

DOCKETED

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STANTON ENERGY RELIABILITY CENTER, LLC
650 BERECUT DR.
SACRAMENTO, CA 95811

FACILITY ID: 183501

LOCATION ADDRESS: 10711 Dale Avenue
Stanton, CA 90680

Responsible Official: Kara Miles, President

**PRELIMINARY FINAL DETERMINATION OF COMPLIANCE for
PERMITS TO CONSTRUCT FOR
STANTON ENERGY RELIABILITY CENTER (SERC)**

EQUIPMENT DESCRIPTION

SECTION H: PERMIT TO CONSTRUCT AND TEMPORARY PERMIT TO OPERATE

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions * And Requirements	Conditions
PROCESS 1: INTERNAL COMBUSTION – POWER GENERATION					
GAS TURBINE, NO. 1, SIMPLE-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000 PC SPRINT, 484.2 MMBTU/HR (HHV) AT 40 DEG F, WITH WATER INJECTION WITH A/N: 589935 GENERATOR, 51.049 MW GROSS AT 40 DEG F BATTERY ENERGY STORAGE SYSTEM, 10 MW	D1 [B2] [B16]	C3		CO: 4.0 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; NOx: (9) [40 CFR 72 – Acid Rain Provisions, 11-24-1997]; NOx: 2.5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]; NOx: 25 PPMV NATURAL GAS (8) [40 CFR 60	A63.1, A63.2, A195.1, A195.2, A195.3, A195.5, A327.1, B61.1, C1.1, C1.2, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, E193.2, E193.3, E193.4, H23.1, H23.2, K40.1

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				<p>SUBPART KKKK, 7-6-2006];</p> <p>PM10: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 3.0 LB/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]; PM10: 11 LBS/HR (5B) [RULE 475, 10-8-1976; RULE 475, 8-7-1978];</p> <p>SO2: (9) [40 CFR 72 – Acid Rain Provisions, 11-24-1997]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006];</p> <p>VOC: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]</p>	
CO OXIDATION CATALYST, NO. 1, BASF, MODEL CAMET, 68.2 CU. FT.; WIDTH: 23 FT 4.8 IN; HEIGHT: 25 FT; LENGTH: 2.1 IN A/N: 589937	C3	D1 C4			E193.1, E193.2
SELECTIVE CATALYTIC REDUCTION, NO. 1, CORMETECH, MODEL CUSTOM, TITANIA-BASED CERAMIC, 1385 CU. FT.; WIDTH: 23 FT 4.8 IN; HEIGHT: 25 FT; LENGTH: 2 FT 8 IN WITH A/N: 589937 AMMONIA INJECTION, AQUEOUS AMMONIA	C4 [B5]	C3 S6		<p>NH3: 5 PPMV (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]</p>	A195.4, D12.1, D12.2, D12.3, E193.1, E193.2

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STACK, TURBINE NO. 1, HEIGHT: 71 FT; DIAMETER: 12 FT A/N: 589935	S6	C4			
GAS TURBINE, NO. 2, SIMPLE-CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LM6000 PC SPRINT, 484.2 MMBTU/HR (HHV) AT 40 DEG F, WITH WATER INJECTION WITH A/N: 589936 GENERATOR, 51.049 MW GROSS AT 40 DEG F BATTERY ENERGY STORAGE SYSTEM, 10 MW	D7 [B8] [B17]	C9		CO: 4.0 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]; CO: 2000 PPMV (5) [RULE 407, 4-2-1982]; NOx: (9) [40 CFR 72 – Acid Rain Provisions, 11-24-1997]; NOx: 2.5 PPMV NATURAL GAS (4) [RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]; NOx: 25 PPMV NATURAL GAS (8) [40 CFR 60 SUBPART KKKK, 7-6-2006]; PM10: 0.01 GRAINS/SCF (5A) [RULE 475, 10-8-1976; RULE 475, 8-7-1978]; PM10: 0.1 GRAINS/SCF (5) [RULE 409, 8-7-1981]; PM10: 3.0 LB/HR NATURAL GAS (4) [RULE 1303(b)(2)-Offset, 5-10-1996; RULE 1303(b)(2)-Offset, 12-6-2002]; PM10: 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]; SO2: 0.06 LBS/MMBTU NATURAL GAS (8)	A63.1, A63.2, A195.1, A195.2, A195.3, A195.5, A327.1, B61.1, C1.1, C1.2, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, E193.2, E193.3, E193.4, H23.1, H23.2, K40.1

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				[40 CFR 60 SUBPART KKKK, 7- 6-2006]; VOC: 2 PPMV NATURAL GAS (4) [RULE 1303-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12- 6-2002]	
CO OXIDATION CATALYST, NO. 2, BASF, MODEL CAMET, 68.2 CU. FT.; WIDTH: 23 FT 4.8 IN; HEIGHT: 25 FT; LENGTH: 2.1 IN A/N: 589938	C9	D7 C10			E193.1, E193.2
SELECTIVE CATALYTIC REDUCTION, NO. 2, CORMETECH, MODEL CUSTOM, TITANIA-BASED CERAMIC, 1385 CU. FT.; WIDTH: 23 FT 4.8 IN; HEIGHT: 25 FT; LENGTH: 2 FT 8 IN WITH A/N: 589938 AMMONIA INJECTION, AQUEOUS AMMONIA	C10 [B11]	C9 S12		NH3: 5 PPMV (4) [RULE 1303(a)(1)- BACT, 5-10-1996; RULE 1303(a)(1)- BACT, 12-6-2002]	A195.4, D12.1, D12.2, D12.3, E193.1, E193.2
STACK, TURBINE NO. 2, HEIGHT: 71 FT; DIAMETER: 12 FT A/N: 589936	S12	C10			
PROCESS 2: INORGANIC CHEMICAL STORAGE					
STORAGE TANK, AQUEOUS AMMONIA 19 PERCENT, 5000 GALS; DIAMETER: 10 FT; HEIGHT: 8 FT 6 IN. FT A/N: 589941	D13				C157.1, E144.1, E193.1, E193.2
PROCESS 3: RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE-SPECIFIC RULES					
RULE 219 EXEMPT EQUIPMENT, COATING EQUIPMENT, PORTABLE, ARCHITECTURAL COATING	E14			VOC: (9) [RULE 1113, 6-3-2011; RULE 1113, 2-5- 2016; RULE 1171, 2- 1-2008; RULE 1171, 5-1-2009]	K67.1
RULE 219 EXEMPT EQUIPMENT, AIR CONDITIONING UNITS	E15				H23.3, H23.4

- | | |
|--|---|
| (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.

