain Program. [40 CFR 72.9(g)(4)]

20. Any provision of the Acid Rain Program that applies to an affected source (including a provision applicable to the designated representative of an affected source) shall also

apply to the owners and operator of such source and of the affected units at the source. [40 CFR 72.9(g)(5)]

21. Any provision of the Acid Rain Program that applies to an affected unit (including a provision applicable to the designated representative of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR Part 72, Section 72.44 (Phase II repowering extension plans) and 40 CFR Part 76, Section 76.11 (NOx averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR Part 75, Sections 75.16, 75.17, and 75.18), the owners and operators and the designated representative of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the designated representative and that is located at a source of which they are not owners or operators or the designated representative. [40 CFR 72.9(g)(6)]

22. Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or designated representative of such source or unit, shall be a separate violation of the Act. [40 CFR 72.9(g)(7)]

(h) *Effect on Other Authorities*

Analysis: From Appendix B of the facility permit, the applicable standard conditions are reproduced below:

23. No provision of the Acid Rain Program, an acid rain permit application, an acid rain permit, or a written exemption under 40 CFR Part 72, Sections 72.7, 72.8, or 72.14 shall be construed as: [40 CFR 72.9(h)]

    (A) Except as expressly provided in Title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of Title I of the Act relating to applicable National Ambient Air Quality Standards or state implementation plans; [40 CFR 72.9(h)(1)]

    (B) Limiting the number of allowances a unit can hold; *provided*, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the Act; [40 CFR 72.9(h)(2)]

    (C) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law; [40 CFR 62.9(h)(3)]

    (D) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or [40 CFR 72.9(h)(4)]

(E) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established. [40 CFR 72.9(h)(5)]

Analysis: P. 1-40 of the Application states that MGS will submit updated applications for inclusion to the Acid Rain program and allowance system. Bicent Response Letter, 5/17/18, item 10.a.i. clarifies that the facility is currently in compliance with all Acid Rain Requirements.

Part 73—Sulfur Dioxide Allowance System
Subpart A—Background and Summary
§73.2 Applicability
The following parties shall be subject to the provisions of this part:

(a) Owners, operators, and designated representatives of affected sources and affected units pursuant to §72.6 of this chapter;

Subpart B—Allowance Allocations
§73.10 Initial allocations for Phase I and Phase II

(a) *Phase I allowances.* The Administrator will allocate allowances to the compliance account for each source that includes a unit listed in table 1 of this section in the amount listed in column A to be held for the years 1995 through 1999….

(b) *Phase II allowances.*
(1) The Administrator will allocate allowances to the compliance account for each source that includes a unit listed in table 2 of this section in the amount specified in table 2 column C to be held for the years 2000 through 2009.
(2) The Administrator will allocate allowances to the compliance account for each source that includes a unit listed in table 2 of this section in the amount specified in table 2 column F to be held for the years 2010 and each year thereafter.

Analysis: The Administrator allocated allowances to the existing units listed in tables 1 and 2, but is not allocating allowances to new utility units. Bicent is required to purchase SOx allowances as required, as described in *Part 73, Subpart C—Allowance Tracking System, Subpart D—Allowance Transfers, and Subpart E—Auctions, Direct Sales, And Independent Power Producers Written Guarantee.*

Note: In Bicent Response Letter, 10/20/18, item 4.c.iii.aa -bb, the applicant confirmed that the Application is proposing to increase the operating hours per month per turbine from 645.8 hr/month to 720 hr/month. Consequently, the existing SOx limit in condition A63.3 will be increased from 214 lb/month to 227 lb/month for two turbines. The response to item 4.c.iii.cc indicated the small increase in SO2 emissions will have no effect on the

facility acid rain permit. Bicent will forward notification of the increase to the EPA (Acid Rain Program division), and any increase in allowances that are needed to cover the increase will be acquired by Bicent as part of its normal allowance acquisition process.

PART 75—CONTINUOUS EMISSION MONITORING

Subpart A—General

§75.1 Purpose and scope

(a) *Purpose.* The purpose of this part is to establish requirements for the monitoring, recordkeeping, and reporting of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) emissions, volumetric flow, and opacity data from affected units under the Acid Rain Program pursuant to sections 412 and 821 of the CAA, 42 U.S.C. 7401-7671q as amended by Public Law 101-549 (November 15, 1990) [the Act]….

(b) *Scope.*

(1) The regulations established under this part include general requirements for the installation, certification, operation, and maintenance of continuous emission or opacity monitoring systems and specific requirements for the monitoring of SO_2 emissions, volumetric flow, NO_X emissions, opacity, CO_2 emissions and SO_2 emissions removal by qualifying Phase I technologies. Specifications for the installation and performance of continuous emission monitoring systems, certification tests and procedures, and quality assurance tests and procedures are included in appendices A [Specifications and Test Procedures] and B [Quality Assurance and Quality Control Procedures] to this part. Criteria for alternative monitoring systems and provisions to account for missing data from certified continuous emission monitoring systems or approved alternative monitoring systems are also included in the regulation.

(2) Statistical estimation procedures for missing data are included in appendix C to this part [Missing Data Estimation Procedures]. Optional protocols for estimating SO_2 mass emissions from gas-fired or oil-fired units and NO_X emissions from gas-fired peaking or oil-fired peaking units are included in appendices D [Optional SO_2 Emission Data Protocol for Gas-Fired and Oil-Fired Units] and E [Optional NOx Emissions Estimation Protocol for Gas-Fired Peaking Units and Oil-Fired Peaking Units], respectively, to this part. Requirements for recording and recordkeeping of monitoring data and for quarterly electronic reporting also are specified. Procedures for conversion of monitoring data into units of the standard are included in appendix F to this part [Conversion Procedures]. Procedures for the monitoring and calculation of CO_2 emissions are included in appendix G of this part [Determination of CO_2 Emissions].

§75.2 Applicability

(a) Except as provided in paragraphs (b) and (c) of this section, the provisions of this part apply to each affected unit subject to Acid Rain emission limitations or reduction requirements for SO_2 or NO_X.

Analysis: The turbines, as new utility units, are affected units under §72.6(a)(3)(i).

§75.4 Compliance dates

(a) … In accordance with §75.20, the owner or operator of each existing affected unit shall ensure that all monitoring systems required by this part for monitoring SO_2, NO_X, CO_2, opacity, moisture and volumetric flow are installed and that all certification tests are completed no later than the following dates (except as provided in paragraphs (d) through (i) of this section…

(b) In accordance with §75.20, the owner or operator of each new affected unit shall ensure that all monitoring systems required under this part for monitoring of SO_2, NO_X, CO_2, opacity, and volumetric flow are installed and all certification tests are completed on or before the later of the following dates:

(1) January 1, 1995, except that for a gas-fired unit or oil-fired unit located in an ozone nonattainment area or the ozone transport region, the date for installation and completion of all certification tests for NO_X and CO_2 monitoring systems shall be July 1, 1995 and for a gas-fired unit or an oil-fired unit not located in an ozone nonattainment area or the ozone transport region, the date for installation and completion of all certification tests for NO_X and CO_2 monitoring systems shall be January 1, 1996; or

(2) 180 calendar days after the date the unit commences commercial operation, notice of which date shall be provided under subpart G of this part.

(j) If the certification tests required under paragraph (b) or (c) of this section have not been completed by the applicable compliance date, the owner or operator shall determine and report SO_2 concentration, NO_X emission rate, CO_2 concentration, and flow rate data for all unit operating hours after the applicable compliance date in this paragraph until all required certification tests are successfully completed using either:

(1) The maximum potential concentration of SO_2, as defined in section 2.1.1.1 of appendix A to this part, the maximum potential NO_X emission rate, as defined in §72.2 of this chapter, the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, or the maximum potential CO_2 concentration, as defined in section 2.1.3.1 of appendix A to this part;

(2) Reference methods under §75.22(b); or

(3) Another procedure approved by the Administrator pursuant to a petition under §75.66.

Analysis:
Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75. Bicent Response Letter, 5/17/18, items 10.a.i., b.i, c.i. indicate that the facility is currently in compliance with all Acid Rain requirements. The facility's *Continuous Emissions Monitoring System Quality Assurance/Quality Control (QA/QC) Plan* sets forth separate requirements for the RECLAIM and Acid Rain Programs. For example, the NOx and O2 acid rain monitors are subject to the 40 CFR 75 and Rule 2012 Appendices and Chapters. The CEMS relative accuracy for NO_X ppm, NO_X lb/hr, O_2 percent concentration, and stack flow dscfm are regulated under the RECLAIM Rule 2012 requirements. The relative accuracy for NO_X lb/MMBtu is regulated under 40 CFR 75, Appendix A section 3.3 requirements. Thus NOx is separately monitored under both the requirements of the RECLAIM and the Acid Rain Programs. Both monitoring systems comply with the applicable requirements for each program individually.

Subpart B—Monitoring Provisions

§75.10 General operating requirements

(a) *Primary Measurement Requirement.* The owner or operator shall measure opacity, and all SO_2, NO_X, and CO_2 emissions for each affected unit as follows:

(1) To determine SO_2 emissions, the owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a SO_2 continuous emission monitoring system and a flow monitoring system with an automated data acquisition and handling system for measuring and recording SO_2 concentration (in ppm), volumetric gas flow (in scfh), and SO_2 mass emissions (in lb/hr) discharged to the atmosphere, except as provided in §§75.11 [specific provisions for monitoring SO_2 emissions] and 75.16 [special provisions for monitoring emissions from common, bypass, and multiple stacks for SO_2 emissions and heat input determinations] and subpart E of this part [alternative monitoring systems];

Analysis: Because the turbines are fired on natural gas only, a SOx CEMS will not be required. The operator shall measure and record SO_2 emissions by using the applicable procedures specified in appendix D to this part for estimating hourly SO_2 mass emissions, an alternative provided by §75.11(d)(2). These applicable procedures estimate SO_2 mass emissions based on the sulfur content of the fuel and the amount of fuel combusted.

Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75, as discussed above.

(2) To determine NO_X emissions, the owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a NO_X-diluent continuous emission monitoring system (consisting of a NO_X pollutant concentration monitor and an O_2 or CO_2 diluent gas monitor) with an automated data acquisition and handling system for measuring and recording NO_X concentration (in ppm), O_2 or CO_2 concentration (in percent O_2 or CO_2) and NO_X emission rate (in lb/mmBtu) discharged to the atmosphere, except as provided in §§75.12 [specific provisions for monitoring NOx emission rate] and 75.17 [specific provisions for monitoring emissions from common, bypass, and multiple stacks for NO_X emission rate] and subpart E of this part [alternative monitoring systems]. The owner or operator shall account for total NO_X emissions, both NO and NO_2, either by monitoring for both NO and NO_2 or by monitoring for NO only and adjusting the emissions data to account for NO_2;

Analysis: Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

(3) The owner or operator shall determine CO2 emissions by using one of the following options, except as provided in §75.13 and subpart E of this part:

(i) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a CO2 continuous emission monitoring system and a flow monitoring system with an automated data acquisition and handling system for measuring and recording CO2 concentration (in ppm or percent), volumetric gas flow (in scfh), and CO2 mass emissions (in tons/hr) discharged to the atmosphere;

(ii) The owner or operator shall determine CO2 emissions based on the measured carbon content of the fuel and the procedures in appendix G of this part [Determination of CO2 Emissions] to estimate CO2 emissions (in ton/day) discharged to the atmosphere; or

(iii) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a flow monitoring system and a CO2 continuous emission monitoring system that uses an O2 concentration monitor to determine CO2 emissions (according to the procedures in appendix F of this part) with an automated data acquisition and handling system for measuring and recording O2 concentration (in percent), CO2 concentration (in percent), volumetric gas flow (in scfh), and CO2 mass emissions (in tons/hr) discharged to the atmosphere;

Analysis: As the turbines are fired on natural gas only, a CO_2 CEMS is not required. Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

(4) The owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements in this part, a continuous opacity monitoring system with the automated data acquisition and handling system for measuring and recording the opacity of emissions (in percent opacity) discharged to the atmosphere, except as provided in §§75.14 and 75.18; and

Analysis: Pursuant to §75.14(c), the gas-fired turbines are exempt from the opacity monitoring requirements.

(5) A single certified flow monitoring system may be used to meet the requirements of paragraphs (a)(1) and (a)(3) of this section. A single certified diluent monitor may be used to meet the requirements of paragraphs (a)(2) and (a)(3) of this section. A single automated data acquisition and handling system may be used to meet the requirements of paragraphs (a)(1) through (a)(4) of this section.

(b) *Primary Equipment Performance Requirements.* The owner or operator shall ensure that each continuous emission monitoring system required by this part meets the equipment, installation, and performance specifications in appendix A to this part [Specifications and Test Procedures]; and is maintained according to the quality assurance and quality control procedures in appendix B to this part [Quality Assurance and Quality Control Procedures]; and shall record SO_2 and NO_X emissions in the appropriate units of measurement (*i.e.*, lb/hr for SO_2 and lb/mmBtu for NO_X).

(c) *Heat Input Rate Measurement Requirement.* The owner or operator shall determine and record the heat input rate, in units of mmBtu/hr, to each affected unit for every hour or part of an hour any fuel is combusted following the procedures in appendix F to this part [Conversion Procedures].

(d) *Primary equipment hourly operating requirements.* The owner or operator shall ensure that all continuous emission and opacity monitoring systems required by this part are in operation and monitoring unit emissions or opacity at all times that the affected unit combusts any fuel except as provided in §75.11(e) and during periods of calibration, quality assurance, or preventive maintenance, performed pursuant to §75.21 and appendix B of this part, periods of repair, periods of backups of data from the data acquisition and handling system, or recertification performed pursuant to §75.20.… The owner or operator shall ensure that the following requirements are met:

(1) The owner or operator shall ensure that each continuous emission monitoring system is capable of completing a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-min interval. The owner or operator shall reduce all SO_2 concentrations, volumetric flow, SO_2 mass emissions, CO_2 concentration, O_2 concentration, CO_2 mass emissions (if applicable), NO_X concentration, and NO_X emission rate data collected by the monitors to hourly averages. Hourly averages shall be computed using at least one data point in each fifteen minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly average may be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) if data are unavailable as a result of the performance of calibration, quality assurance, or preventive maintenance activities pursuant to §75.21 and appendix B of this part [Quality Assurance and Quality Control Procedures], or backups of data from the data acquisition and handling system, or recertification, pursuant to §75.20. The owner or operator shall use all valid measurements or data points collected during an hour to calculate the hourly averages. All data points collected during an hour shall be, to the extent practicable, evenly spaced over the hour.

(3) Failure of an SO_2, CO_2, or O_2 emissions concentration monitor, NO_X concentration monitor, flow monitor, moisture monitor, or NO_X-diluent continuous emission monitoring system to acquire the minimum number of data points for calculation of an hourly average in paragraph (d)(1) of this section shall result in the failure to obtain a valid hour of data and the loss of such component data for the entire hour. For a NO_X-diluent monitoring system, an hourly average NO_X emission rate in lb/mmBtu is valid only if the minimum number of data points is acquired by both the NO_X pollutant concentration monitor and the diluent monitor (O_2 or CO_2). For a moisture monitoring system consisting of one or more oxygen analyzers capable of measuring O_2 on a wet-basis and a dry-basis, an hourly average percent moisture value is valid only if the minimum number of data points is acquired for both the wet-and dry-basis measurements. If a valid hour of data is not obtained, the owner or operator shall estimate and record emissions, moisture, or flow data for the missing hour by means of the automated data acquisition and handling system, in accordance with the applicable procedure for missing data substitution in subpart D of this part [Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units].

(f) *Minimum measurement capability requirement.* The owner or operator shall ensure that each continuous emission monitoring system is capable of accurately measuring, recording, and reporting data, and shall not incur an exceedance of the full scale range, except as provided in sections 2.1.1.5, 2.1.2.5, and 2.1.4.3 of appendix A to this part [Specifications and Test Procedures].

(g) *Minimum recording and recordkeeping requirements.* The owner or operator shall record and the designated representative shall report the hourly, daily, quarterly, and annual information collected under the requirements of this part as specified in subparts F [Conversion Procedures] and G [Determination of CO_2 Emissions] of this part.

Analysis: Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

§75.11 Specific provisions for monitoring SO_2 emissions.

(d) *Gas-fired and oil-fired units.* The owner or operator of an affected unit that qualifies as a gas-fired or oil-fired unit, as defined in §72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan, shall measure and record SO_2 emissions:

(1) By meeting the general operating requirements in §75.10 for an SO_2 continuous emission monitoring system and flow monitoring system. If this option is selected, the owner or operator shall comply with the applicable provisions in paragraph (e)(1), (e)(2), or (e)(3) of this section during hours in which the unit combusts only gaseous fuel;

(2) By providing other information satisfactory to the Administrator using the applicable procedures specified in appendix D to this part [Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil Fired Units] for estimating hourly SO_2 mass emissions; or

(3) By using the low mass emissions excepted methodology in §75.19(c) for estimating hourly SO_2 mass emissions if the affected unit qualifies as a low mass emissions unit under §75.19(a) and (b). If this option is selected for SO_2, the LME methodology must also be used for NO_X and CO_2 when these parameters are required to be monitored by applicable program(s).

Analysis: Since the turbines are fired on natural gas only, a SOx CEMS will not be required. Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

§75.12 Specific provisions for monitoring NO_X emission rate

(a) *Coal-fired units, gas-fired nonpeaking units or oil-fired nonpeaking units.* The owner or operator shall meet the general operating requirements in §75.10 of this part for a NO_X continuous emission monitoring system (CEMS) for each affected coal-fired unit, gas-fired nonpeaking unit, or oil-fired nonpeaking unit, except as provided in paragraph (d) of this section, §75.17, and subpart E of this part. The diluent gas monitor in the NO_X-diluent CEMS may measure either O_2 or CO_2 concentration in the flue gases.

(c) *Determination of NO_X emission rate.* The owner or operator shall calculate hourly, quarterly, and annual NO_X emission rates (in lb/mmBtu) by combining the NO_X concentration (in ppm), diluent concentration (in percent O_2 or CO_2), and percent moisture (if applicable)

measurements according to the procedures in appendix F to this part [Conversion Procedures].

(d) *Gas-fired peaking units and oil-fired peaking units.…*

Analysis: Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

§75.13 Specific provisions for monitoring CO_2 emissions.

(a) *CO_2 continuous emission monitoring system.* If the owner or operator chooses to use the continuous emission monitoring method, then the owner or operator shall meet the general operating requirements in §75.10 for a CO_2 continuous emission monitoring system and flow monitoring system for each affected unit. The owner or operator shall comply with the applicable provisions specified in §§75.11(a) through (e) or §75.16, except that the phrase "CO_2 continuous emission monitoring system" shall apply rather than "SO_2 continuous emission monitoring system," the phrase "CO_2 concentration" shall apply rather than "SO_2 concentration," the term "maximum potential concentration of CO_2" shall apply rather than "maximum potential concentration of SO_2," and the phrase "CO_2 mass emissions" shall apply rather than "SO_2 mass emissions."

(b) *Determination of CO_2 emissions using appendix G to this part* [Determination of CO_2 Emissions]. If the owner or operator chooses to use the appendix G method, then the owner or operator shall follow the procedures in appendix G to this part for estimating daily CO_2 mass emissions based on the measured carbon content of the fuel and the amount of fuel combusted. For units with wet flue gas desulfurization systems or other add-on emissions controls generating CO_2, the owner or operator shall use the procedures in appendix G to this part to estimate both combustion-related emissions based on the measured carbon content of the fuel and the amount of fuel combusted and sorbent-related emissions based on the amount of sorbent injected. The owner or operator shall calculate daily, quarterly, and annual CO_2 mass emissions (in tons) in accordance with the procedures in appendix G to this part.

(c) *Determination of CO_2 mass emissions using an O_2 monitor according to appendix F to this part* [Conversion Procedures]…

Analysis: As the turbines are fired on natural gas only, a CO_2 CEMS is not required. Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

§75.14 Specific provisions for monitoring opacity

(a) *Coal-fired units and oil-fired units….*

(b) *Unit with wet flue gas pollution control system*….

(c) *Gas-fired units.* The owner or operator of an affected unit that qualifies as gas-fired, as defined in §72.2 of this chapter, based on information submitted by the designated representative in the monitoring plan is exempt from the opacity monitoring requirements of this part. Whenever a unit previously categorized as a gas-fired unit is recategorized as another type of unit by changing its fuel mix, the owner or operator shall install, operate, and certify a continuous opacity monitoring system as required by paragraph (a) of this section by December 31 of the following calendar year.

Analysis: Pursuant to §75.14(c), the gas-fired turbines are exempt from the opacity monitoring requirements.

Subpart C—Operation and Maintenance Requirements

§75.20 Initial certification and recertification procedures

(a) *Initial certification approval process.* The owner or operator shall ensure that each continuous emission or opacity monitoring system required by this part meets the initial certification requirements of this section and shall ensure that all applicable initial certification tests under paragraph (c) of this section are completed by the deadlines specified in §75.4 and prior to use in the Acid Rain Program. In addition, whenever the owner or operator installs a continuous emission or opacity monitoring system in order to meet the requirements of §§75.11 through 75.18, where no continuous emission or opacity monitoring system was previously installed, initial certification is required.

(1) *Notification of initial certification test dates.* The owner or operator or designated representative shall submit a written notice of the dates of initial certification testing at the unit as specified in §75.61(a)(1).

(2) *Certification application.* The owner or operator shall apply for certification of each continuous emission or opacity monitoring system used under the Acid Rain Program. The owner or operator shall submit the certification application in accordance with §75.60 and each complete certification application shall include the information specified in §75.63.

(3) *Provisional approval of certification (or recertification) applications.* Upon the successful completion of the required certification (or recertification) procedures of this section, each continuous emission or opacity monitoring system shall be deemed provisionally certified (or recertified) for use under the Acid Rain Program for a period not to exceed 120 days following receipt by the Administrator of the complete certification (or recertification) application under paragraph (a)(4) of this section. Notwithstanding this paragraph, no continuous emission or opacity monitor systems for

a combustion source seeking to enter the Opt-in Program in accordance with part 74 of this chapter shall be deemed provisionally certified (or recertified) for use under the Acid Rain Program. Data measured and recorded by a provisionally certified (or recertified) continuous emission or opacity monitoring system, operated in accordance with the requirements of appendix B to this part [Quality Assurance and Quality Control Procedures], will be considered valid quality-assured data (retroactive to the date and time of provisional certification or recertification), provided that the Administrator does not invalidate the provisional certification (or recertification) by issuing a notice of disapproval within 120 days of receipt by the Administrator of the complete certification (or recertification) application. Note that when the conditional data validation procedures of paragraph (b)(3) of this section are used for the initial certification (or recertification) of a continuous emissions monitoring system, the date and time of provisional certification (or recertification) of the CEMS may be earlier than the date and time of completion of the required certification (or recertification) tests.

(4) *Certification (or recertification) application formal approval process.* The Administrator will issue a notice of approval or disapproval of the certification (or recertification) application to the owner or operator within 120 days of receipt of the complete certification (or recertification) application. In the event the Administrator does not issue such a notice within 120 days of receipt, each continuous emission or opacity monitoring system which meets the performance requirements of this part and is included in the certification (or recertification) application will be deemed certified (or recertified) for use under the Acid Rain Program.

(i) *Approval notice.* If the certification (or recertification) application is complete and shows that each continuous emission or opacity monitoring system meets the performance requirements of this part, then the Administrator will issue a notice of approval of the certification (or recertification) application within 120 days of receipt.

(ii) *Incomplete application notice.* A certification (or recertification) application will be considered complete when all of the applicable information required to be submitted in §75.63 has been received by the Administrator, the EPA Regional Office, and the appropriate State and/or local air pollution control agency. If the certification (or recertification) application is not complete, then the Administrator will issue a notice of incompleteness that provides a reasonable timeframe for the designated representative to submit the additional information required to complete the certification (or recertification) application. If the designated representative has not complied with the notice of incompleteness by a specified due date, then the Administrator may issue a notice of disapproval specified under paragraph (a)(4)(iii) of this section. The 120-day review period shall not begin prior to receipt of a complete application.

(iii) *Disapproval notice.* If the certification (or recertification) application shows that any continuous emission or opacity monitoring system does not meet the performance requirements of this part, or if the certification (or recertification) application is incomplete and the requirement for disapproval under paragraph (a)(4)(ii) of this section has been met, the Administrator shall issue a written notice of disapproval of the certification (or recertification) application within 120 days of receipt. By issuing the notice of disapproval, the provisional certification (or recertification) is invalidated by the Administrator, and the data measured and recorded by each uncertified continuous emission or opacity monitoring system shall not be considered valid quality-assured data as follows: from the hour of the probationary calibration error test that began the initial certification (or recertification) test period (if the conditional data validation procedures of paragraph (b)(3) of this section were used to retrospectively validate data); or from the date and time of completion of the invalid certification or recertification tests (if the conditional data validation procedures of paragraph (b)(3) of this section were not used). The owner or operator shall follow the procedures for loss of initial certification in paragraph (a)(5) of this section for each continuous emission or opacity monitoring system which is disapproved for initial certification. For each disapproved recertification, the owner or operator shall follow the procedures of paragraph (b)(5) of this section.

(iv) *Audit decertification.* The Administrator may issue a notice of disapproval of the certification status of a continuous emission or opacity monitoring system, in accordance with §75.21.

(5) *Procedures for loss of certification.* When the Administrator issues a notice of disapproval of a certification application or a notice of disapproval of certification status (as specified in paragraph (a)(4) of this section), then:

(i) Until such time, date, and hour as the continuous emission monitoring system can be adjusted, repaired, or replaced and certification tests successfully completed (or, if the conditional data validation procedures in paragraphs (b)(3)(ii) through (b)(3)(ix) of this section are used, until a probationary calibration error test is passed following corrective actions in accordance with paragraph (b)(3)(ii) of this section), the owner or operator shall substitute the following values, as applicable, for each hour of unit operation during the period of invalid data specified in paragraph (a)(4)(iii) of this section or in §75.21: the maximum potential concentration of SO_2, as defined in section 2.1.1.1 of appendix A to this part, to report SO_2 concentration; the maximum potential NO_X emission rate, as defined in §72.2 of this chapter, to report NO_X emissions in lb/mmBtu; the maximum potential concentration of NO_X, as defined in section 2.1.2.1 of appendix A to this part, to report NO_X emissions in ppm (when a NO_X concentration monitoring system is used to determine NO_X mass emissions, as defined under §75.71(a)(2));

the maximum potential flow rate, as defined in section 2.1.4.1 of appendix A to this part, to report volumetric flow; the maximum potential concentration of CO_2, as defined in section 2.1.3.1 of appendix A to this part, to report CO_2 concentration data; and either the minimum potential moisture percentage, as defined in section 2.1.5 of appendix A to this part or, if Equation 19-3, 19-4 or 19-8 in Method 19 in appendix A to part 60 of this chapter is used to determine NO_X emission rate, the maximum potential moisture percentage, as defined in section 2.1.6 of appendix A to this part; and

(ii) The designated representative shall submit a notification of certification retest dates as specified in §75.61(a)(1)(ii) and a new certification application according to the procedures in paragraph (a)(2) of this section; and

(iii) The owner or operator shall repeat all certification tests or other requirements that were failed by the continuous emission or opacity monitoring system, as indicated in the Administrator's notice of disapproval, no later than 30 unit operating days after the date of issuance of the notice of disapproval.

(b) *Recertification approval process*

(c) *Initial certification and recertification procedures.* Prior to the deadline in §75.4, the owner or operator shall conduct initial certification tests and in accordance with §75.63, the designated representative shall submit an application to demonstrate that the continuous emission or opacity monitoring system and components thereof meet the specifications in appendix A to this part [Specifications and Test Procedures]. The owner or operator shall compare reference method values with output from the automated data acquisition and handling system that is part of the continuous emission monitoring system being tested. Except as otherwise specified in paragraphs (b)(1), (d), and (e) of this section, and in sections 6.3.1 and 6.3.2 of appendix A to this part, the owner or operator shall perform the following tests for initial certification or recertification of continuous emission or opacity monitoring systems or components according to the requirements of appendix A to this part:

(1) For each SO_2 pollutant concentration monitor, each NO_X concentration monitoring system used to determine NO_X mass emissions, as defined under §75.71(a)(2), and each NO_X-diluent continuous emission monitoring system:

(i) A 7-day calibration error test, where, for the NO_X -diluent continuous emission monitoring system, the test is performed separately on the NO_X pollutant concentration monitor and the diluent gas monitor;

(ii) A linearity check, where, for the NO_X-diluent continuous emission monitoring system, the test is performed separately on the NO_X pollutant concentration monitor and the diluent gas monitor;

(iii) A relative accuracy test audit. For the NO_X-diluent continuous emission monitoring system, the RATA shall be done on a system basis, in units of

lb/mmBtu. For the NO_X concentration monitoring system, the RATA shall be done on a ppm basis;

(iv) A bias test;

(v) A cycle time test, (where, for the NO_X-diluent continuous emission monitoring system, the test is performed separately on the NO_X pollutant concentration monitor and the diluent gas monitor); and

(2) For each flow monitor:

(i) A 7-day calibration error test;

(ii) Relative accuracy test audits, as follows:

(A) A single-load (or single-level) RATA at the normal load (or level), as defined in section 6.5.2.1(d) of appendix A to this part, for a flow monitor installed on a peaking unit or bypass stack, or for a flow monitor exempted from multiple-level RATA testing under section 6.5.2(e) of appendix A to this part;

(B) For all other flow monitors, a RATA at each of the three load levels (or operating levels) corresponding to the three flue gas velocities described in section 6.5.2(a) of appendix A to this part;

(iii) A bias test for the single-load (or single-level) flow RATA described in paragraph (c)(2)(ii)(A) of this section; and

(iv) A bias test (or bias tests) for the 3-level flow RATA described in paragraph (c)(2)(ii)(B) of this section, at the following load or operational level(s):

(A) At each load level designated as normal under section 6.5.2.1(d) of appendix A to this part, for units that produce electrical or thermal output, or

(B) At the operational level identified as normal in section 6.5.2.1(d) of appendix A to this part, for units that do not produce electrical or thermal output.