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FACILITY CONDITIONS

F9.1 Except for open abrasive blasting operations, the operator shall not discharge into the atmosphere from any single source of emissions whatsoever any air contaminant for a period or periods aggregating more than three minutes in any one hour which is:

- (a) As dark or darker in shade as that designated No. 1 on the Ringelmann Chart, as published by the United States Bureau of Mines; or
- (b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subparagraph (a) of this condition.

[RULE 401, 3-2-1984; RULE 401, 11-9-2001]

DEVICE CONDITIONS

TURBINES

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

CONTAMINANT	EMISSIONS LIMIT
NOx	Less than or equal to 3601 LBS IN ANY CALENDAR MONTH
CO	Less than or equal to 3690 LBS IN ANY CALENDAR MONTH
VOC	Less than or equal to 1156 LBS IN ANY CALENDAR MONTH
PM10	Less than or equal to 2237 LBS IN ANY CALENDAR MONTH
PM2.5	Less than or equal to 2237 LBS IN ANY CALENDAR MONTH
SOx	Less than or equal to 758 LBS IN ANY CALENDAR MONTH

For the purposes of this condition, the above monthly emission limits shall be based on the emissions from a single turbine.

The turbine shall not commence with normal operation until the commissioning process has been completed. Normal operation commences when the turbine is able to supply electrical energy to the power grid as required under contract with the relevant entities. The SCAQMD shall be notified in writing once the commissioning process for each turbine is completed.

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Normal operation may commence in the same calendar month as the completion of the commissioning process provided the turbine is in compliance with the above emission limits.

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.

For the commissioning period, CO, VOC, PM10/PM2.5, and SOx emissions shall be calculated using the following emission factors:

Pre-Catalyst Phase: CO, 155.08 lb/mmcf; VOC, 24.60 lb/mmcf; PM10/PM2.5, 32.09 lb/mmcf; and SOx, 2.14 lb/mmcf. The pre-catalyst phase starts with step 1 of the commissioning activities (first fire and full speed, no load, not synchronized, no generator excitation) and ends with ~~step 5 (full load operation with water injection and SPRINT in service)~~ step 3 (first synchronization). The steps referenced herein are described in the Commissioning Emissions (per Turbine) table provided by Stanton Energy Reliability Center.

Post-Catalyst Phase: CO, 6.70 lb/mmcf; VOC, 3.42 lb/mmcf; PM10/PM2.5, 8.29 lb/mmcf; and SOx, 2.14 lb/mmcf. The post-catalyst phase starts with step 4 of the commissioning activities (synchronization and ramp to full load, tuning water, ammonia (rough), and AVR (as needed), gas compressor turning) and ends with ~~is comprised of step 6 of the commissioning activities~~ (full load operation with water injection and SPRINT in service and SCR/ammonia tuning).

For the commissioning period (pre-catalyst and post-catalyst phases), NOx emissions shall be measured with an SCAQMD Method 100.1 source test van CEMS.

For normal operation, VOC, PM10/PM2.5, and SOx emissions shall be calculated using the following emission factors: VOC, 3.26 lb/mmcf; PM10/PM2.5, 6.32 lb/mmcf; and SOx, 2.14 lb/mmcf (based on 0.75 grains S/100 scf).

For normal operation, the NOx and CO emission shall be measured with certified NOx CEMS and CO CEMS, respectively. For the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the emission factors shall be as follows: NOx, 10.17 lb/mmcf; CO, 10.42 lb/mmcf.

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, natural gas usage in a calendar month and automated monthly and annual calculated emissions.

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

[Devices subject to this condition: D1, D7]

A63.2 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSIONS LIMIT
NOx	Less than or equal to 7848 LBS IN ANY ONE YEAR
CO	Less than or equal to 9143 LBS IN ANY ONE YEAR
VOC	Less than or equal to 3432 LBS IN ANY ONE YEAR
PM10	Less than or equal to 5412 LBS IN ANY ONE YEAR
PM2.5	Less than or equal to 5412 LBS IN ANY ONE YEAR
SOx	Less than or equal to 595 LBS IN ANY ONE YEAR

For the purposes of this condition, the above annual emission limits shall be based on the total combined emissions from both turbines (D1 and D7).

The ~~yearly~~ annual emissions ~~limits~~ of the facility for purposes of demonstrating compliance with ~~in~~ this condition shall be calculated from the monthly emissions, including emissions for the commissioning period, as required by condition A63.1, except the normal operation annual emission factor for SOx is 0.72 lb/mmcf (based on 0.25 grains S/100 scf (annual average)).

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, natural gas usage in a calendar month and automated monthly and annual calculated emissions.

[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: D1, D7]

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A195.1 The 2.5 PPMV NO_x emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen.

This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

[Devices subject to this condition: D1, D7]

A195.2 The 4.0 PPMV CO emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen.

This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

[Devices subject to this condition: D1, D7]

A195.3 The 2.0 PPMV VOC emission limit is averaged over 1 hour, dry basis at 15 percent oxygen.

This limit shall not apply to turbine commissioning, startup, and shutdown periods.

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

[Devices subject to this condition: D1, D7]

A195.5 The 25 PPMV NO_x emission limit(s) is averaged over 1 hour, dry basis at 15 percent oxygen.

This limit shall not apply to turbine commissioning, startup, and shutdown periods.

[40 CFR 60 Subpart KKKK, 7-6-2006]

[Devices subject to this condition: D1, D7]

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: D1, D7]

B61.1 The operator shall not use natural gas containing the following specified compounds:

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<u>Compound</u>	<u>Range</u>	<u>Grain per 100 scf</u>
H2S	Greater than	0.25

This concentration limit is an annual average based on monthly samples of natural gas composition or gas supplier documentation. Gaseous fuel samples shall be tested using District Method 307-91 for total sulfur calculated as H2S.

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

[Devices subject to this condition: D1, D7]

C1.1 The operator shall limit the number of start-ups to no more than 124 in any one calendar month.

For the purposes of this condition, the limits are for one turbine, except the annual limit is the combined total for two turbines (D1 and D7). The number of startups shall not exceed 4 startups in any one day. The number of startups shall not exceed 1000 in any calendar year.

A startup shall not exceed 15 minutes. The NOx emissions from a startup shall not exceed 3.6 lbs. The CO emissions from a startup shall not exceed 5.3 lbs.

The beginning of startup occurs at initial fire in the combustor and the end of startup occurs when the BACT levels are achieved. If during startup the process is aborted the process will count as one startup.

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.

[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: D1, D7]

C1.2 The operator shall limit the number of shutdowns to no more than 124 in any one calendar month.

For the purposes of this condition, the limits are for one turbine, except the annual limit is the combined total for two turbines (D1 and D7). The number of shutdowns shall not exceed 4 shutdowns in any one day. The number of shutdowns shall not exceed 1000 in any calendar year.

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Each shutdown shall not exceed 10 minutes. The NOx emissions from a shutdown event shall not exceed 0.55 lbs. The CO emissions from a shutdown event shall not exceed 0.24 lbs.

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. The records shall be maintained for a minimum of 5 years in a manner approved by 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: D1, D7]

D29.1 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
NOx emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
CO emissions	District Method 100.1	1 hour	Outlet of the SCR serving this equipment
SOx emissions	AQMD Laboratory Method 307-91	District-Approved Averaging Time	Fuel Sample
VOC emissions	District Method 25.3 Modified	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A/ District Method 5.1	District-approved averaging time	Outlet of the SCR serving this equipment
PM2.5	EPA Method 201A and 202	District-approved averaging time	Outlet of the SCR serving this equipment
NH3 emissions	District Method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR serving this equipment

Note: SCAQMD Source Testing Dept. indicates District Method 207.1 is the current standard ammonia source test method.

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The test shall be conducted after District approval of the source test protocol, but no later than 180 days after initial start-up. 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 determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW-gross and MW-net.

The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the SCAQMD engineer no later than 90 days before the proposed test date and shall be approved by the District before the test commences.

The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The sampling time for the PM10 and PM2.5 tests shall be 4 hours or longer as necessary to obtain a measureable amount of sample.

The tests shall be conducted when the turbine is operating at loads of 50, 75, and 100 percent of maximum load.

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

- a) Triplicate stack gas samples extracted directly into Summa canisters, maintaining a final canister pressure between 400-500 mm Hg absolute,
- b) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and
- c) Analysis of Summa canisters per 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.

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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.

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

[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: D1, D7]

D29.2 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
SOx emissions	AQMD Laboratory Method 307-91	District-Approved Averaging Time	Fuel Sample
VOC emissions	District method 25.3 Modified	1 hour	Outlet of the SCR serving this equipment
PM10 emissions	EPA Method 201A/ District Method 5.1	District-Approved Averaging Time	Outlet of the SCR serving this equipment

The test(s) shall be conducted at least once every three years.

The test shall be conducted in accordance with a District approved source test protocol. The test shall be conducted and the results submitted to the District within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

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 when the turbine is operating at 100 percent of maximum load.

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

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- b) Pressurization of the Summa canisters with zero gas analyzed/certified to less than 0.05 ppmv total hydrocarbons as carbon, and
- c) Analysis of Summa canisters per 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.

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

[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: D1, D7]

D29.3 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

Note: SCAQMD Source Testing Dept. indicates District Method 207.1 is the current standard ammonia source test method.

The test shall be conducted in accordance with a District approved source test protocol. The test shall be conducted and the results submitted to the District within 60 days after the test date. The SCAQMD shall be notified of the date and time of the test at least 10 days prior to the test.

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The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. 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.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit.

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

[Devices subject to this condition: D1, D7]

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 for the purpose of demonstrating compliance with the BACT limit of 4.0 ppmvd CO at 15% O2.

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

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved SCAQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD.

The initial certification testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. For the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the operator shall use the emission factor for CO provided in condition A63.1 for these purposes.

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

CO Emission Rate, lbs/hr = $K * C_{co} * F_d [20.9 / (20.9\% - \%O_2 d)] [(Q_g * HHV) / 10E+06]$,
where:

1. $K = 7.267 * 10E-08$ (lb/scf)/ppm
2. C_{co} = Average of four consecutive 15 min. average CO concentrations, ppm

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3. $F_d = 8710$ dscf/MMBTU natural gas
4. $\%O_2 d$ = Hourly average % by volume O_2 dry, corresponding to C_{co}
5. Q_g = Fuel gas usage during the hour, scf/hr
6. HHV = Gross high heating value of fuel gas, BTU/scf

[RULE 218, 5-14-1999; RULE 218.1, 5-14-1999; RULE 218.1, 5-14-2012; RULE 1303(a)(1)-BACT, 5-10-1996; RULE 1303(a)(1)-BACT, 12-6-2002]

[Devices subject to this condition: D1, D7]

D82.2 The operator shall install and maintain a CEMS to measure the following parameters:

NO_x concentration in ppmv.

Concentrations shall be corrected to 15 percent oxygen on a dry basis for the purpose of demonstrating compliance with the BACT limit of 2.5 ppmvd NO_x at 15% O₂.

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

The CEMS will convert the actual NO_x concentrations to mass emission rates (lb/hr) and record the hourly emission rates on a continuous basis.

The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved CEMS certification application submitted in compliance with 40 CFR Part 60 Subpart KKKK and 40 CFR Part 75. The operator shall not install the CEMS prior to receiving initial approval from SCAQMD.

The initial certification testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the conclusion of the commissioning period and the provisional certification date of the CEMS, and in the event of CEMS failure subsequent to CEMS certification, the operator shall use the emission factor for NO_x provided in condition A63.1 for these purposes.

The NO_x CEMS shall comply with the requirements of conditions D82.2, H23.1, and H23.2.

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[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; 40 CFR 60 Subpart KKKK, 7-6-2006; 40 CFR 75-Acid Rain CEM, 1-18-2012]

[Devices subject to this condition: D1, D7]

- E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 16-AFC-01 project.

[CA PRC CEQA, 5-12-2017]

[Devices subject to this condition: D1, C3, C4, D7, C9, C10, D13]

- E193.2 The operator shall install this equipment according to the following requirements:

The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment, in which case the Permit to Construct serves as a temporary Permit to Operate.

[RULE 202, 5-7-1976; RULE 202, 12-3-2004; RULE 205, 1-5-1990]

[Devices subject to this condition: D1, C3, C4, D7, C9, C10, D13]

- E193.3 The operator shall operate and maintain this equipment according to the following requirements:

Total commissioning hours shall not exceed 100 hours of fired operation for each turbine from the date of initial turbine start-up. Of the 100 hours, commissioning hours without control (pre-catalyst phase as defined in condition A63.1) shall not exceed ~~38~~ 20 hours.

Two turbines may be commissioned at the same time.

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 provide the SCAQMD with written notification of the initial startup date of each turbine.

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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. The records shall include, but not be limited to, the total number of commissioning hours, number of commissioning hours without control, natural gas fuel usage for the pre-catalyst phase, and natural gas fuel usage for the post-catalyst phase (pre-catalyst and post-catalyst phases as defined in condition A63.1).

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

[Devices subject to this condition: D1, D7]

E193.4 The operator shall upon completion of the construction, operate and maintain this equipment according to the following requirements:

The 120 lbs/MMBtu CO2 emission limit for non-base load turbines shall apply.