(10) For the automated data acquisition and handling system, tests designed to verify:

(i) Proper computation of hourly averages for pollutant concentrations, flow rate, pollutant emission rates, and pollutant mass emissions; and

(ii) Proper computation and application of the missing data substitution procedures in subpart D of this part [Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units] and the bias adjustment factors in section 7 of appendix A to this part.

(11) The owner or operator shall provide adequate facilities for initial certification or recertification testing that include:

(i) Sampling ports adequate for test methods applicable to such facility, such that:

(A) Volumetric flow rate, pollutant concentration, and pollutant emission rates can be accurately determined by applicable test methods and procedures; and

(B) A stack or duct free of cyclonic flow during performance tests is available, as demonstrated by applicable test methods and procedures.

(ii) Basic facilities (e.g., electricity) for sampling and testing equipment.

Analysis: Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

§75.21 Quality assurance and quality control requirements

(a) *Continuous emission monitoring systems.* The owner or operator of an affected unit shall operate, calibrate and maintain each continuous emission monitoring system used to report emission data under the Acid Rain Program as follows:

(1) The owner or operator shall operate, calibrate and maintain each primary and redundant backup continuous emission monitoring system according to the quality assurance and quality control procedures in appendix B of this part [Quality Assurance and Quality Control Procedures].

(2) The owner or operator shall ensure that each non-redundant backup CEMS meets the quality assurance requirements of §75.20(d) for each day and quarter that the system is used to report data.

(c) *Calibration gases.* The owner or operator shall ensure that all calibration gases used to quality assure the operation of the instrumentation required by this part shall meet the definition in §72.2 of this chapter.

(d) *Notification for periodic relative accuracy test audits.* The owner or operator or the designated representative shall submit a written notice of the dates of relative accuracy testing as specified in §75.61.

(f) *Requirements for Air Emission Testing.* On and after March 27, 2012, relative accuracy testing under §75.74(c)(2)(ii), section 6.5 of appendix A to this part, and section 2.3.1 of appendix B to this part, and stack testing under §75.19 and section 2.1 of appendix E to this part shall be performed by an "Air Emission Testing Body", as defined in §72.2 of this chapter. Conformance to the requirements of ASTM D7036-04 (incorporated by reference, see §75.6), referred to in section 6.1.2 of appendix A to this part, shall apply only to these tests. Section 1.1.4 of appendix B to this part, and section 2.1 of appendix E to this part require compliance with section 6.1.2 of appendix A to this part. Tests and activities under this part not required to be performed by an AETB as defined in §72.2 of this chapter include daily CEMS operation, daily calibration error checks, daily flow interference checks, quarterly linearity checks, routine maintenance of CEMS, voluntary emissions testing, or emissions testing required under other regulations.

Analysis: Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

§75.22 Reference test methods

(a) The owner or operator shall use the following methods, which are found in appendices A-1 through A-4 to part 60 of this chapter, to conduct the following tests: Monitoring system tests for certification or recertification of continuous emission monitoring Systems; NO_X emission tests of low mass emission units under §75.19(c)(1)(iv); NO_X emission tests of excepted monitoring systems under appendix E to this part; and required quality assurance and quality control tests:

(1) Methods 1 or 1A are the reference methods for selection of sampling site and sample traverses.

(2) Method 2 or its allowable alternatives, as provided in appendix A to part 60 of this chapter, except for Methods 2B and 2E, are the reference methods for determination of volumetric flow.

(3) Methods 3, 3A, or 3B are the reference methods for the determination of the dry molecular weight O_2 and CO_2 concentrations in the emissions.

(4) Method 4 (either the standard procedure described in section 8.1 of the method or the moisture approximation procedure described in section 8.2 of the method) shall be used to correct pollutant concentrations from a dry basis to a wet basis (or from a wet basis to a dry basis) and shall be used when relative accuracy test audits of continuous moisture monitoring systems are conducted. For the purpose of determining the stack gas molecular weight, however, the alternative wet bulb-dry bulb technique for approximating the stack gas moisture content described in section 2.2 of Method 4 may be used in lieu of the procedures in sections 8.1 and 8.2 of the method.

(5) Methods 6, 6A, 6B or 6C, and 7, 7A, 7C, 7D or 7E in appendix A-4 to part 60 of this chapter, as applicable, are the reference methods for determining SO_2 and NO_X pollutant concentrations. (Methods 6A and 6B in appendix A-4 to part 60 of this chapter may also be used to determine SO_2 emission rate in lb/mmBtu.) Methods 7, 7A, 7C, 7D, or 7E in appendix A-4 to part 60 of this chapter must be used to measure total NO_X emissions, both NO and NO_2, for purposes of this part. The owner or operator shall not use the following sections, exceptions, and options of method 7E in appendix A-4 to part 60 of this chapter:

(i) Section 7.1 of the method allowing for use of prepared calibration gas mixtures that are produced in accordance with method 205 in Appendix M of 40 CFR Part 51;

(ii) The sampling point selection procedures in section 8.1 of the method, for the emission testing of boilers and combustion turbines under appendix E to this part. The number and location of the sampling points for those applications shall be as specified in sections 2.1.2.1 and 2.1.2.2 of appendix E to this part;

(iii) Paragraph (3) in section 8.4 of the method allowing for the use of a multi-hole probe to satisfy the multipoint traverse requirement of the method;

(iv) Section 8.6 of the method allowing for the use of "Dynamic Spiking" as an alternative to the interference and system bias checks of the method. Dynamic spiking may be conducted (optionally) as an additional quality assurance check; and

(v) That portion of Section 8.5 of the method allowing multiple sampling runs to be conducted before performing the post-run system bias check or system calibration error check.

(6) Method 3A in appendix A-2 and method 7E in appendix A-4 to part 60 of this chapter are the reference methods for determining NO_X and diluent emissions from stationary gas turbines for testing under appendix E to this part.

(b) The owner or operator may use any of the following methods, which are found in appendices A-1 through A-4 to part 60 of this chapter, as a reference method backup monitoring system to provide quality-assured monitor data:

(1) Method 3A for determining O_2 or CO_2 concentration;

(2) Method 6C for determining SO_2 concentration;

(3) Method 7E for determining total NO_X concentration (both NO and NO_2);

(4) Method 2, or its allowable alternatives, as provided in appendix A to part 60 of this chapter, except for Methods 2B and 2E, for determining volumetric flow. The sample point(s) for reference methods shall be located according to the provisions of section 6.5.5 of appendix A to this part.

(c)

(1) Instrumental EPA Reference Methods 3A, 6C, and 7E in appendices A-2 and A-4 of part 60 of this chapter shall be conducted using calibration gases as defined in section 5 of appendix A to this part. Otherwise, performance tests shall be conducted and data reduced in accordance with the test methods and procedures of this part unless the Administrator:

(i) Specifies or approves, in specific cases, the use of a reference method with minor changes in methodology;

(ii) Approves the use of an equivalent method; or

(iii) Approves shorter sampling times and smaller sample volumes when necessitated by process variables or other factors.

(2) Nothing in this paragraph shall be construed to abrogate the Administrator's authority to require testing under Section 114 of the Act.

Analysis: Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

§75.23 Alternatives To Standards Incorporated By Reference

(a) The designated representative of a unit may petition the Administrator for an alternative to any standard incorporated by reference and prescribed in this part in accordance with §75.66(c).

§75.24 Out-of-control periods and adjustment for system bias

(a) If an out-of-control period occurs to a monitor or continuous emission monitoring system, the owner or operator shall take corrective action and repeat the tests applicable to the "out-of-control parameter" as described in appendix B of this part.
  (1) For daily calibration error tests, an out-of-control period occurs when the calibration error of a pollutant concentration monitor exceeds the applicable specification in section 2.1.4 of appendix B to this part.
  (2) For quarterly linearity checks, an out-of-control period occurs when the error in linearity at any of three gas concentrations (low, mid-range, and high) exceeds the applicable specification in appendix A to this part.
  (3) For relative accuracy test audits, an out-of-control period occurs when the relative accuracy exceeds the applicable specification in appendix A to this part.

(b) When a monitor or continuous emission monitoring system is out-of-control, any data recorded by the monitor or monitoring system are not quality-assured and shall not be used in calculating monitor data availabilities pursuant to §75.32 of this part.

(c) When a monitor or continuous emission monitoring system is out-of-control, the owner or operator shall take one of the following actions until the monitor or monitoring system has successfully met the relevant criteria in appendices A and B of this part as demonstrated by subsequent tests:
  (1) Apply the procedures for missing data substitution to emissions from affected unit(s); or
  (2) Use a certified backup monitoring system or a reference method for measuring and recording emissions from the affected unit(s); or
  (3) Adjust the gas discharge paths from the affected unit(s) with emissions normally observed by the out-of-control monitor or monitoring system so that all exhaust gases are monitored by a certified monitor or monitoring system meeting the requirements of appendices A and B of this part.

(d) When the bias test indicates that an SO_2 monitor, a flow monitor, a NO_X-diluent continuous emission monitoring system, or a NO_X concentration monitoring system used to determine NO_X mass emissions, as defined in §75.71(a)(2), is biased low (*i.e.*, the arithmetic mean of the differences between the reference method value and the monitor or monitoring system measurements in a relative accuracy test audit exceed the bias statistic in section 7 of appendix A to this part), the owner or operator shall adjust the monitor or continuous emission monitoring system to eliminate the cause of bias such that it passes the bias test or calculate and use the bias adjustment factor as specified in section 2.3.4 of appendix B to this part.

(e) The owner or operator shall determine if a continuous opacity monitoring system is out-of-control and shall take appropriate corrective actions according to the procedures specified for

State Implementation Plans, pursuant to appendix M of part 51 of this chapter. The owner or operator shall comply with the monitor data availability requirements of the State. If the State has no monitor data availability requirements for continuous opacity monitoring systems, then the owner or operator shall comply with the monitor data availability requirements as stated in the data capture provisions of appendix M, part 51 of this chapter.

Analysis: Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

Subpart D—Missing Data Substitution Procedures

§75.30 General provisions
§75.31 Initial missing data procedures
§75.32 Determination of monitor data availability for standard missing data procedures
§75.33 Standard missing data procedures for SO_2, NO_X, and flow rate
§75.34 Units with add-on emission controls
§75.35 Missing data procedures for CO_2
§75.36 Missing data procedures for heat input rate determinations.

Analysis: Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

Subpart E—Alternative Monitoring Systems

Not applicable.

Subpart F—Recordkeeping Requirements

§75.53 Monitoring plan

(a) *General provisions.*

(1) The provisions of paragraphs (e) and (f) of this section shall be met through December 31, 2008. The owner or operator shall meet the requirements of paragraphs (a), (b), (e), and (f) of this section through December 31, 2008, except as otherwise provided in paragraph (g) of this section. On and after January 1, 2009, the owner or operator shall meet the requirements of paragraphs (a), (b), (g), and (h) of this section only. In addition, the provisions in paragraphs (g) and (h) of this section that support a regulatory option provided in another section of this part must be followed if the regulatory option is used prior to January 1, 2009.

(2) The owner or operator of an affected unit shall prepare and maintain a monitoring plan. Except as provided in paragraphs (f) or (h) of this section (as applicable), a monitoring plan shall contain sufficient information on the continuous emission or opacity monitoring systems, excepted methodology under §75.19, or excepted monitoring systems under appendix D or E to this part and the use of data derived from these

systems to demonstrate that all unit SO_2 emissions, NO_X emissions, CO_2 emissions, and opacity are monitored and reported.

(b) Whenever the owner or operator makes a replacement, modification, or change in the certified CEMS, continuous opacity monitoring system, excepted methodology under §75.19, excepted monitoring system under appendix D or E to this part, or alternative monitoring system under subpart E of this part, including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to a serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan, by the applicable deadline specified in §75.62 or elsewhere in this part.

(c)-(d) [Reserved]

(e) *Contents of the monitoring plan.* Each monitoring plan shall contain the information in paragraph (e)(1) of this section in electronic format and the information in paragraph (e)(2) of this section in hardcopy format. Electronic storage of all monitoring plan information, including the hardcopy portions, is permissible provided that a paper copy of the information can be furnished upon request for audit purposes.

(1) *Electronic*

. . .

(2) *Hardcopy*

. . .

(g) *Contents of the monitoring plan.* The requirements of paragraphs (g) and (h) of this section shall be met on and after January 1, 2009. Notwithstanding this requirement, the provisions of paragraphs (g) and (h) of this section may be implemented prior to January 1, 2009, as follows. In 2008, the owner or operator may opt to record and report the monitoring plan information in paragraphs (g) and (h) of this section, in lieu of recording and reporting the information in paragraphs (e) and (f) of this section. Each monitoring plan shall contain the information in paragraph (g)(1) of this section in electronic format and the information in paragraph (g)(2) of this section in hardcopy format. Electronic storage of all monitoring plan information, including the hardcopy portions, is permissible provided that a paper copy of the information can be furnished upon request for audit purposes.

(1) *Electronic*

. . .

(2) *Hardcopy*

. . .

(h) *Contents of monitoring plan for specific situations.* The following additional information shall be included in the monitoring plan for the specific situations described:

(1) For each gas-fired unit or oil-fired unit for which the owner or operator uses the optional protocol in appendix D to this part for estimating heat input and/or SO_2 mass emissions, or for each gas-fired or oil-fired peaking unit for which the owner/operator uses the optional protocol in appendix E to this part for estimating NO_X emission rate (using a fuel flowmeter), the designated representative shall include the following additional information for each fuel flowmeter system in the monitoring plan:

(i) *Electronic*
. . .

(ii) *Hardcopy*
. . .

§75.57 General recordkeeping provisions

(a) *Recordkeeping requirements for affected sources.* The owner or operator of any affected source subject to the requirements of this part shall maintain for each affected unit a file of all measurements, data, reports, and other information required by this part at the source in a form suitable for inspection for at least three (3) years from the date of each record. Unless otherwise provided, throughout this subpart the phrase "for each affected unit" also applies to each group of affected or nonaffected units utilizing a common stack and common monitoring systems, pursuant to §§75.16 through 75.18, or utilizing a common pipe header and common fuel flowmeter, pursuant to section 2.1.2 of appendix D to this part. The file shall contain the following information:

(1) The data and information required in paragraphs (b) through (h) of this section, beginning with the earlier of the date of provisional certification or the deadline in §75.4(a), (b), or (c);

(2) The supporting data and information used to calculate values required in paragraphs (b) through (g) of this section, excluding the subhourly data points used to compute hourly averages under §75.10(d), beginning with the earlier of the date of provisional certification or the deadline in §75.4(a), (b), or (c);

(3) The data and information required in §75.58 for specific situations, beginning with the earlier of the date of provisional certification or the deadline in §75.4(a), (b), or (c);

(4) The certification test data and information required in §75.59 for tests required under §75.20, beginning with the date of the first certification test performed, the quality assurance and quality control data and information required in §75.59 for tests, and the quality assurance/quality control plan required under §75.21 and appendix B to this part, beginning with the date of provisional certification;

(5) The current monitoring plan as specified in §75.53, beginning with the initial submission required by §75.62;

(6) The quality control plan as described in section 1 of appendix B to this part, beginning with the date of provisional certification; and
(7) The information required by sections 6.1.2(b) and (c) of appendix A to this part.

(b) *Operating parameter record provisions.* The owner or operator shall record for each hour the following information on unit operating time, heat input rate, and load, separately for each affected unit and also for each group of units utilizing a common stack and a common monitoring system or utilizing a common pipe header and common fuel flowmeter:
(1) Date and hour;
(2) Unit operating time (rounded up to the nearest fraction of an hour (in equal increments that can range from one hundredth to one quarter of an hour, at the option of the owner or operator));
(3) Hourly gross unit load (rounded to nearest MWge) (or steam load in 1000 lb/hr at stated temperature and pressure, rounded to the nearest 1000 lb/hr, or mmBtu/hr of thermal output, rounded to the nearest mmBtu/hr, if elected in the monitoring plan);
(4) Operating load range corresponding to hourly gross load of 1 to 10, except for units using a common stack or common pipe header, which may use up to 20 load ranges for stack or fuel flow, as specified in the monitoring plan;
(5) Hourly heat input rate (mmBtu/hr, rounded to the nearest tenth);
(6) Identification code for formula used for heat input, as provided in §75.53; and
(7) For CEMS units only, F-factor for heat input calculation and indication of whether the diluent cap was used for heat input calculations for the hour.

(c) *SO_2 emission record provisions.* The owner or operator shall record for each hour the information required by this paragraph for each affected unit or group of units using a common stack and common monitoring systems, except as provided under §75.11(e) or for a gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in appendix D to this part or for a low mass emissions unit for which the owner or operator is using the optional low mass emissions methodology in §75.19(c) for estimating SO_2 mass emissions: ….

(d) *NO_X emission record provisions.* The owner or operator shall record the applicable information required by this paragraph for each affected unit for each hour or partial hour during which the unit operates, except for a gas-fired peaking unit or oil-fired peaking unit for which the owner or operator is using the optional protocol in appendix E to this part or a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in §75.19(c) for estimating NO_X emission rate. For each NO_X emission rate (in lb/mmBtu) measured by a NO_X-diluent monitoring system, or, if applicable, for each NO_X concentration (in ppm) measured by a NO_X concentration monitoring system used to calculate NO_X mass emissions under §75.71(a)(2), record the following data as measured and reported from the certified primary monitor, certified back-up monitor, or other approved method of emissions determination:

(1) Component-system identification code, as provided in §75.53 (including identification code for the moisture monitoring system, if applicable);
(2) Date and hour;
(3) Hourly average NO_X concentration (ppm, rounded to the nearest tenth) and hourly average NO_X concentration (ppm, rounded to the nearest tenth) adjusted for bias if bias adjustment factor required, as provided in §75.24(d);
(4) Hourly average diluent gas concentration (for NO_X-diluent monitoring systems, only, in units of percent O_2 or percent CO_2, rounded to the nearest tenth);
(5) If applicable, the hourly average moisture content of the stack gas (percent H_2O, rounded to the nearest tenth). If the continuous moisture monitoring system consists of wet- and dry-basis oxygen analyzers, also record both the hourly wet- and dry-basis oxygen readings (in percent O_2, rounded to the nearest tenth);
(6) Hourly average NO_X emission rate (for NO_X-diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth);
(7) Hourly average NO_X emission rate (for NO_X-diluent monitoring systems only, in units of lb/mmBtu, rounded to the nearest thousandth), adjusted for bias if bias adjustment factor is required, as provided in §75.24(d). The requirement to report hourly NO_X emission rates to the nearest thousandth shall not affect NO_X compliance determinations under part 76 of this chapter; compliance with each applicable emission limit under part 76 shall be determined to the nearest hundredth pound per million Btu;
(8) Percent monitoring system data availability (recorded to the nearest tenth of a percent), for the NO_X-diluent or NO_X concentration monitoring system, and, if applicable, for the moisture monitoring system, calculated pursuant to §75.32;
(9) Method of determination for hourly average NO_X emission rate or NO_X concentration and (if applicable) for the hourly average moisture percentage, using Codes 1-55 in Table 4a of this section; and
(10) Identification codes for emissions formulas used to derive hourly average NO_X emission rate and total NO_X mass emissions, as provided in §75.53, and (if applicable) the F-factor used to convert NO_X concentrations into emission rates.

(e) *CO_2 emission record provisions.* Except for a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in §75.19(c) for estimating CO_2 mass emissions, the owner or operator shall record or calculate CO_2 emissions for each affected unit using one of the following methods specified in this section:

(f) *Opacity records*

(g) *Diluent record provisions.* The owner or operator of a unit using a flow monitor and an O_2 diluent monitor to determine heat input, in accordance with Equation F-17 or F-18 of appendix F to this part, or a unit that accounts for heat input using a flow monitor and a CO_2 diluent monitor (which is used only for heat input determination and is not used as a CO_2

pollutant concentration monitor) shall keep the following records for the O_2 or CO_2 diluent monitor:

. . . .

(h) *Missing data records.* The owner or operator shall record the causes of any missing data periods and the actions taken by the owner or operator to correct such causes.

§75.58 General recordkeeping provisions for specific situations

The owner or operator shall meet all of the applicable recordkeeping requirements of this section.

(a) [Reserved]

(b) *Specific parametric data record provisions for calculating substitute emissions data for units with add-on emission controls.* In accordance with §75.34, the owner or operator of an affected unit with add-on emission controls shall either record the applicable information in paragraph (b)(3) of this section for each hour of missing SO_2 concentration data or NO_X emission rate (in addition to other information), or shall record the information in paragraph (b)(1) of this section for SO_2 or paragraph (b)(2) of this section for NO_X through an automated data acquisition and handling system, as appropriate to the type of add-on emission controls:

. . . .

(c) *Specific SO_2 emission record provisions for gas-fired or oil-fired units using optional protocol in appendix D to this part.* In lieu of recording the information in §75.57(c), the owner or operator shall record the applicable information in this paragraph for each affected gas-fired or oil-fired unit for which the owner or operator is using the optional protocol in appendix D to this part for estimating SO_2 mass emissions:

. . . .

§75.59 Certification, quality assurance, and quality control record provisions.

The owner or operator shall meet all of the applicable recordkeeping requirements of this section.

(a) *Continuous emission or opacity monitoring systems.* The owner or operator shall record the applicable information in this section for each certified monitor or certified monitoring system (including certified backup monitors) measuring and recording emissions or flow from an affected unit.

(1) For each SO_2 or NO_X pollutant concentration monitor, flow monitor, CO_2 emissions concentration monitor (including O_2 monitors used to determine CO_2 emissions), or diluent gas monitor (including wet- and dry-basis O_2 monitors used to determine percent moisture), the owner or operator shall record the following for all daily and 7-day calibration error tests, and all off-line calibration demonstrations, including any follow-up tests after corrective action:

. . . .

(2) For each flow monitor, the owner or operator shall record the following for all daily interference checks, including any follow-up tests after corrective action.

. . . .

(3) For each SO_2 or NO_X pollutant concentration monitor, CO_2 emissions concentration monitor (including O_2 monitors used to determine CO_2 emissions), or diluent gas monitor (including wet- and dry-basis O_2 monitors used to determine percent moisture), the owner or operator shall record the following for the initial and all subsequent linearity check(s), including any follow-up tests after corrective action.

. . . .

(4) For each differential pressure type flow monitor, the owner or operator shall record items in paragraphs (a)(4) (i) through (v) of this section, for all quarterly leak checks, including any follow-up tests after corrective action. For each flow monitor, the owner or operator shall record items in paragraphs (a)(4) (vi) and (vii) for all flow-to-load ratio and gross heat rate tests:

. . . .

5) For each SO_2 pollutant concentration monitor, flow monitor, each CO_2 emissions concentration monitor (including any O_2 concentration monitor used to determine CO_2 mass emissions or heat input), each NO_X-diluent continuous emission monitoring system, each NO_X concentration monitoring system, each diluent gas (O_2 or CO_2) monitor used to determine heat input, each moisture monitoring system, and each approved alternative monitoring system, the owner or operator shall record the following information for the initial and all subsequent relative accuracy test audits:

. . . .

(6) For each SO_2, NO_X, or CO_2 pollutant concentration monitor, each component of a NO_X-diluent continuous emission monitoring system, and each CO_2 or O_2 monitor used to determine heat input, the owner or operator shall record the following information for the cycle time test:

. . . .

(7) In addition to the information in paragraph (a)(5) of this section, the owner or operator shall record, for each relative accuracy test audit, supporting information sufficient to substantiate compliance with all applicable sections and appendices in this part. Unless otherwise specified in this part or in an applicable test method, the information in paragraphs (a)(7)(i) through (a)(7)(vi) of this section may be recorded either in hard copy format, electronic format or a combination of the two, and the owner or operator shall maintain this information in a format suitable for inspection and audit purposes.

This RATA supporting information shall include, but shall not be limited to, the following data elements:

. . . .

(8) For each certified continuous emission monitoring system, continuous opacity monitoring system, excepted monitoring system, or alternative monitoring system, the date and description of each event which requires certification, recertification, or certain diagnostic testing of the system and the date and type of each test performed. If the conditional data validation procedures of §75.20(b)(3) are to be used to validate and report data prior to the completion of the required certification, recertification, or diagnostic testing, the date and hour of the probationary calibration error test shall be reported to mark the beginning of conditional data validation.

(9) When hardcopy relative accuracy test reports, certification reports, recertification reports, or semiannual or annual reports for gas or flow rate CEMS are required or requested under §75.60(b)(6) or §75.63, the reports shall include, at a minimum, the following elements (as applicable to the type(s) of test(s) performed):

(b) *Excepted monitoring systems for gas-fired and oil-fired units.* The owner or operator shall record the applicable information in this section for each excepted monitoring system following the requirements of appendix D to this part or appendix E to this part for determining and recording emissions from an affected unit.

. . . .

(c) Except as otherwise provided in §75.58(b)(3)(i), for units with add-on SO_2 or NO_X emission controls following the provisions of §75.34(a)(1) or (a)(2), the owner or operator shall keep the following records on-site in the quality assurance/quality control plan required by section 1 of appendix B to this part:

(1) A list of operating parameters for the add-on emission controls, including parameters in §75.58(b), appropriate to the particular installation of add-on emission controls; and

(2) The range of each operating parameter in the list that indicates the add-on emission controls are properly operating.

(d) *Excepted monitoring for low mass emissions units under §75.19(c)(1)(iv).*

(e) *DAHS Verification.* For each DAHS (missing data and formula) verification that is required for initial certification, recertification, or for certain diagnostic testing of a monitoring system, record the date and hour that the DAHS verification is successfully completed. (This requirement only applies to units that report monitoring plan data in accordance with §75.53(g) and (h).)

Analysis: Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

Subpart G—Reporting Requirements

§75.60 General provisions

(a) The designated representative for any affected unit subject to the requirements of this part shall comply with all reporting requirements in this section and with the signatory requirements of §72.21 of this chapter for all submissions.

(b) *Submissions.* The designated representative shall submit all reports and petitions (except as provided in §75.61) as follows:

(1) *Initial certifications.* The designated representative shall submit initial certification applications according to §75.63.

(2) *Recertifications.* The designated representative shall submit recertification applications according to §75.63.

(3) *Monitoring plans.* The designated representative shall submit monitoring plans according to §75.62.

(4) *Electronic quarterly reports.* The designated representative shall submit electronic quarterly reports according to §75.64.

(5) *Other petitions and communications.* The designated representative shall submit petitions, correspondence, application forms, designated representative signature, and petition-related test results in hardcopy to the Administrator. Additional petition requirements are specified in §§75.66 and 75.67.

(6) *Semiannual or annual RATA reports.* If requested in writing (or by electronic mail) by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy RATA report within 45 days after completing a required semiannual or annual RATA according to section 2.3.1 of appendix B to this part, or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by §75.59(a)(9) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the RATA report.

(7) *Routine appendix E retest reports.* If requested in writing (or by electronic mail) by the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency, the designated representative shall submit a hardcopy report within 45 days after completing a required periodic retest according to section 2.2 of appendix E to this part, or within 15 days of receiving the request, whichever is later. The designated representative shall report the hardcopy information required by §75.59(b)(5) to the applicable EPA Regional Office, appropriate State, and/or appropriate local air pollution control agency that requested the hardcopy report.

(c) *Confidentiality of data.* The following provisions shall govern the confidentiality of information submitted under this part.

(1) All emission data reported in quarterly reports under §75.64 shall remain public information.

(2) For information submitted under this part other than emission data submitted in quarterly reports, the designated representative must assert a claim of confidentiality at the time of submission for any information he or she wishes to have treated as confidential business information (CBI) under subpart B of part 2 of this chapter. Failure to assert a claim of confidentiality at the time of submission may result in disclosure of the information by EPA without further notice to the designated representative.

(3) Any claim of confidentiality for information submitted in quarterly reports under §75.64 must include substantiation of the claim. Failure to provide substantiation may result in disclosure of the information by EPA without further notice.

(4) As provided under subpart B of part 2 of this chapter, EPA may review information submitted to determine whether it is entitled to confidential treatment even when confidentiality claims are initially received. The EPA will contact the designated representative as part of such a review process.

§75.61 Notifications

(a) *Submission.* The designated representative for an affected unit (or owner or operator, as specified) shall submit notice to the Administrator, to the appropriate EPA Regional Office, and to the applicable State and local air pollution control agencies for the following purposes, as required by this part.

(1) *Initial certification and recertification test notifications.* The owner or operator or designated representative for an affected unit shall submit written notification of initial certification tests and revised test dates as specified in §75.20 for continuous emission monitoring systems, for alternative monitoring systems under subpart E of this part, or for excepted monitoring systems under appendix E to this part, except as provided in paragraphs (a)(1)(iii), (a)(1)(iv) and (a)(4) of this section. The owner or operator shall also provide written notification of testing performed under §75.19(c)(1)(iv)(A) to establish fuel-and-unit-specific NO_X emission rates for low mass emissions units. Such notifications are not required, however, for initial certifications and recertifications of excepted monitoring systems under appendix D to this part.

(i) Notification of initial certification testing and full recertification. Initial certification test notifications and notifications of full recertification testing under §75.20(b)(2) shall be submitted not later than 21 days prior to the first scheduled day of certification or recertification testing. In emergency situations when full recertification testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means at least 7 days prior to the original scheduled test date or the revised test date, whichever is earlier.

(ii) *Notification of certification retesting, and partial recertification testing.* For retesting required following a loss of certification under §75.20(a)(5) or for partial recertification testing required under §75.20(b)(2), notice of the date of any required RATA testing or any required retesting under section 2.3 in appendix E to this part shall be submitted either in writing or by telephone at least 7 days prior to the first scheduled day of testing; except that in emergency situations when testing is required following an uncontrollable failure of equipment that results in lost data, notice shall be sufficient if provided within 2 business days following the date when testing is scheduled. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided by telephone or other means at least 2 business days prior to the original scheduled test date or the revised test date, whichever is earlier.

(iii) *Repeat of testing without notice.* Notwithstanding the above notice requirements, the owner or operator may elect to repeat a certification or recertification test immediately, without advance notification, whenever the owner or operator has determined during the certification or recertification testing that a test was failed or must be aborted, or that a second test is necessary in order to attain a reduced relative accuracy test frequency.