Compliance with the 120 lbs/MMBtu CO2 emission limit shall be determined on a 12-operating-month rolling average basis.

This turbine shall be operated in compliance with all applicable requirements of 40 CFR 60 Subpart TTTT, including applicable requirements for recordkeeping and reporting.

[40 CFR 60 Subpart TTTT, 10-23-2015]

[Devices subject to this condition: D1, D7]

H23.1 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

The NOx CEMS shall comply with the requirements of conditions D82.2, H23.1, and H23.2.

The NOx CEMS shall comply with the applicable requirements of §60.13, §60.4335(b), §60.4340(b)(1) and §60.4345 for monitoring.

The NOx CEMS shall comply with the applicable requirements of §60.4350 for identifying excess emissions.

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The operator shall comply with the requirements of §60.7(c), §60.4375, §60.4380, and §60.4395 for reporting excess emissions and monitor downtime.

The performance evaluation of the NOx CEMS shall be conducted as part of the initial performance test of the turbine required no later than 180 days after initial start-up by §60.8, in accordance with the requirements of §60.4405. The initial performance test of the turbine shall be conducted to demonstrate compliance with the §60.4320 limit of 25.0 ppmv NOx at 15% O2, 1-hour averaging.

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

[Devices subject to this condition: D1, D7]

H23.2 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

The NOx CEMS shall comply with the requirements of conditions D82.2, H23.1, and H23.2.

The operator shall comply with the applicable requirements of §75.4 for monitoring systems installation and certification testing compliance dates.

The NOx CEMS shall comply with the applicable requirements of §75.10 for general operating requirements.

The NOx CEMS shall comply with the applicable requirements of §75.12 for specific provisions for monitoring NOx emission rate.

The operator shall comply with §75.20 for the initial certification requirements for the NOx CEMS.

The operator shall comply with §75.21 for the quality assurance and quality control requirements for the NOx CEMS.

The operator shall use the reference test methods in §75.22, or equivalent method(s) approved by the EPA.

The operator shall comply with §75.24 for out-of-control periods and adjustment for system bias requirements for the NOx CEMS.

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The operator shall comply with the applicable requirements of Subpart D--Missing Data Substitution Procedures.

The operator shall comply with the applicable requirements of Subpart F—Recordkeeping Requirements.

The operator shall comply with the applicable requirements of Subpart G—Reporting Requirements.

The operator shall measure and record SO₂ emissions by using the applicable procedures specified in appendix D to Part 75 for estimating hourly SO₂ mass emissions, pursuant to §75.11(d)(2).

The operator shall measure and record CO₂ emissions by following the procedures in appendix G to Part 75 for estimating daily CO₂ mass emissions, pursuant to §75.10(a)(3)(ii) and §75.13(b).

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

[Devices subject to this condition: D1, D7]

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

Source test results shall be submitted to the District no later than 90 days after the source tests required by conditions D29.1, D29.2, and D29.3 are conducted.

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

All exhaust flow rates 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, the fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) 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]

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[Devices subject to this condition: D1, D7]

SCR/CO CATALYSTS

A195.4 The 5.0 PPMV NH₃ emission limit is averaged over 1 hour, dry basis at 15 percent oxygen.

This limit shall not apply to turbine commissioning, startup, and shutdown periods.

The operator shall calculate and continuously record the NH₃ slip concentration using the following equation:

NH₃ (ppmv) = [a-b*c/1,000,000]*1,000,000/b, where:

a = NH₃ injection rate (lb/hr)/17(lb/lb-mol)

b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)

c = change in measured NO_x across the SCR (ppmv at 15% O₂)

The operator shall install and maintain a NO_x analyzer to measure the SCR inlet NO_x ppmv accurate to within plus or minus 5 percent calibrated at least once every 12 months. The operator shall use the method described above or another alternative method approved by the Executive Officer.

The ammonia slip calculation procedure shall be in effect no later than 90 days after initial startup of the turbine.

The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.

The District may require the installation of a CEMS designed to monitor ammonia concentrations if the District determines that a commercially available CEMS has been proven to be accurate and reliable and that an adequate Quality Assurance/Quality Control protocol for the CEMS has been established. The District or another agency must establish a District approved Quality Assurance/Quality Control protocol prior to the ammonia CEMS being a requirement.

The above ammonia slip calculation and the annual testing under D29.3 shall not be required if a District approved ammonia CEMS is installed.

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

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[Devices subject to this condition: C4, C10]

- D12.1 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. Continuously record shall be defined as measuring at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The flow meter 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 15 and 200 pounds per hour, except during startups and shutdowns.

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

[Devices subject to this condition: C4, C10]

- D12.2 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured. Continuously record shall be defined as measuring at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

The temperature 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 460 degrees F and 855 degrees F, except during startups and shutdowns.

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

[Devices subject to this condition: C4, C10]

- D12.3 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. Continuously record shall be defined as measuring at least once every

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month and shall be calculated based upon the average of the continuous monitoring for that month.

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

The pressure differential shall not exceed 6.0 inches water column.

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

[Devices subject to this condition: C4, C10]

- E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 16-AFC-01 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D1, C3, C4, D7, C9, C10, D13]

- E193.2 The operator shall install this equipment according to the following requirements:

The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment, in which case the Permit to Construct serves as a temporary Permit to Operate.

[RULE 202, 5-7-1976; RULE 202, 12-3-2004; RULE 205, 1-5-1990]

[Devices subject to this condition: D1, C3, C4, D7, C9, C10, D13]

AMMONIA TANK

- C157.1 The operator shall install and maintain a pressure relief valve set at 2.3 psig.

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

[Devices subject to this condition: D13]

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E144.1 The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.

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

[Devices subject to this condition: D13]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following requirements:

In accordance with all air quality mitigation measures stipulated in the final California Energy Commission decision for the 16-AFC-01 project.

[CA PRC CEQA, 11-23-1970]

[Devices subject to this condition: D1, C3, C4, D7, C9, C10, D13]

E193.2 The operator shall install this equipment according to the following requirements:

The Permit to Construct listed in Section H shall expire one year from the Permit to Construct issuance date, unless a Permit to Construct extension has been granted by the Executive Officer or unless the equipment has been constructed and the operator has notified the Executive Officer prior to the operation of the equipment, in which case the Permit to Construct serves as a temporary Permit to Operate.