(iv) *Waiver from notification requirements.* The Administrator, the appropriate EPA Regional Office, or the applicable State or local air pollution control agency may issue a waiver from the notification requirement of paragraph (a)(1)(ii) of this section, for a unit or a group of units, for one or more recertification tests or other retests. The Administrator, the appropriate EPA Regional Office, or the applicable State or local air pollution control agency may also discontinue the waiver and reinstate the notification requirement of paragraph (a)(1)(ii) of this section for future recertification tests (or other retests) of a unit or a group of units.

(2) *New unit, newly affected unit, new stack, or new flue gas desulfurization system operation notification.* The designated representative for an affected unit shall submit written notification: For a new unit or a newly affected unit, of the planned date when a new unit or newly affected unit will commence commercial operation, or becomes affected, or, for new stack or flue gas desulfurization system, of the planned date when a new stack or flue gas desulfurization system will be completed and emissions will first exit to the atmosphere.

(i) Notification of the planned date shall be submitted not later than 45 days prior to the date the unit commences commercial operation or becomes affected, or not later than 45 days prior to the date when a new stack or flue gas desulfurization system exhausts emissions to the atmosphere.

(ii) If the date when the unit commences commercial operation or becomes affected, or the date when the new stack or flue gas desulfurization system exhausts emissions to the atmosphere, whichever is applicable, changes from the planned date, a notification of the actual date shall be submitted not later than 7 days following: The date the unit commences commercial operation or becomes

affected, or the date when a new stack or flue gas desulfurization system exhausts emissions to the atmosphere.

(3) *Unit shutdown and recommencement of commercial operation.*

(4) *Use of backup fuels for appendix E procedures.*

(5) *Periodic relative accuracy test audits, appendix E retests, and low mass emissions unit retests.* The owner or operator or designated representative of an affected unit shall submit written notice of the date of periodic relative accuracy testing performed under section 2.3.1 of appendix B to this part, of periodic retesting performed under section 2.2 of appendix E to this part, and of periodic retesting of low mass emissions units performed under §75.19(c)(1)(iv)(D), no later than 21 days prior to the first scheduled day of testing. Testing may be performed on a date other than that already provided in a notice under this subparagraph as long as notice of the new date is provided either in writing or by telephone or other means acceptable to the respective State agency or office of EPA, and the notice is provided as soon as practicable after the new testing date is known, but no later than twenty-four (24) hours in advance of the new date of testing.

(i) Written notification under paragraph (a) (5) of this section may be provided either by mail or by facsimile. In addition, written notification may be provided by electronic mail, provided that the respective State agency or office of EPA agrees that this is an acceptable form of notification.

(ii) Notwithstanding the notice requirements under paragraph (a)(5) of this section, the owner or operator may elect to repeat a periodic relative accuracy test, appendix E retest, or low mass emissions unit retest immediately, without additional notification whenever the owner or operator has determined that a test was failed, or that a second test is necessary in order to attain a reduced relative accuracy test frequency.

(iii) *Waiver from notification requirements.* The Administrator, the appropriate EPA Regional Office, or the applicable State air pollution control agency may issue a waiver from the requirement of paragraph (a)(5) of this section to provide notice to the respective State agency or office of EPA for a unit or a group of units for one or more tests. The Administrator, the appropriate EPA Regional Office, or the applicable State air pollution control agency may also discontinue the waiver and reinstate the requirement of paragraph (a)(5) of this section to provide notice to the respective State agency or office of EPA for future tests for a unit or a group of units. In addition, if an observer from a State agency or EPA is present when a test is rescheduled, the observer may waive all notification requirements under paragraph (a)(5) of this section for the rescheduled test.

(6) *Notice of combustion of emergency fuel under appendix D or E.*

(7) *Long-term cold storage and recommencement of commercial operation.*

(8) *Certification deadline date for new or newly affected units.* The designated representative of a new or newly affected unit shall provide notification of the date on which the relevant deadline for initial certification is reached, either as provided in §75.4(b) or §75.4(c), or as specified in a State or Federal SO_2 or NO_X mass emission reduction program that incorporates by reference, or otherwise adopts, the monitoring, recordkeeping, and reporting requirements of subpart F, G, or H of this part. The notification shall be submitted no later than 7 calendar days after the applicable certification deadline is reached.

(b) The owner or operator or designated representative shall submit notification of certification tests and recertification tests for continuous opacity monitoring systems as specified in §75.20(c)(8) to the State or local air pollution control agency.

(c) If the Administrator determines that notification substantially similar to that required in this section is required by any other State or local agency, the owner or operator or designated representative may send the Administrator a copy of that notification to satisfy the requirements of this section, provided the ORISPL unit identification number(s) is denoted.

§75.62 Monitoring plan submittals

(a) *Submission—*

(1) *Electronic.* Using the format specified in paragraph (c) of this section, the designated representative for an affected unit shall submit a complete, electronic, up-to-date monitoring plan file (except for hardcopy portions identified in paragraph (a)(2) of this section) to the Administrator as follows: no later than 21 days prior to the initial certification tests; at the time of each certification or recertification application submission; and (prior to or concurrent with) the submittal of the electronic quarterly report for a reporting quarter where an update of the electronic monitoring plan information is required, either under §75.53(b) or elsewhere in this part.

(2) *Hardcopy.* The designated representative shall submit all of the hardcopy information required under §75.53 to the appropriate EPA Regional Office and the appropriate State and/or local air pollution control agency prior to initial certification. Thereafter, the designated representative shall submit hardcopy information only if that portion of the monitoring plan is revised. The designated representative shall submit the required hardcopy information as follows: no later than 21 days prior to the initial certification test; with any certification or recertification application, if a hardcopy monitoring plan change is associated with the certification or recertification event; and within 30 days of any other event with which a hardcopy monitoring plan change is associated, pursuant to §75.53(b). Electronic submittal of all monitoring plan information, including hardcopy portions, is permissible provided that a paper copy of the hardcopy portions can be furnished upon request.

(b) *Contents.* Monitoring plans shall contain the information specified in §75.53 of this part.

(c) *Format.* The designated representative shall submit each monitoring plan in a format specified by the Administrator.

(d) On and after April 27, 2011, consistent with §72.21 of this chapter, a hardcopy cover letter signed by the Designated Representative (DR) shall accompany each hardcopy monitoring plan submittal. The cover letter shall include the certification statement described in §72.21(b) of this chapter, and shall be submitted to the applicable EPA Regional Office and to the appropriate State or local air pollution control agency. For electronic monitoring plan submittals to the Administrator, a cover letter is not required. However, at his or her discretion, the DR may include important explanatory text or comments with an electronic monitoring plan submittal, so long as the information is provided in an electronic format that is compatible with the other data required to be reported under this section.

§75.63 Initial certification or recertification application.

(a) *Submission.* The designated representative for an affected unit or a combustion source shall submit applications and reports as follows:

(1) *Initial certifications.*

(i) For CEM systems or excepted monitoring systems under appendix D or E to this part, within 45 days after completing all initial certification tests, submit:

(A) To the Administrator, the electronic information required by paragraph (b)(1) of this section. Except for subpart E applications for alternative monitoring systems or unless specifically requested by the Administrator, do not submit a hardcopy of the test data and results to the Administrator.

(B) To the applicable EPA Regional Office and the appropriate State and/or local air pollution control agency, the hardcopy information required by paragraph (b)(2) of this section.

(ii) For units for which the owner or operator is applying for certification approval of the optional excepted methodology under §75.19 for low mass emissions units, submit, no later than 45 days prior to commencing use of the methodology:

(A) To the Administrator, the electronic low mass emission qualification information required by §75.53(f)(5)(i) or §75.53(h)(4)(i) (as applicable) and paragraph (b)(1)(i) of this section; and

(B) To the applicable EPA Regional Office and appropriate State and/or local air pollution control agency, the hardcopy information required by §75.19(a)(2) and §75.53(f)(5)(ii) or §75.53(h)(4)(ii) (as applicable), the hardcopy results of any appendix E (of this part) tests or any CEMS data analysis used to derive a fuel-and-unit-specific default NO_X emission rate.

(2) *Recertifications and diagnostic testing.*

(i) Within 45 days after completing all recertification tests under §75.20(b), submit to the Administrator the electronic information required by paragraph (b)(1) of this section. Except for subpart E applications for alternative monitoring systems or unless specifically requested by the Administrator, do not submit a hardcopy of the test data and results to the Administrator.

(ii) Within 45 days after completing all recertification tests under §75.20(b), submit the hardcopy information required by paragraph (b)(2) of this section to the

applicable EPA Regional Office and the appropriate State and/or local air pollution control agency. The applicable EPA Regional Office or appropriate State or local air pollution control agency may waive the requirement to provide hardcopy recertification test and data results. The applicable EPA Regional Office or the appropriate State or local air pollution control agency may also discontinue the waiver and reinstate the requirement of this paragraph to provide a hardcopy report of the recertification test data and results.

(iii) Notwithstanding the requirements of paragraphs (a)(2)(i) and (a)(2)(ii) of this section, for an event for which the Administrator determines that only diagnostic tests (*see* §75.20(b)) are required rather than recertification testing, no hardcopy submittal is required; however, the results of all diagnostic test(s) shall be submitted prior to or concurrent with the electronic quarterly report required under §75.64. Notwithstanding the requirement of §75.59(e), for DAHS (missing data and formula) verifications, no hardcopy submittal is required; the owner or operator shall keep these test results on-site in a format suitable for inspection.

(b) *Contents.* Each application for initial certification or recertification shall contain the following information, as applicable:

(1) *Electronic.*

(i) A complete, up-to-date version of the electronic portion of the monitoring plan, according to §75.53(e) and (f), in the format specified in §75.62(c).

(ii) The results of the test(s) required by §75.20, including the type of test conducted, testing date, information required by §75.59, and the results of any failed tests that affect data validation.

(2) *Hardcopy.*

(i) Any changed portions of the hardcopy monitoring plan information required under §75.53(e) and (f). Electronic submittal of all monitoring plan information, including the hardcopy portions, is permissible, provided that a paper copy can be furnished upon request.

(ii) The results of the test(s) required by §75.20, including the type of test conducted, testing date, information required by §75.59(a)(9), and the results of any failed tests that affect data validation.

(iii) [Reserved]

(iv) Designated representative signature certifying the accuracy of the submission.

(c) *Format.* The electronic portion of each certification or recertification application shall be submitted in a format to be specified by the Administrator. The hardcopy test results shall be submitted in a format suitable for review and shall include the information in §75.59(a)(9).

(d) Consistent with §72.21 of this chapter, a hardcopy cover letter signed by the Designated Representative (DR) shall accompany the hardcopy portion of each certification or recertification application. The cover letter shall include the certification statement described in §72.21(b) of this chapter, and shall be submitted to

the applicable EPA Regional Office and to the appropriate State or local air pollution control agency. For the electronic portion of a certification or recertification application submitted to the Administrator, a cover letter is not required. However, at his or her discretion, the DR may include important explanatory text or comments with the electronic portion of a certification or recertification application, so long as the information is provided in an electronic format compatible with the other data required to be reported under this section.

§75.64 Quarterly reports.

(a) *Electronic submission.* The designated representative for an affected unit shall electronically report the data and information in paragraphs (a), (b), and (c) of this section to the Administrator quarterly, beginning with the data from the earlier of the calendar quarter corresponding to the date of provisional certification or the calendar quarter corresponding to the relevant deadline for initial certification in §75.4(a), (b), or (c). The initial quarterly report shall contain hourly data beginning with the hour of provisional certification or the hour corresponding to the relevant certification deadline, whichever is earlier. For an affected unit subject to §75.4(d) that is shutdown on the relevant compliance date in §75.4(a) or has been placed in long-term cold storage (as defined in §72.2 of this chapter), quarterly reports are not required…. For any provisionally-certified monitoring system, §75.20(a)(3) shall apply for initial certifications, and §75.20(b)(5) shall apply for recertifications. Each electronic report must be submitted to the Administrator within 30 days following the end of each calendar quarter. Prior to January 1, 2008, each electronic report shall include for each affected unit (or group of units using a common stack), the information provided in paragraphs (a)(1), (a)(2), and (a)(8) through (a)(15) of this section. During the time period of January 1, 2008 to January 1, 2009, each electronic report shall include, either the information provided in paragraphs (a)(1), (a)(2), and (a)(8) through (a)(15) of this section or the information provided in paragraphs (a)(3) through (a)(15) of this section. On and after January 1, 2009, the owner or operator shall meet the requirements of paragraphs (a)(3) through (a)(15) of this section only. Each electronic report shall also include the date of report generation.

(1) Facility information:

(i) Identification, including:

(A) Facility/ORISPL number;

(B) Calendar quarter and year for the data contained in the report; and

(C) Version of the electronic data reporting format used for the report.

(ii) Location, including:

(A) Plant name and facility ID;

(B) EPA AIRS facility system ID;

(C) State facility ID;

(D) Source category/type;

(E) Primary SIC code;

(F) State postal abbreviation;

(G) County code; and
(H) Latitude and longitude.

(2) The information and hourly data required in §75.53 and §§75.57 through 75.59, excluding the following:
(i) Descriptions of adjustments, corrective action, and maintenance;
(ii) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan);
(iii) Opacity data listed in or §75.57(f), and in §75.59(a)(8);
(iv) For units with SO_2 or NO_X add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in §75.58(b)(3);
(v) [Reserved]
(vi) Information required by §75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes;
(vii) Hardcopy monitoring plan information required by §75.53 and hardcopy test data and results required by §75.59;
(viii) Records of flow monitor and moisture monitoring system polynomial equations, coefficients, or "K" factors required by §75.59(a)(5)(vi) or §75.59(a)(5)(vii);
(ix) Daily fuel sampling information required by §75.58(c)(3)(i) for units using assumed values under appendix D;
(x) Information required by §§75.59(b)(1)(vi), (vii), (viii), (ix), and (xiii), and (b)(2)(iii) and (iv) concerning fuel flowmeter accuracy tests and transmitter/transducer accuracy tests;
(xi) Stratification test results required as part of the RATA supplementary records under §75.59(a)(7);
(xii) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to problems unrelated to monitor performance; and
(xiii) Supplementary RATA information required under §75.59(a)(7), except that:
(A) The applicable data elements under §75.59(a)(7)(ii)(A) through (T) and under §75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (*i.e.*, Method 2F or 2G in appendices A-1 and A-2 to part 60 of this chapter), with or without wall effects adjustments;
(B) The applicable data elements under §75.59(a)(7)(ii)(A) through (T) and under §75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;
(C) The data under §75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A-1 and A-2 to part 60 of

this chapter is used and a default wall effects adjustment factor is applied; and

(D) The data under §75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is applied.

(3) Facility identification information, including:
- (i) Facility/ORISPL number;
- (ii) Calendar quarter and year for the data contained in the report; and
- (iii) Version of the electronic data reporting format used for the report.

(4) In accordance with §75.62(a)(1), if any monitoring plan information required in §75.53 requires an update, either under §75.53(b) or elsewhere in this part, submission of the electronic monitoring plan update shall be completed prior to or concurrent with the submittal of the quarterly electronic data report for the appropriate quarter in which the update is required.

(5) The daily calibration error test and daily interference check information required in §75.59(a)(1) and (a)(2) must always be included in the electronic quarterly emissions report. All other certification, quality assurance, and quality control information in §75.59 that is not excluded from electronic reporting under paragraph (a)(2) or (a)(7) of this section shall be submitted separately, either prior to or concurrent with the submittal of the relevant electronic quarterly emissions report. However, reporting of the information in §75.59(a)(9)(x) is not required until September 26, 2011, and reporting of the information in §75.59(a)(15), (b)(6), and (d)(4) is not required until March 27, 2012.

(6) The information and hourly data required in §§75.57 through 75.59, and daily calibration error test data, daily interference check, and off-line calibration demonstration information required in §75.59(a)(1) and (2).

(7) Notwithstanding the requirements of paragraphs (a)(4) through (a)(6) of this section, the following information is excluded from electronic reporting:
- (i) Descriptions of adjustments, corrective action, and maintenance;
- (ii) Information which is incompatible with electronic reporting (e.g., field data sheets, lab analyses, quality control plan);
- (iii) Opacity data listed in §75.57(f), and in §75.59(a)(8);
- (iv) For units with SO_2 or NO_X add-on emission controls that do not elect to use the approved site-specific parametric monitoring procedures for calculation of substitute data, the information in §75.58(b)(3);
- (v) Information required by §75.57(h) concerning the causes of any missing data periods and the actions taken to cure such causes;
- (vi) Hardcopy monitoring plan information required by §75.53 and hardcopy test data and results required by §75.59;
- (vii) Records of flow monitor and moisture monitoring system polynomial equations, coefficients, or "K" factors required by §75.59(a)(5)(vi) or §75.59(a)(5)(vii);

(viii) Daily fuel sampling information required by §75.58(c)(3)(i) for units using assumed values under appendix D of this part;

(ix) Information required by §§75.59(b)(1)(vi), (vii), (viii), (ix), and (xiii), and (b)(2)(iii) and (iv) concerning fuel flowmeter accuracy tests and transmitter/transducer accuracy tests;

(x) Stratification test results required as part of the RATA supplementary records under §75.59(a)(7);

(xi) Data and results of RATAs that are aborted or invalidated due to problems with the reference method or operational problems with the unit and data and results of linearity checks that are aborted or invalidated due to problems unrelated to monitor performance;

(xii) Supplementary RATA information required under §75.59(a)(7)(i) through §75.59(a)(7)(v), except that:

(A) The applicable data elements under §75.59(a)(7)(ii)(A) through (T) and under §75.59(a)(7)(iii)(A) through (M) shall be reported for flow RATAs at circular or rectangular stacks (or ducts) in which angular compensation for yaw and/or pitch angles is used (*i.e.*, Method 2F or 2G in appendices A-1 and A-2 to part 60 of this chapter), with or without wall effects adjustments;

(B) The applicable data elements under §75.59(a)(7)(ii)(A) through (T) and under §75.59(a)(7)(iii)(A) through (M) shall be reported for any flow RATA run at a circular stack in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is determined by direct measurement;

(C) The data under §75.59(a)(7)(ii)(T) shall be reported for all flow RATAs at circular stacks in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a default wall effects adjustment factor is applied; and

(D) The data under §75.59(a)(7)(ix)(A) through (F) shall be reported for all flow RATAs at rectangular stacks or ducts in which Method 2 in appendices A-1 and A-2 to part 60 of this chapter is used and a wall effects adjustment factor is applied; and

(xiii) The certification required by section 6.1.2(b) of appendix A to this part and recorded under §75.57(a)(7).

(8) Tons (rounded to the nearest tenth) of SO_2 emitted during the quarter and cumulative SO_2 emissions for the calendar year.

(9) Average NO_X emission rate (lb/mmBtu, rounded to the nearest thousandth) during the quarter and cumulative NO_X emission rate for the calendar year.

(10) Tons of CO_2 emitted during quarter and cumulative CO_2 emissions for calendar year.

(11) Total heat input (mmBtu) for quarter and cumulative heat input for calendar year.

(12) Unit or stack or common pipe header operating hours for quarter and cumulative unit or stack or common pipe header operating hours for calendar year.

(13) For low mass emissions units for which the owner or operator is using the optional low mass emissions methodology in §75.19(c) to calculate NO_X mass emissions, the designated representative must also report tons (rounded to the nearest tenth) of NO_X emitted during the quarter and cumulative NO_X mass emissions for the calendar year.

(14) For low mass emissions units using the optional long term fuel flow methodology under §75.19(c), for each quarter report the long term fuel flow for each fuel according to §75.58(f)(2).

(15) For units using the optional fuel flow to load procedure in section 2.1.7 of appendix D to this part, report both the fuel flow-to-load baseline data and the results of the fuel flow-to-load test each quarter.

(b) The designated representative shall affirm that the component/system identification codes and formulas in the quarterly electronic reports, submitted to the Administrator pursuant to §75.53, represent current operating conditions.

(c) *Compliance certification.* The designated representative shall submit a certification in support of each quarterly emissions monitoring report based on reasonable inquiry of those persons with primary responsibility for ensuring that all of the unit's emissions are correctly and fully monitored. The certification shall indicate whether the monitoring data submitted were recorded in accordance with the applicable requirements of this part including the quality control and quality assurance procedures and specifications of this part and its appendices, and any such requirements, procedures and specifications of an applicable excepted or approved alternative monitoring method. For a unit with add-on emission controls, the designated representative shall also include a certification, for all hours where data are substituted following the provisions of §75.34(a)(1), that the add-on emission controls were operating within the range of parameters listed in the monitoring plan and that the substitute values recorded during the quarter do not systematically underestimate SO_2 or NO_X emissions, pursuant to §75.34.

(d) *Electronic format.* Each quarterly report shall be submitted in a format to be specified by the Administrator, including both electronic submission of data and (unless otherwise approved by the Administrator) electronic submission of compliance certifications.

(e) [Reserved]

(f) *Method of submission.* Beginning with the quarterly report for the first quarter of the year 2001, all quarterly reports shall be submitted to EPA by direct computer-to-computer electronic transfer via EPA-provided software, unless otherwise approved by the Administrator.

(g) At his or her discretion, the DR may include important explanatory text or comments with an electronic quarterly report submittal, so long as the information is provided in a format that is compatible with the other data required to be reported under this section.

Analysis: Condition H23.3 will be added to require the turbines to comply with the applicable requirements of 40 CFR Part 75.

Subpart H—NO_X Mass Emissions Provisions

§75.70 NO_X Mass Emissions Provisions

(a) *Applicability*. The owner or operator of a unit shall comply with the requirements of this subpart to the extent that compliance is required by an applicable State or federal NO_X mass emission reduction program that incorporates by reference, or otherwise adopts the provisions of, this subpart.

Analysis: The SCAQMD is not subject to any State or federal NOx mass emission reduction that requires Part 75 monitoring. An example of a program that requires Part 75 monitoring is the Regional Greenhouse Gas Initiative (RGGI). The RGGI was the nation's first mandatory cap-and-trade program for greenhouse gas (GHG) emissions and involves nine states—Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

PART 76—ACID RAIN NITROGEN OXIDES EMISSION REDUCTION PROGRAM

§76.1 Applicability

(a) Except as provided in paragraphs (b) through (d) of this section, the provisions apply to each coal-fired utility unit that is subject to an Acid Rain emissions limitation or reduction requirement for SO_2 under Phase I or Phase II pursuant to sections 404, 405, or 409 of the Act.

Analysis: As Part 76 is applicable to coal-fired utility units only, this part not applicable to the gas-fired turbines under evaluation. This Part provides NOx emission limitations for §76.5 Group 1 boilers, §76.6 Group 2 boilers, and §76.7 Group 1, Phase II boilers.

PART 77—EXCESS EMISSIONS

PART 78—APPEAL PROCEDURES

Parts 77 and 78 are not related to permitting requirements.

STATE REGULATIONS

California Environmental Quality Act (CEQA)

CEQA applies to projects undertaken by a public agency, funded by a public agency, or requires an issuance of a permit by a public agency. A "project" means the whole of an action that has a potential for resulting in physical change to the environment, and is an activity that may be subject to discretionary approvals by government agencies. A project is exempt from CEQA if by statute, if considered ministerial or categorical, or where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment.

The turbine upgrade project is subject to CEQA because there are no applicable exemptions. The California Energy Commission (CEC) is the lead agency for licensing thermal power plants 50

megawatts and larger under the California Environmental Quality Act (CEQA) and has a certified regulatory program under CEQA. Under its certified program, the CEC is exempt from having to prepare an environmental impact report. The CEC certified the License for the MGS on 5/23/03. The MGS was constructed and began commercial operations in October of 2005.

On 11/21/17, Bicent filed the *Petition to Amend the Final Decision for the Malburg Generating Station* (01-AFC-25C) with the CEC to modify the existing MGS Final Decision. The Petition requested approval for the installation of the Siemens SGT-800 A-Plus Turbine Upgrade package ("A+ Turbine Upgrade") on the two turbines to increase power output, as well as requested revisions to existing Conditions of Certification AQ-C7 and AQ-C8.

On 2/4/19, Bicent filed the *Petition to Amend for Site Delineation* to further amend the CEC Decision for the MGS. On April 10, 2008, Bicent acquired the MGS from the City of Vernon and filed a petition for change of ownership, which was approved by the CEC in May 2008. The Petition requested modification of the site boundary to reflect that Bicent does not control certain portions within the current site boundary and ancillary facilities, which are still owned and operated by the City of Vernon. These areas include the natural gas pipeline, the landscaping area outside the boundary of the MGS, and Station A, a designated historical resource. Based on the proposed site delineation, the Petition also requested deletion of Conditions of Certification HAZ-6, HAZ-7, VIS-2, VIS-3, and CUL-8.

The purpose of the CEC's amendment review process is to assess the impacts of the proposal on environmental quality and on public health and safety. The review process includes an evaluation of the consistency of the proposed changes with the CEC's Decision and a determination whether the facility, as modified, would remain in compliance with applicable laws, ordinances, regulations, and standards. After the staff has completed its independent review and analysis of this petition, it will publish its assessment for public review and comment for 30 days. Upon completion of its review, staff will schedule the amendment for consideration by the Energy Commission at a regularly scheduled Business Meeting.

California Code of Regulations (CCR), Title 20, Chapter 11—Greenhouse Gases Emission Performance Standard, Article 1—Provisions Applicable to Powerplants 10 MW and Larger (SB 1368)

The California Emissions Performance Standard (EPS) of 1100 lbs CO_2/MW-hour-net of electricity applies to local publicly owned electric utilities. California regulations stipulate that no local publicly owned electric utility shall enter into a covered procurement if greenhouse gases emissions from the power plant(s) subject to the covered procurement exceed the EPS. A "covered procurement" is defined in §2901(d) as "(1) A new ownership investment in a base load generation power plant, or (2) A new or renewed contract commitment, including a lease, for the procurement of electricity with a term of five years or greater by a local publicly owned electric utility with: (A) a base load generation power plant, unless the power plant is deemed compliant, or (B) any generating units added to a

deemed-compliant base load generation power plant that combined result in an increase of 50 MW or more to the power plant's rated capacity."

The local publicly owned electric utility from which Bicent secures a covered procurement is required to submit a compliance filing to the California Energy Commission. The Commission then issues a decision on whether the covered procurement complies with the EPS.

§ 2900. Scope.

This Article applies to covered procurements entered into by local publicly owned electric utilities. The greenhouse gases emission performance standard established in section 2902(a) applies to any generation, regardless of capacity, supplied under a covered procurement. The provisions requiring local publicly owned electric utilities to report covered procurements, including Sections 2908, 2909, and 2910, apply only to covered procurements involving powerplants 10 MW and larger.

Analysis:

Because §2900 provides that local publicly owned electric facilities shall make a determination regarding compliance with the EPS prior into entering into a covered procurement, SCAQMD need not make a determination.

RECOMMENDATION

Based on the above analysis, it is recommended that the Permits to Construct be issued following the conclusion of the required EPA review period, and public review and comment periods, subject to any comments received during these periods.

APPENDIX—ENGINEERING & PERMITTING (E&P) MODELING REVIEW MEMO, DATED 3/22/19

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT
ENGINEERING & PERMITTING
MEMORANDUM

TO:	Bhaskar Chandan
FROM:	Sam Wang
DATE:	March 22, 2019
BUSINESS NAME:	Bicent (California) Malburg, LLC (Malburg Generating Station, MGS)
APPLICATION NUMBER:	598922-598923
FACILITY NUMBER:	155474

SUBJECT: Review of Modeling Files, Bicent (California) Malburg, LLC (ID 155474), 4963 S. Soto St, Vernon, CA 90058, Appl. Nos. 598922-598923, Modeling Review Request Memo, Rev. 1, [1/25/2019]

The SCAQMD Engineering & Permitting modeling staff completed the review of the dispersion modeling analysis and Health Risk Assessment (HRA) conducted for the proposed MGS power plant - Turbine Upgrade Project, located at 4963 S. Soto St, Vernon, CA 90058.

Bicent (California) Malburg LLC ("Bicent") (ID 155474) is the operator of the Malburg Generating Station ("MGS"), which generates electric power for sale to the City of Vernon. The facility was constructed by the Vernon City, Light & Power Dept (now re-named the Vernon Public Utilities) (ID 14502), then sold to Bicent in 2008. Malburg consists of (1) two Alstom (redesignated to Siemens) combined-cycle, natural gas fueled combustion turbines with associated generators, duct burners and heat recovery steam generators (HRSGs), and a common steam turbine generator; (2) two associated CO oxidation catalyst and selective catalytic reduction (SCR) systems; (3) an aqueous ammonia tank; (4) an emergency engine for the fire pump; (5) an oil water separator; and (6) a cooling tower. The emergency engine is exempt from modeling requirements per Rule 1304(a)(4) and health risk assessment requirements per Rule 1401(g)(1)(F), and the cooling tower is exempt from permitting per Rule 219(d)(3).

After reviewing all the modeling files submitted by Bicent, SCAQMD staff found several modeling issues which are summarized as follows:

- Inadequate meteorological data and selection of the most representative meteorological station
- Outdated and incorrect background air quality monitoring data and selection of the most representative air quality monitoring stations
- some model results do not include the impacts for individual sources

- some near field receptors have incorrect elevations and no receptors on the southern portion of the project site[2] (files dated 11/27/2018)

Therefore, due to time constraints, SCAQMD Modeling staff re-ran the AERMOD and HRA using the correct settings. The major differences between the applicant's modeling files with SCAQMD's modeling files are summarized in the Table below. The detailed description to explain the differences are provided in Attachment A of this memo.