[RULE 202, 5-7-1976; RULE 202, 12-3-2004; RULE 205, 1-5-1990]

[Devices subject to this condition: D1, C3, C4, D7, C9, C10, D13]

RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE-SPECIFIC RULES

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

Contaminant	Rule	Rule/Subpart
Refrigerants	District Rule	1415

[Rule 1415, 12-3-2010]

[Devices subject to this condition: E15]

H23.4 This equipment is subject to the applicable requirements of the following Rules or Regulations:

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Contaminant	Rule	Rule/Subpart
Refrigerants	40 CFR 82, Subpart	F

[40 CFR 82 Subpart F, 6-25-2013]

[Devices subject to this condition: E15]

K67.1 The operator shall keep records, in a manner approved by the district, for the following parameter(s) or item(s):

For architectural applications where no thinners, reducers, or other VOC containing materials are added, maintain semi-annual records for all coating consisting of (a) coating type, (b) VOC content as supplied in grams per liter (g/l) of materials for low-solids coatings, (c) VOC content as supplied in g/l of coating, less water and exempt solvent, for other coatings.

For architectural applications where thinners, reducers, or other VOC containing materials are added, maintain daily records for each coating consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

[RULE 3004(a)(4) - Periodic Monitoring, 12-12-1997]

[Devices subject to this condition: E14]

BACKGROUND AND FACILITY DESCRIPTION

Project Description

On November 2, 2016, Stanton Energy Reliability Center, LLC (SERC) submitted the application package (Application) for Permits to Construct two simple-cycle turbines equipped with integrated battery storage systems, two control systems, and an aqueous ammonia tank. SERC, a joint venture of W Power, LLC and Wellhead Energy, LLC, will construct, own, and operate the SERC.

The SERC will be a hybrid electrical generating and storage facility, consisting of two General Electric (GE) LM6000 PC-based EGTs. EGT refers to the LM6000 PC Hybrid EGT jointly developed by General Electric International, Inc. and Wellhead Power Solutions. Each EGT will consist of a GE LM6000 PC natural gas-fired, simple-cycle combustion turbine, a clutch to provide operational flexibility as a synchronous condenser, and an integrated 10-megawatt (MW) GE Battery Energy Storage System. In total, SERC will provide 98 MW (nominal) of EGT capacity, and, specifically, a gross generating capacity of 102.098 megawatts (MW) and net generating capacity of 99.274 MW at 40 °F ambient temperature.

For the purpose of a turbine equipment description on a facility permit, the applicable operating scenario is the scenario that yields the highest Btu/hr consumption for the turbine. From *Table 7 -*

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Turbine Operating Scenarios, below, the applicable operating scenario is Case 106, based on 100% load, 40 °F ambient temperature, without evaporative cooling of the combustion air, for a fuel input per turbine of 484.2 MMBtu/hr. At those conditions, each combustion turbine generator is rated 51.049 MW-gross and 49.637 MW-net.

Two selective catalytic reduction (SCR) systems will be used for control of NO_x, and two CO oxidation catalysts will be used for control of CO and VOC emissions. One 5,000-gallon ammonia (NH₃) storage tank will store 19% aqueous ammonia which is the reducing agent in the SCRs.

SERC will provide needed generation for local reliability in the Southern California Edison (SCE) West Los Angeles Basin Subarea. The need is caused by the closure of the San Onofre Nuclear Generating Station and anticipated retirement of aging, coastal plants currently using once-through ocean water cooling. SERC and SCE entered into a Resource Adequacy Purchase Agreement (RAPA) as part of SCE's 2013 Local Capacity Requirements Request for Offers sanctioned by the California Public Utility Commission (CPUC) to address this specific need. The RAPA has been approved by the CPUC. SERC and SCE entered into a second RAPA as part of SCE's 2014 Energy Storage Request for Offers, which was approved by the CPUC in September 2016. SERC will interconnect to the electrical grid at SCE's Barre Substation, which has available transmission capacity to serve the West LA Basin.

As a reliability plant, the SERC is expected to operate during periods of increased need on the grid such as times of high electrical load, during periods when intermittent renewable source generation fluctuates, when baseload plants are not operating or being brought online, or during emergency conditions. SERC expects the energy storage system to enable the EGT to be used for greenhouse gas (GHG)-free operating reserve, frequency regulation, and voltage regulation.

With battery storage and using EGT capability, SERC can provide power, without a turbine startup time, from the battery array for immediate voltage support. The SERC will have an annual capacity factor of 11 percent or less and will provide a flexible resource to meet local capacity requirements and facilitate renewable energy integration. SERC is also configured to operate as a synchronous condenser and, as such, SERC will provide additional voltage support to maintain balance and stabilize the grid without consuming natural gas. Clutches installed on each gas turbine allow the facility to start and convert to a non-combustion operation that does not produce electricity, but is able to provide voltage support services to the local grid. SERC would be dispatched by the California Independent System Operator (CAISO) or SCE to operate in this configuration when energy generation is not needed from the SERC but the transmission system requires voltage support.

SERC will be located in an area that is zoned Industrial General (City of Stanton IG zoning district). Land uses surrounding the site include the City of Stanton's industrial area to the north and south, public/quasi-public utility areas to the east consisting of the SCE Barre Peaker power plant and Barre Substation, and high- and medium-density residential uses to the southeast and northwest.

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The facility will be a Title V facility because it will be subject to the Acid Rain program, but not a RECLAIM facility.

Proposed Schedule

Construction of the generating facility from site preparation and grading to commercial operation is expected to take place from November 2018 to December 2019 (approximately 14 months total). From *Table 2.1-3 Major Project Milestones* in the Application, the project milestones are listed in the following table.

Table 1 – Stanton Major Project Milestones

Activity	Dates
Begin Construction	November 1, 2018
Startup and Test	September 15, 2019
Commercial Operation	December 31, 2019

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. Its certified program, however, does require environmental analysis of the project, including an analysis of alternatives and mitigation measures to minimize any significant adverse effect the project may have on the environment.

The CEC’s certification process subsumes all requirements of local, regional, state, and federal agencies required for the construction of a new plant. The CEC coordinates its review of the proposed facility with the agencies that will be issuing permits to ensure that its certification incorporates the conditions that are required by these various agencies. As the SERC will be rated at greater than 50 megawatts, it is subject to the CEC’s certification process. On 10/26/16, SERC submitted an Application for Certification (AFC) (16-AFC-01) to the CEC for the SERC project. On 3/8/17, CEC accepted the AFC as “data adequate.”

SCAQMD Applications Submitted

SERC submitted the following applications to the SCAQMD for Permits to Construct for the SERC project. The environmental consultant is Greg Darvin, Atmospheric Dynamics.

The applications and fees, submitted versus required, are summarized below. Rule 301—Permitting and Associated Fees, as amended on 7/1/16, is applicable.

- The two turbines and the two selective catalytic reduction/CO oxidation catalyst systems, respectively, 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,

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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.”