Major Differences Between Applicant's Modeling Files With SCAQMD's Modeling Files

	Applicant	SCAQMD
Meteorological Data and Station	3 years (2012, 2015, and 2016) meteorological data from SCAQMD's Compton Station were used. Compton Station is located 6 mile south of the project site.	5 years (2012, 2013, 2014, 2015, and 2016) meteorological data from SCAQMD's Downtown LA/USC Station were used. Downtown LA/USC Station is located 4 mile north-northwest of the project site and has been determined to be the most representative meteorological station to use for this project analyses.
Ozone Data and Station	3 years (2012, 2015, and 2016) ozone data from SCAQMD's Compton Station were used.	5 years (2012, 2013, 2014, 2015, and 2016) ozone data from SCAQMD's Compton Station were used.
Background Air Quality Monitoring Data	3 years (2014, 2015, and 2016) background air quality monitoring data were obtained from Compton, LA-N. Main Street, and Pico Rivera #2 stations from SCAQMD and EPA AIRS database.	The most recent 3 years (2015, 2016, and 2017) background air quality monitoring data were obtained from Compton and LA-N. Main Street stations from SCAQMD monitoring data. Pico Rivera #2 station is downwind to the project site and has different wind patterns than the project site. Therefore this station should be excluded. SCAQMD's monitoring data is more reliable and should be used in the analysis.
Receptors	The original modeling files have near field receptors (20 meter spacing) with fenceline grids and far field receptors (100 meter spacing). The 2019 revised modeling files have only 58 additional receptors placed on the southern side of the project site due to the fenceline change (Petition to Amend for Site Delineation, CEC, 2/4/2019).	All modeling files include fenceline grids, near and far field receptors using the new site layout boundary due to the fenceline change (including about 100 additional receptors on the south side of project). The heights were adjusted for the near field receptors placed on the top of buildings.

2 On 2/27/2109, SCAQMD required MGS to re-submit the modeling (both criteria pollutants and HRA) files for review due to the property boundary (fenceline) change recently. This change is based on the information in "Malburg Generating Station Petition to Amend For Site Delineation" that MGS submitted to CEC on 2/4/2019 (TN#22640).

Screening model	Screening modeling for the turbine was performed.	Screening modeling for the turbine was re-run based on the new model settings (meteorological data, ozone data, receptors, and etc.). The results show Scenario 14 has the worst impacts for all pollutants in all averaging time.
Operation (normal, startup, commissioning)	AERMOD modeling was performed. The model results have the total impacts from the entire facility as well as the total impacts from the two turbines combined.	AERMOD modeling was re-run using the new model settings and the parameters from new screening results. In addition to the total impacts from the entire facility and total impacts from the two turbines combined, the model results also provide the impacts from each turbine and each stationary source.
Fumigation	AERSCREEN modeling was performed.	Modeling is acceptable - no comment on the applicant's files
HRA	Tier 4 HRA was performed.	Tier 4 HRA was re-run using the new model settings and the parameters from new screening results.

SCAQMD's detailed comments and modeling results can also be found in the Attachment A of this memo. The SCAQMD's modeling results for Air Quality (AQ) and HRA impacts from the entire project are all under the applicable thresholds in Rule 1303, Rule 1401, and Rule 2005 for all criteria pollutants and air toxics. Therefore, the AQ impacts from the MGS are considered in compliance with National Ambient Air Quality Standards (NAAQS), California Ambient Air Quality Standards (CAAQS), and SCAQMD's modeling and HRA requirements.

SCAQMD modeling staff's detailed modeling compliance check and comments on the AQ dispersion modeling analysis and HRA are in the Attachment A in this memo. If there's any question please contact the modeling reviewer, Sam Wang at ext. 2649.

cc: Vicky Lee and Rizaldy Calungcagin

Attachment A
Modeling Review Check Form

Project Information				
Application #	598922-598923	**BUSINESS NAME**	Malburg Generating Station (MGS)	
Facility ID	155474	**Application Type**	P/C and P/O	
Date	3/19/2019	**Reviewer**	Sam Wang	

Modeling Review Result Summary					
	Not applicable	**Yes**	**Yes with additional conditions**	**No**	**Requirement in Rules and Regulations**
1.	☐	☒	☐	☐	Rule 1303 NSR
2.	☐	☒	☐	☐	Rule 1401/1402 NSR for TAC
3.	☒	☐	☐	☐	Rule 1703 PSD Analysis
4.	☐	☒	☐	☐	Rule 2005 NSR for RECLAIM
5.	☒	☐	☐	☐	Other:_____

Applicant's Modeling Analysis Review – Item Check (Explain if "No" is checked)	
6.	☒**Yes** ☐ **No, Was the appropriate air quality model selected to perform the analysis?**
	AERSCREEN, version __16216___ AERMET, version _____ AERMOD[3], version ___18081__ BPIP-Prime, version __04274__ AERMAP, version ___18081_____ HARP-ADMRT, version __ 19044_____ HARP-RAST, version _____ Other Models: _____, version _____ Explain:
7.	☐ **Yes** ☒ **No, Were the most representative ambient AQ background monitoring data obtained and used in the analysis?**
	Monitoring station: ___Compton station (SCAQMD station: South Central LA County, #112)_ Distance and direction to project: ____6 mile, South to Project Site Years: ____2014, 2015, 2016_____

[3] SCAQMD Modeling Guidance for AERMOD is on the website at: http://www.aqmd.gov/home/air-quality/air-quality-data-studies/meteorological-data/modeling-guidance

Explain:
3 years (2014, 2015, and 2016) background air quality monitoring data were obtained from Compton, LA-N. Main Street, and Pico Rivera #2 station from SCAQMD and EPA AIRS database in applicant's analysis. However, Pico Rivera #2 station is downwind to the project site and have different wind patterns than the project site. Therefore this station should be excluded. SCAQMD's monitoring data is more reliable and should be used in the analysis. Central LA station is about 4 miles NNW of the project site. Central LA station is closer and more upwind to the project site than Compton station. Therefore, the most recent 3 years (2015-2017) background air quality monitoring data should be obtained from Central LA station (SCAQMD station: Central LA, #087) and Compton station (SCAQMD station: South Central LA County, #112). Please see detailed comments and SCAQMD's analysis below.

8. ☐ **Yes** ☐ **No** ☒ **Not applicable, Was Class I Area identified to the project?**

Class I area: _____
Distance and direction to project: _____

Note:

9. ☒ **Yes** ☐ **No, Did the model correctly include the project layout?** (Including but not limited to: surrounding topographic features, terrain options and terrain process, project site boundary, locations of sources, structures, and buildings, building downwash, domain area, coordinates, and etc.)

Explain:
Terrain file (NEDU_26550036.TIF) is the correct file to use for this project's location and domain. The revised modeling files from the applicant submitted on 3/8/2019 provided a correct project layout.

10. ☐ **Yes** ☒ **No, Did the model control pathway have correct input?** (Including but not limited to: regulatory and model options, pollutants, averaging time, NAAQS and CAAQS selections, rural/urban, deposition/depletion, NOx to NO2 conversion options, and etc.)

Explain:
Some pollutant and averaging time selections in the model control pathway are off. For example, the California standards should be the highest of multi-year runs but they were selected as the average of multi-year runs in applicants' modeling files. In addition, some model results do not include the impacts for individual sources. They were fixed in the SCAQMD staff's revised modeling files.

11. ☐ **Yes** ☒ **No, Were the most representative meteorological data[4] used in the analysis?**

Meteorological station: SCAQMD's Compton Station
Distance and direction to project: 6 miles, S
Years: 2012, 2015, 2016

[4] It is required that the applicant use the most recent version of meteorological data that is either processed by or approved by SCAQMD and from the most appropriate meteorological station for the proposed project.

	Explain: 5 year of meteorological data is required to use in the modeling per EPA's Appendix W[5] and SCAQMD's requirements[6]. The project used only 3 year meteorological data (2012, 2015, and 2016) from SCAQMD's Compton Station, because only 3-years of data is available for this station. The Compton data have been removed from SCAQMD's website and are no longer available to download from SCAQMD's website since 2017. Instead, SCAQMD's Downtown LA/USC station should be the most representative meteorological station to use for this project analyses. Please see the detailed comments below.
12.	☐ **Yes** ☒ **No, Were the source data correct in the analysis?** [Including but not limited to: source type selections, source parameters (emission rate, temperature, exit velocity, release height and stack diameter, release type, operation scenarios, source group, variable emissions, in-stack ratios), and etc.]
	Explain: In addition to setting up a source group for all sources in the model, each individual source should be also a source group in the model in order to see the AQ impact from each individual source. In most normal operation runs in the applicant's modeling files, the air quality impacts per permit unit (each individual station source) were not provided.
13.	☐ **Yes** ☒ **No, Were the receptors appropriately set up in the analysis?** (Including but not limited to: dense enough receptor grid(s) with corresponding coordinates), receptor spacing, fenceline receptors, sensitive receptor and etc.)
	Nearest school, distance and direction to project: _Pacific Boulevard School, 2866 feet, South_ Other sensitive receptors: __residences_____ Explain: Please see the detailed comments below.
14.	☐ **Yes** ☒ **No, Did the project follow SCAQMD's health risk assessment procedure and have correct parameters? (**Including but not limited to: all the procedure, assumptions, and default parameters listed in SCAQMD HRA guidance. The SCAQMD's HRA procedures[7] require Hot Spots Analysis and Reporting Program (HARP) to be used in Tier 4 risk assessments for this Project for Rule 1401 compliance. **)**

5 EPA Appendix W, 2017 (https://www3.epa.gov/ttn/scram/appendix_w/2016/AppendixW_2017.pdf). "(page 5223) The model user should acquire enough meteorological data to ensure that worst-case meteorological conditions are adequately represented in the model results. The use of 5 years of adequately representative NWS or comparable meteorological data, at least 1 year of site-specific, or at least 3 years of prognostic meteorological data, are required."

6 It is SCAQMD's policy that requires all proposed projects to use five years of meteorological data from the most representative meteorological station to model their air quality impacts (criteria pollutants and TACs). SCAQMD modeling guidance (http://www.aqmd.gov/home/air-quality/air-quality-data-studies/meteorological-data/modeling-guidance), "*… Modeling for criteria pollutants and HRA's should use the most recently available and meteorologically-appropriate 5-year data set, as is required for AERMOD applications by U.S. EPA's Appendix W*".

7 SCAQMD Risk Assessment Procedure for Rule 1401, 1401.1 and 212, Version 8.1, September 1, 2017, http://www.aqmd.gov/docs/default-source/permitting/rule-1401-risk-assessment/riskassessproc-v8-1.pdf

	Explain: Please see detailed comments below.
15.	☒ **Yes** ☐ **No, Are all data in the permit application package consistent?** (Including but not limited to: proposed conditions in permit application, reports, vendor guarantee data, manufacture data, emission estimation sources, calculations and spreadsheets, actual modeling I/O files, and etc.)
	Explain:
16.	☒ **Yes** ☐ **No, Were all the model output files provided by the applicant?** (Including but not limited to: output settings, model processing completeness, post processing, I/O files verified, and etc.)
	Explain:

Detailed Comments

#7 Comment:
Ambient AQ Background Monitoring Data

SCAQMD staff reviewed and examined the AQ background concentrations from different monitoring stations near the project site. The background air quality monitoring data in 2015-2017 from the two SCAQMD's monitoring stations that are nearest (4 and 6 miles) to the MGS site are summarized in the Table 1 below.

Table 1
SCAQMD Background Air Quality Monitoring Data – Federal and State Design Values (concentrations are in units of ppb for NO_2, SO_2, and CO)

Monitoring Station[8]	2015	2016	2017	Design Value	ug/m^3
Federal 1-Hour NO_2 Standard 98th Percentile					
#1: Central LA station	62.4	61.0	61.7	61.7	**116.0**
#2: Compton station (South Central LA County)	58.7	58.4	66.8	61.3	115.2
State 1-Hour NO_2					
#1: Central LA station	79.1	64.7	80.6	80.6	151.5

8 Ref. https://www.arb.ca.gov/adam/topfour/topfour1.php and https://www.aqmd.gov/home/air-quality/air-quality-data-studies/historical-data-by-year
and http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-monitoring-network-plan/aaqmnp-appendix-a6BF4F040D8A9.pdf
#1: Central LA station (SCAQMD station: Central LA, #087) is located at 1630 N Main St, Los Angeles, 4 miles NNW from the project, 34.066399:-118.2267
#2: Compton station (SCAQMD station: South Central LA County, #112) is located at 700 North Bullis Road, Compton, 6 miles S from the project, 33.90139:-118.205002

#2: Compton station (South Central LA County)	73.6	63.7	99.1	99.1	**186.3**
Federal Annual NO_2					
#1: Central LA station	22.2	20.8	20.5	21.2	**39.8**
#2: Compton station (South Central LA County)	16.9	15.6	16.1	16.2	30.5
State Annual NO_2					
#1: Central LA station	22.2	20.8	20.5	22.2	**41.7**
#2: Compton station (South Central LA County)	16.9	15.6	16.1	16.9	31.8
Federal and State 24 hour PM_{10}					
#1: Central LA station	88	67	96	96	**96**
#2: Compton station (South Central LA County)	NA	NA	NA	NA	NA
State Annual PM_{10}					
#1: Central LA station	33	32.4	34.4	34.4	**34.4**
#2: Compton station (South Central LA County)	NA	NA	NA	NA	NA
Federal 24 hour $PM_{2.5}$					
#1: Central LA station	38.0	27.3	27.8	31.0	31.0
#2: Compton station (South Central LA County)	27.6	26.35	41.3	31.8	**31.8**
Federal Annual $PM_{2.5}$					
#1: Central LA station	12.38	11.83	11.94	12.1	**12.1**
#2: Compton station (South Central LA County)	11.78	11.13	12.92	11.9	11.9
State Annual $PM_{2.5}$					
#1: Central LA station	12.38	11.83	11.94	12.38	12.38
#2: Compton station (South Central LA County)	11.78	11.13	12.92	12.92	**12.92**
Federal and State 1 hour CO					
#1: Central LA station	3.2	1.9	1.9	3.2	3648.0
#2: Compton station (South Central LA County)	4.4	4.4	6.1	6.1	**6954.0**
Federal and State 8 hour CO					
#1: Central LA station	1.8	1.4	1.6	1.8	2052.0
#2: Compton station (South Central LA County)	3.3	3.9	4.6	4.6	**5244.0**
Federal 1 hour SO_2					
#1: Central LA station	6.3	2.5	2.6	3.8	**9.9**

#2: Compton station (South Central LA County)	NA	NA	NA	NA	NA
State 1 hour SO_2					
#1: Central LA station	12.6	13.4	5.7	13.4	**34.97**
#2: Compton station (South Central LA County)	NA	NA	NA	NA	NA
Federal 3 hour SO_2[a]					35.1
State 24 hour SO_2					3.7

[a] Federal 3-hour SO2 is based on National Secondary Standards: The levels of air quality necessary to protect the public welfare from any known or anticipated adverse effects of a pollutant. All the other federal standards are based on National Primary Standards: The levels of air quality necessary, with an adequate margin of safety to protect the public health.

From the data presented in Table 1, the background air quality monitoring values in 2015-2017 from Central LA station are higher than those values in Compton stations for many pollutants and averaging time. Central LA station is closer and more upwind to the proposed project site. After consulting with Rene Bermudez, Atmospheric Measurements Manager and other staff in STA in SCAQMD, it was determined those higher values from SCAQMD's Central LA stations are more representative and should be used for this project

#11 Comment
Meteorological Data

SCAQMD's Downtown LA/USC Station is located 4 mile north-northwest of the project site and has similar wind patterns and surface characteristics and therefore this meteorological station has been determined to be the most representative meteorological station to use for this project analyses. Five year of meteorological data is required to use in the modeling per EPA's Appendix W and SCAQMD's requirements. Therefore, 5 years (2012, 2013, 2014, 2015, and 2016) meteorological data from SCAQMD's Downtown LA/USC Station were used in SCAQMD modeling analysis.