Table 2 - Applications for Permits to Construct Submitted to SCAQMD

Application No.	Submittal Date	Deemed Complete Date	Equipment Description	Fees Submitted	Fees Required
589935	11/2/16	2/24/17	Simple-Cycle Turbine No. 1*	\$28,406.19	\$5420.06 (Schedule D) * 1.5 (XPP) = \$8130.09
589936	11/2/16	2/24/17	Simple-Cycle Turbine, No. 2 (identical)	\$14,203.10	[\$5420.06 x 0.5 (identical)] * [1.5 (XPP)] = \$4065.05
589937	11/2/16	2/24/17	Selective Catalytic Reduction (SCR) No. 1	\$6571.45	\$3927.10 (Schedule C) * 1.5 (XPP) = \$5890.65
589938	11/2/16	2/24/17	Selective Catalytic Reduction No. 2 (identical)	\$3285.73	[\$3927.10 * 0.5 (identical)] * [1.5 (XPP)] = \$2945.33
589939	11/2/16	2/24/17	CO Oxidation Catalyst No. 1	\$6571.45	\$0.00—Application rejected.
589940	11/2/16	2/24/17	CO Oxidation Catalyst No. 2 (identical)	\$3285.73	\$0.00—Application rejected.
589941	11/2/16	2/24/17	Aqueous Ammonia Tank	\$6,911.85	\$1557.83 (Schedule A) * 1.5 (XPP) = \$2336.75.
589974	11/2/16	2/24/17	Initial Title V Permit	\$0.00	\$1,623.07
			Total Fees Submitted	\$69,235.50	
			Total Fees Required		\$24,990.94
			Refund		\$44,244.56 (refund check 3/3/17)

* Note that although the gross MW rating on the permit is >50 MW for one case at low ambient temperature, past practice has been to base fees on gross MW at normal condition which is <50 MW; therefore, fee schedule D is appropriate in this case.

In an e-mail, dated 11/17/16, SERC confirmed there will be no oil/water separators at the site.

Fees Required—As shown in the table above, for two identical equipment, the first equipment is charged full fee and the second is charged 50% of the full fee. In addition, SERC requested expedited permit processing (XPP). For XPP, the fee is an additional 50% of the applicable base permit processing fee, after taking any discounts for identical equipment. The CO Oxidation Catalyst applications were rejected because one application is required for an SCR/CO catalyst system.

Fee Submitted—On 2/24/17, in response to SCAQMD request for clarification, SERC provided a copy of a permit processing fee calculator print-out on, from the SCAQMD website, dated 2/2/17, for a total fee of \$41,465.62 but did not provide an explanation for the \$69,235.50 originally submitted. The reasons for the incorrect fees submitted are: (1) selection of incorrect equipment schedules, (2) unexplained doubling of the fees for the turbines, (3) submittal of separate applications for the CO

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oxidation catalyst systems and SCR, and (4) inclusion of administrative Title V permit revision fees for each type of equipment, instead of an initial Title V permit fee.

Note: A/N 589935 is the master file.

Applications Deem Completion Chronology

On 11/2/16, SERC submitted the application package (Application). On 12/2/16, SCAQMD issued an additional information letter. On 12/29/16, SERC provided a response letter with attachments (SERC Response Letter, 12/29/16). On 2/2/17, SCAQMD issued a second additional information letter. On 2/15/17, SERC provided a response letter with attachments (SERC Response Letter, 2/15/17). On 2/24/17, SCAQMD issued a third additional information letter, but deemed the Application complete to allow the CEC to move forward with the project. On 5/17/17, SERC provided a response letter with attachments (SERC Response Letter, 5/17/17). On 10/6/17, SCAQMD issued a fourth additional information letter. On 10/31/17, SERC provided a response letter (SERC Response Letter, 10/31/17). On 11/7/17, SERC forwarded the emissions guarantee letter for the control systems.

PROCESS DESCRIPTION

SERC will be a hybrid generating facility consisting of two power blocks, with each power block containing a single LM6000 PC Hybrid EGT and control equipment.

1. A/N 589935, 589936—Simple-Cycle Combustion Turbine Generators (CTGs) Nos. 1 and 2
The two LM6000 PC Hybrid EGTs will include the following equipment.

- Two General Electric LM6000 PC natural-gas fired combustion turbine generators (CTGs). Each combustion turbine generator is rated at 51.049 MW-gross and 49.637 MW-net at 40 °F.
 - Each CTG is equipped with an inlet air fogging system. As ambient temperatures rise, the output of CTGs decrease. Inlet air cooling systems minimize these effects. Combustion air for each CTG will be cooled via the use of a fogging-based system. Fogging systems are based upon the extremely high pressurization of demineralized water being forced through nozzles to create a fine mist or fog. The fogging system will cool the inlet air to the wet bulb temperature of the inlet air. The fogging system will be in service only when a CTG is at or near full load, and will not be placed in service for ambient dry bulb conditions below 50 °F.
 - Each CTG is equipped with GE’s SPRay INtercooled (SPRINT) technology for power augmentation. SPRINT provides a spray of demineralized water into the air stream at the inlet of the CTG’s low pressure compressor. As the demineralized water flows through the low pressure compressor, the heat of compression vaporizes the water spray, absorbing heat as it cools and compresses (makes denser) the air flow, allowing for increased mass flow and subsequently more power production.

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- Each CTG is equipped with a water injection system for NOx control. This system injects demineralized water into the combustor through the fuel nozzles to reduce the combustor flame temperature and lower NOx emissions.
- Two 10 MW/5 MWh lithium-ion battery energy storage systems (BESSs). The BESSs can be operated in conjunction with the combustion turbine generators using the proprietary EGT Hybrid technology, jointly developed by Wellhead and GE. Each BESS will consist of three main components: batteries, inverters, and Balance of Plant (BOP) (e.g., step-up transformers and site controller). Each BESS will be installed in a purpose built battery enclosure to meet fire protection requirements and provide secondary containment.

BESSs are rated both in terms of power and stored energy. Each BESS is capable of producing 10 MW of power and storing 5 MWh of energy. Both of these ratings were determined by the hybrid designers to allow the LM6000 PC Hybrid EGTs to provide generator characteristics necessary to fully qualify the units for Spinning Reserve status according to CAISO’s tariff rules. This amount of power and stored energy allows each unit to immediately begin delivering power to the grid and ramp from 0.0 MW to 49 MW (nominal) within 10 minutes of receipt of a Spinning Reserve instruction. The BESS is capable of discharging at any power output (0 to 10 MW) until the BESS’s stored energy (5 MWh nominal) is discharged. Actual BESS power output levels and durations during ramping are controlled by the Hybrid Control System (HCS). Power output and stored energy levels are optimized by the HCS, and will vary over the course of a run instruction, even if the Gas Turbine remains offline in its GHG-free Spinning Reserve mode.

In the CTGs, combustion air flows through the filters and associated air inlet ductwork, and then is compressed in the gas turbine compressor section, before flowing to the LM6000 PC single annular combustor. Natural gas is injected along with the compressed air into the combustor and is then ignited. The hot combustion gases expand through the power turbine section of the CTG, causing the shaft to rotate and drive the electric generator and CTG compressor. Therefore, thermal energy is produced in each CTG through the combustion of natural gas, which is converted into the mechanical energy required to drive the combustion turbine compressors and electric generators. The GE LM6000 PC CTG is a two-shaft/two-spool engine consisting of a low-pressure compressor, a high-pressure compressor, a high-pressure turbine, and a low-pressure turbine. The engine is connected to the generator.

The following table lists the technical specifications for the simple-cycle turbines. The case numbers are from *Table 7—Turbine Operating Scenarios*, below.

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Table 3 – Turbine Specifications

Turbine Parameters	Specifications
Manufacturer	General Electric
Model	LM6000 PC Sprint
Fuel Type	Pipeline natural gas
Maximum Turbine Power Output, Gross	51.049 MW-gross at 40 °F (Case 106)
Maximum Turbine Power Output, Net	49.637 MW-net at 40 °F (Case 106)
Maximum Turbine Heat Input	484.2 MMBtu/hr (HHV) at 40 °F (Case 106)
Turbine Heat Input at Average Ambient Temperature	468.5 MMBtu/hr (HHV) at 65 °F (Case 103)
Maximum Project Power Output, Gross (two CTGs)	102.098 MW-gross at 40 °F (Case 106)
Maximum Project Power Output, Net (two CTGs)	99.274 MW-net at 40 °F (Case 106)
NOx Combustion Control	Water injection, 25 ppmvd at 15% O ₂

Each CTG is equipped with an emission reduction system consisting of a CO catalyst and SCR in the outlet ductwork, as discussed below.

2. A/N 589937, 589938—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. 1 and 2
Each simple-cycle turbine will be equipped with an oxidation catalyst and a selective catalytic reduction system.

- CO Oxidation Catalyst

The CO oxidation catalyst, located between the turbine and the SCR, will be used to control CO and VOC emissions. The catalyst will reduce CO emissions from 37.4 ppmv (Case 107) to 4 ppmv, all 1-hr averages, dry basis at 15% O₂. The catalyst will reduce the VOC from 4.3 ppm (Case 107) to 2 ppmv, all 1-hour averages, dry basis at 15% O₂.

The following table lists the technical specifications for the CO oxidation catalyst.

Table 4 – CO Oxidation Catalyst Specifications

Catalyst Parameters	Specifications
Manufacturer	BASF Corp.
Model	Camet
Catalyst Type	Platinum Group Metals
Catalyst Guaranteed Life	Mitsubishi Hitachi Power Systems Americas, Inc.—Five years
Space Velocity	226,028 per hour
Catalyst Volume	68.2 ft ³
CO removal efficiency	89%
CO at stack outlet	4.0 ppmvd at 15% O ₂
VOC at stack outlet	2.0 ppmvd at 15% O ₂
Operating Temperature	480 - 850 °F

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- Selective Catalytic Reduction

The CTGs will use water injection to reduce the NO_x concentration to 25 ppmvd in the turbine exhaust, as discussed above. The SCR catalyst will use ammonia injection in the presence of catalyst to further reduce the NO_x concentration in the exhaust gases. Diluted 19% aqueous ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst. The resulting reaction will reduce NO_x to elemental nitrogen and water, resulting in NO_x concentrations in the exhaust gas decreasing from 25 ppmvd to 2.5 ppmvd, all 1-hour averages, dry basis at 15% O₂. The ammonia slip will be limited to 5 ppmvd at 15% O₂. Each SCR will be vented through a dedicated stack, which is 12 feet diameter and 71 feet high.

The ammonia flow rate shall be between 15 and 200 pounds per hour, as required by condition D12.1. The exhaust temperature is required to be between 460 and 855 °F, as specified in condition D12.2. The minimum temperature is required to protect the catalyst face from ammonia salt formation and deposition on a cold catalyst. The maximum temperature is required to maintain catalyst effectiveness. The pressure drop across the catalyst shall be no greater than 6.0 inches water column, as required by condition D12.3. (The final parameters for the ammonia flow rate range, exhaust temperature range, and maximum pressure drop across the catalyst were provided in the SERC Response Letter, 10/31/17.)

The following table lists the technical specifications for the SCR.

Table 5 – Selective Catalytic Reduction Specifications

Catalyst Parameters	Specifications
Manufacturer	Cormetech
Catalyst Description	Titania-based ceramic
Catalyst Model No.	Custom
Catalyst Volume	1385 ft ³
Reactor Dimensions	23.4 ft wide x 25 ft high x 2.667 ft long
Catalyst Guaranteed Life	Mitsubishi Hitachi Power Systems Americas, Inc.—Five years
Space Velocity	26,860 per hr
Ammonia Injection Rate	15 - 200 lb/hr
Ammonia Slip	5 ppm at 15% O ₂
NO _x removal efficiency	90%
NO _x at stack outlet	2.5 ppmv at 15% O ₂
Operating Temperature	460 - 855 °F
Pressure Drop	6.0 inches water column

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- Performance and Catalyst Life Warranties
 - Performance Warranty
Mitsubishi Hitachi Power Systems Americas, Inc. (MHPS) is working with SERC to finalize a Purchase Agreement to provide two emissions reduction units (SCR/CO oxidation catalyst systems). MHPS provided a guarantee letter, dated 11/7/17, for the controlled NO_x, CO, VOC and NH₃ emissions levels. The warranted emissions levels are summarized in the table below.

Table 6 - Turbine Warranted Emissions for Control Systems

Pollutants	Warranted Emissions
NO _x	2.5 ppmvd at 15% O ₂
CO	4.0 ppmvd at 15% O ₂
VOC	2 ppmvd at 15% O ₂
NH ₃	5 ppmvd at 15% O ₂

For a detailed discussion of the Best Available Control Technology (BACT) levels versus guaranteed levels, see the BACT analysis under *Regulation XIII—New Source Review (NSR)* below.

- Catalyst Life Warranties
The MHPS letter, dated 11/7/17, also provided a five-year catalyst life guarantee for the SCR/CO oxidation catalyst systems.