#13 Comment
Receptors

The original applicant's modeling files have near field receptors (20 meter spacing) with fenceline grids and far field receptors (100 meter spacing). However, the original applicant's modeling files did not have the receptors on the southern project site which is not controlled by MGS. The 2019 applicant's revised modeling files have only 58 additional receptors placed on the southern side of the project site due to the fenceline change (Petition to Amend for Site Delineation, CEC, 2/4/2019). The revised modeling files by the SCAQMD include fenceline grids, near and far field receptors using the new site layout boundary due to the fenceline change. In addition, the

elevations/heights were adjusted for some near field receptors placed on the top of buildings in the SCAQMD staff's revised modeling files.

SCAQMD's AIR QUALITY IMPACTS ANALYSES AND RESULTS

Therefore, SCAQMD staff fixed all the modeling issues described above (meteorological data, ozone data, receptors, control pathways, source groups, and etc.), used the correct background air quality monitoring data, and re-ran AERMOD for all operation scenarios. The air quality impact assessment and modeling results are summarized in Table 2 to Table 6 below.

NORMAL OPERATIONS IMPACT ANALYSIS

Table 2
Modeled Stack Parameters – Normal Operations Impact Analysis

Pollutants	Averaging Period	Stack Diameter (m)	Stack Height (m)	Exhaust Temp (°K)	Exhaust velocity (m/s)	Case
Normal Operating Conditions Analysis						
Turbine						
NO_2, CO, SO_2	1-hour	3.6576	33.53	377.59	13.844	S14
SO_2	3-hour	3.6576	33.53	377.59	13.844	S14
CO	8-hour	3.6576	33.53	377.59	13.844	S14
SO_2, $PM_{10}/PM_{2.5}$	24-hour	3.6576	33.53	377.59	13.844	S14
NO_2, SO_2, $PM_{10}/PM_{2.5}$	Annual	3.6576	33.53	377.59	13.844	S14
Fire pump						
All	All	0.1143	3.51	738.15	69.458	--
Cooling tower (each cell, 3 cells total)						
$PM_{10}/PM_{2.5}$	24-hour, Annual	6.7056	13.73	316.00	10.028	--
Start-up and Shutdown Analysis						
Turbine						
NO_2, CO	1-hour	3.6576	33.53	375.37	9.556	S1
	1-hour	3.6576	33.53	377.59	13.844	S14 [a, b]

CO	8-hour	3.6576	33.53	375.37	9.556	S1
Fire pump						
CO	8-hour	0.1143	3.51	738.15	69.458	--

[a] The Application based the modeling on the operation of one turbine. As requested by the SCAQMD, the modeling was revised to include the simultaneous operation of the second turbine.

[b] For Scenario One—One Turbine in Cold Start-up, Second Turbine in Max Baseload (CO): Second turbine is in continuous operation at 100% load at 59 °F ambient temperature (Case S14).

Table 3
Modeled Results -Normal Operations Impact Analysis – Total Facility

Attainment Pollutant	**Averaging Period**	**Maximum Modeled Concentration (µg/m³)**	**Background Concentration (µg/m³)**	**Total Concentration (µg/m³)**	**State Standard, CAAQS[c] (µg/m³)**	**Federal Standard, NAAQS[c] (µg/m³)**	**Exceeds Any Threshold?**
Normal Operating Conditions Analysis							
NO_2 [a]	1-hour	80.54	186.3	266.8	339	--	No
	1-hour (98th percentile)	3.78	116.0	119.78	--	188	No
	Annual (Federal)	0.478	39.8	40.28	--	100	No
	Annual Maximum (State)	0.507	41.7	42.21	57	--	No
SO_2	1-hour	0.16	34.97	35.13	655	--	No
	1-hour (99th percentile)	0.16	9.9	10.06	--	196	No
	3-hour	0.12	35.1	35.22	--	1,300	No
	24-hour	0.05	3.7	3.75	105	--	No
CO	1-hour	9.01	6,954	6,963	23,000	40,000	No
	8-hour	1.23	5,244	5,245	10,000	10,000	No
PM_{10}	24-hour	0.84	96	96.8	--	150	No
Non-Attainment Pollutant[b]	**Averaging Period**	**Maximum Modeled Concentration (µg/m³)**	**State Standard CAAQS (µg/m³)**	**Federal Standard, NAAQS (µg/m³)**	**Rule 1303 Thresholds (µg/m³)**		**Exceeds Any Threshold?**
PM_{10}	24-hour	1.07	50	51.07	2.5		No
	Annual Maximum	0.35	20		1		No
$PM_{2.5}$	24-hour (98th percentile)	0.77	31.8	35	2.5		No

	Annual Maximum	0.347	12		1	No

Startup and Shutdown Analysis

Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m^3)	Background Concentration (µg/m^3)	Total Concentration (µg/m^3)	State Standard CAAQS (µg/m^3)	Federal Standard, NAAQS (µg/m^3)	Exceeds Any Threshold?
Scenario One—One Turbine in Cold Start-up, **Second Turbine in Cold Start-up (NOx) or Max Baseload (CO),** Fire Pump Not in Operation							
NO_2 [a]	1-hour	78.11	186.3	264.4	339	--	No
	1-hour (98th percentile)	57.31	116.0	173.3	--	188	No
CO	1-hour	131.21	6,954	7,085	23,000	40,000	No
Scenario Two--Two Turbines in Non-Cold (Warm or Hot) Start-up, Fire Pump Not in Operation							
NO_2 [a]	1-hour	65.12	186.3	251.4	339	--	No
	1-hour (98th percentile)	47.85	116.0	163.9	--	188	No
CO	1-hour	76.04	6,954	7,030	23,000	40,000	No
Two Turbines Complete Cold Start, Non-Cold Start, Shutdown and Balance at Normal Operation, Fire Pump Operate 1 hr							
CO	8-hour	31.31	5,244	5,275	10,000	10,000	No

a 1-hr NO_2 impacts for comparison to CAAQS under Normal Operating Conditions with the Ozone Limiting Method (OLM). All other NO_2 1-hour and annual impacts evaluated assuming 100% conversion of NOx to NO2.

b Effective July 26, 2013, the South Coast Air Basin has been re-designated to attainment for the federal 24-hour PM10 AAQS. The South Coast Air Basin is designated non-attainment for the state PM10 standards, and state and federal PM2.5 standards; therefore, project increments are compared to the significant change thresholds in Rule 1303.

c Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted. On April 12, 2010, the U.S. EPA established a new 1-hour NO2 standard of 100 ppb (188 µg/m3). The form of the federal 1-hour NO2 standard involves a three year average of the 98th percentile of the annual distribution of daily maximum 1-hour concentrations. Based on the U.S. EPA's memo dated March 1, 2011, commissioning is a once in a lifetime event and therefore, can be excluded from compliance with the federal 1-hour NO2 standard. On June 2, 2010, the U.S. EPA established a new 1-hour SO2 standard of 75 ppb (196 µg/m3). The form of the federal 1-hour SO2 standard involves a three year average of the 99th percentile of the annual distribution of daily maximum 1-hour concentrations. On December 14, 2012, the national annual PM2.5 primary standard was lowered from 15 µg/m3 to 12.0 µg/m3. The existing national 24- hour PM2.5 standards (primary and secondary) were retained at 35 µg/m3 (98th percentile, averaged over 3 years), as was the annual secondary standard of 15 µg/m3. The existing 24-hour PM10 standards (primary and secondary) of 150 µg/m3 also were retained. The form of the annual primary and secondary standards is the annual mean, averaged over 3 years.

SCAQMD staff also modelled the AQ impacts by each individual sources (per permit unit) and compared the modeling results to the applicable thresholds for all criteria pollutants with different

averaging time. Table 4 and Table 5 below present the AQ impacts by each turbine. The air quality impacts from each turbine do not exceed any NAAQS/CAAQS and any applicable thresholds in Table A-2 in Rule 1303 and Table A-2 in Rule 2005.

Table 4
Modeled Results -Normal Operations Impact Analysis – Turbine 1

Attainment Pollutant	**Averaging Period**	**Maximum Modeled Concentration (µg/m^3)**	**Background Concentration (µg/m^3)**	**Total Concentration (µg/m^3)**	**State Standard, CAAQS[c] (µg/m^3)**	**Federal Standard, NAAQS[c] (µg/m^3)**	**Exceeds Any Threshold?**
Normal Operating Conditions Analysis							
NO_2 [a]	1-hour	1.87	186.3	188.17	339	--	No
	1-hour (98th percentile)	1.81	116.0	117.81	--	188	No
	Annual (Federal)	0.22	39.8	40.02	--	100	No
	Annual Maximum (State)	0.23	41.7	41.93	57	--	No
SO_2	1-hour	0.08	34.97	35.05	655	--	No
	1-hour (99th percentile)	0.08	9.9	9.98	--	196	No
	3-hour	0.06	35.1	35.16	--	1,300	No
	24-hour	0.02	3.7	3.72	105	--	No
CO	1-hour	1.26	6,954	6,955	23,000	40,000	No
	8-hour	0.59	5,244	5,245	10,000	10,000	No
PM_{10}	24-hour	0.40	96	96.4	--	150	No
Non-Attainment Pollutant[b]	**Averaging Period**	**Maximum Modeled Concentration (µg/m^3)**	**State Standard CAAQS (µg/m^3)**	**Federal Standard, NAAQS (µg/m^3)**	**Rule 1303 Thresholds (µg/m^3)**		**Exceeds Any Threshold?**
PM_{10}	24-hour	0.51	50	50.84	2.5		No
	Annual Maximum	0.16	20		1		No
$PM_{2.5}$	24-hour (98th percentile)	0.37	31.8	35	2.5		No
	Annual Maximum	0.16	12		1		No

Table 5
Modeled Results -Normal Operations Impact Analysis – Turbine 2

Attainment Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m^3)	Background Concentration (µg/m^3)	Total Concentration (µg/m^3)	State Standard, CAAQS[c] (µg/m^3)	Federal Standard, NAAQS[c] (µg/m^3)	Exceeds Any Threshold?
Normal Operating Conditions Analysis							
NO_2 [a]	1-hour	1.87	186.3	188.17	339	--	No
	1-hour (98th percentile)	1.81	116.0	117.81	--	188	No
	Annual (Federal)	0.22	39.8	40.02	--	100	No
	Annual Maximum (State)	0.23	41.7	41.93	57	--	No
SO_2	1-hour	0.08	34.97	35.05	655	--	No
	1-hour (99th percentile)	0.08	9.9	9.98	--	196	No
	3-hour	0.06	35.1	35.16	--	1,300	No
	24-hour	0.02	3.7	3.72	105	--	No
CO	1-hour	1.26	6,954	6,955	23,000	40,000	No
	8-hour	0.59	5,244	5,245	10,000	10,000	No
PM_{10}	24-hour	0.40	96	96.4	--	150	No
Non-Attainment Pollutant[b]	**Averaging Period**	**Maximum Modeled Concentration (µg/m^3)**	**State Standard CAAQS (µg/m^3)**	**Federal Standard, NAAQS (µg/m^3)**	**Rule 1303 Thresholds (µg/m^3)**		**Exceeds Any Threshold?**
PM_{10}	24-hour	0.51	50	50.84	2.5		No
	Annual Maximum	0.16	20		1		No
$PM_{2.5}$	24-hour (98th percentile)	0.37	31.8	35	2.5		No
	Annual Maximum	0.16	12		1		No

COMMISSIONING IMPACTS ANALYSES

Table 6
Modeled Results – Commissioning for One Turbine [a,b]

Pollutant	Averaging Period	Maximum Predicted Impact ($\mu g/m^3$)	Background Concentration ($\mu g/m^3$)	Total Predicted Concentration ($\mu g/m^3$)	State Standard CAAQS ($\mu g/m^3$)	Federal Standard, Primary NAAQS ($\mu g/m^3$)	Exceeds Any Threshold?
NO_2	1-hour	129.98	186.3	316.28	339	--	No
CO	1-hour	257.86	6,954	7,212	23,000	40,000	No
	8-hour	102.20	5,244	5,346	10,000	10,000	No

a. For the maximum predicted impacts from the Application (first set of results), the 1-hr NO_2 impacts for comparison to CAAQS under Normal Operating Conditions was evaluated with the Ozone Limiting Method (OLM) for CAAQS. All other NO_2 1-hour and annual impacts evaluated assuming 100% conversion of NOx to NO_2.

b. For maximum predicted impacts from Bicent Response Letter, 5/17/18, and Bicent Response Letter, 10/20/18 (second and third set of results, respectively): 1-hour NO_2 impacts evaluated using the new ARM_2 model option with default conversion of NOx to NO_2.

FUMIGATION IMPACTS ANALYSIS

In the applicant's modeling files, AERSCREEN (version 16216) was used for the inversion-breakup fumigation impacts. The worst case short-term operating conditions from the screening results for the turbines (Case S14) was modeled for fumigation. Since AERSCREEN is a single point source model, only one of the two turbine stacks were modeled. AERSCREEN results demonstrated that no meteorological conditions met the fumigation criteria. As such, there are no expected impacts resulting from shoreline fumigation and inversion break-up. All of the fumigation impacts are less than the AERSCREEN maxima predicted to occur under normal dispersion conditions anywhere offsite. Since fumigation impacts are less than the maximum overall AERSCREEN impacts, no further analysis of additional short-term averaging times is required. SCAQMD has no comment on applicant's fumigation modeling files and agrees with the applicant's conclusion.

#14 Comment:
HEALTH RISK ASSESSMENT

As described above about all the changes made, SCAQMD used the most recently available and meteorologically-appropriate 5-year data set from Downtown LA/USC station and re-ran HARP with all receptor grids (including the additional receptors on the southern project site due to the

fenceline change, Petition to Amend for Site Delineation, CEC, 2/4/2019) for the project's HRA. The project's health risk impacts are listed in the Table 7 below. The health risks for the entire proposed project are less than the Rule 1401 cancer and non-cancer permit limits of ten in one million (1.0×10^{-05}) with T-BACT and hazard index of 1.0, respectively.

Table 7
SCAQMD's Health Risk Impacts

Total Project (Entire Facility)							
Receptor Type	**Cancer Risk**	**Chronic Hazard Index**	**Acute Hazard Index**	**Cancer Risk Threshold[9]**	**Chronic HI Threshold**	**Acute HI Threshold**	**Exceeds Any Threshold?**
Sensitive	0.88 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	3.96 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Turbine 1							
Sensitive	0.34 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	1.09 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Turbine 2							
Sensitive	0.35 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	1.16 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No

9 For permit units without T-BACT, the increased MICR cannot be greater than the Rule 1401 cancer risk threshold of one in one million (1.0×10^{-6}). For permit units with T-BACT, the increased MICR cannot be greater than the Rule 1401 cancer risk threshold of ten in one million (1.0×10^{-5}).

Firewater Pump							
Sensitive	0.5 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	1.86 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Colling Tower Cell 1							
Sensitive	0.0002 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	0.001 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Colling Tower Cell 2							
Sensitive	0.0002 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	0.001 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Colling Tower Cell 3							
Sensitive	0.0002 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No
Worker	0.001 in one million	<0.1	<0.1	ten in one million (10×10^{-6})	1.0	1.0	No