3. A/N 589941—Aqueous Ammonia Storage Tank

The Form 400-E-18—Storage Tank provided in A/N 589941 is superseded by additional information provided in the SERC Response Letter, 10/31/17.

The 5,000-gallon ammonia tank will provide ammonia to the two SCRs for the turbines. Aqueous ammonia, 19% by weight, will be delivered by tanker truck. The maximum number of deliveries is estimated to be six per month, with each shipment approximately 3200 gallons. The maximum number of annual deliveries is 11 per year, with each shipment approximately 2125 gallons. Deliveries will typically be requested prior to the tank becoming completely empty.

To control the filling losses, the tanker truck will connect a filling line and a vapor return line to the SERC aqueous ammonia unloading system. The vapor return line allows vapors accumulated in the headspace of the aqueous ammonia tank to be returned to the ammonia tanker truck during filling operations. Condition E144.1 requires the operator to vent the tank, during filling, only to the vessel from which it is being filled.

The tank will be equipped with a pressure relief valve set at 2.3 psig. Breathing losses are not expected under normal operating conditions, because the total vapor pressure of 19% aqueous

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ammonia at 120 °F is 14.4 psia. Condition C157.1 requires a pressure relief valve set at 2.3 psig.

The SCR systems will include an ammonia vaporization/injection skid where the ammonia will be vaporized prior to being injected upstream of the SCR catalyst system. Once the ammonia is injected, it will mix with the exhaust gases upstream of the SCR catalyst.

EMISSIONS CALCULATIONS

1. A/N 589935, 589936—Simple-Cycle Combustion Turbine Generators Nos. 1 and 2

The simple-cycle CTGs will emit combustion emissions consisting of criteria pollutants, toxic pollutants, and greenhouse gases. The two CTGs will have identical emissions. Emissions are based on manufacturer data and data from similar facilities.

A. Criteria Pollutants

Emissions calculations for CTGs are complex because emissions for four operational modes must be considered.

- **Worst Case Operating Scenarios**

To determine the worst case operating scenario that yields the highest controlled emissions, the applicant provided nine operating scenarios corresponding to a full range of possible turbine loads and ambient temperatures, which bound the expected normal operating range of each proposed CTG. The operating scenarios are for three load conditions (100%, 50%, and 20-21%) at three ambient temperatures (40 °F, 65 °F, and 102.7 °F), and with or without evaporative cooling of the inlet air to the turbines. The emissions rates correspond to the BACT levels for NO_x, CO, and VOC.

The operating scenarios data are summarized in the following table. The final revised data are from (1) *Table 5.1A-1 Rev. S3 Combustion Turbine Operating Emissions and Support Data*, and (2) *Table 5.1B-4 Facility Impact/Model Results Summary*, provided for the SERC Response Letter, 5/17/17. The SCAQMD added the PM_{2.5} emission rates, which are conservatively assumed to be equal to the PM₁₀ emission rates, as well as the long-term SO₂ emission rates. SERC Response Letter, 10/31/17, provided the net kW rating for each scenario.

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Table 7 –Turbine Operating Scenarios

Case No.	100	101	102	103	104	105	106	107	108
CTG Load Level (%)	100	50	21	100	50	21	100	50	20
CTG Inlet Air Cooling	On	Off	Off	On	Off	Off	Off	Off	Off
Ambient Conditions									
Ambient Temperature (°F)	102.7	102.7	102.7	65.0	65.0	65.0	40.0	40.0	40.0
Combustion Turbine Performance									
Gross GTG Output, kW (one CTG)	47,252	23,649	10,148	49,058	24,532	10,074	51,049	25,530	10,074
Net CTG Output, kW (one CTG)	45,891	22,549	9,048	47,673	23,432	8,974	49,637	24,430	8,974
CTG Heat Input, MMBtu/hr (LHV) (one CTG)	408.8	248.0	166.7	422.7	253.1	163.9	436.9	259.8	164.8
CTG Heat Input, MMBtu/hr (HHV) (one CTG)	453.1	274.9	184.7	468.5	280.5	181.6	484.2	287.9	182.6
Gross GTG Output, kW (project, two CTG)	94,504	47,298	20,296	98,116	49,064	20,148	102,098	54,060	20,148
Net CTG Output, kW (project, two CTG)	91,782	45,098	18,096	95,346	46,864	17,948	99,274	48,860	17,948
Stack Parameters									
Stack Exit Temperature, °F	847.69	816.23	813.37	839.13	751.91	721.22	826.85	701.10	662.16
Stack Diameter, ft	12.036	12.036	12.036	12.036	12.036	12.036	12.036	12.036	12.036
Stack Exit Velocity, ft/sec	87.203	63.497	48.479	88.902	64.500	48.367	90.814	65.713	48.672
CTG Outlet/Catalyst Inlet concentrations									
NOx, ppmvd (dry, 15% O ₂) / lb/hr as NO ₂	25 / 41.5	25 / 25.1	25 / 16.7	25 / 43	25 / 25.5	25 / 16.4	25 / 44.6	25 / 26.1	25 / 16.4
CO, ppmvd (dry, 15% O ₂) / lb/hr	7.3 / 7.4	14.1 / 8.6	12.6 / 5.1	11.2 / 11.7	18.1 / 11.2	15.0 / 6.0	32.9 / 35.7	37.4 / 23.8	30.6 / 12.2
VOC, ppmvd (dry, 15% O ₂) / lb/hr	2.3 / 1.3	2.3 / 0.8	2.3 / 0.5	2.3 / 1.4	2.3 / 0.8	2.3 / 0.5	3.7 / 2.3	4.3 / 1.6	3.4 / 0.8
Catalyst Outlet/Stack Emissions Rates									
NOx, 2.5 ppmvd (dry, 15% O ₂) BACT, lb/hr as NO ₂	4.15	2.51	1.67	4.30	2.55	1.63	4.46	2.61	1.64
CO, 4.0 ppmvd (dry, 15% O ₂) BACT, lb/hr	4.04	2.44	1.63	4.19	2.48	1.59	4.34	2.54	1.60
VOC, 2.0 ppmvd (dry, 15% O ₂) BACT, lb/hr	1.16	0.70	0.47	1.20	0.71	0.46	1.24	0.73	0.46
PM ₁₀ /PM _{2.5} , lb/hr (including ammonium sulfate) ¹	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
SO ₂ short-term rate (0.75 grains/100 scf), lb/hr ²	0.95	0.58	0.39	0.99	0.59	0.38	1.02	0.61	0.38
SO ₂ long-term rate (0.25 grains/100 scf), lb/hr	0.32	0.19	0.13	0.33	0.20	0.13	0.34	0.20	0.13
NH ₃ slip, 5.0 ppmvd (dry, 15% O ₂) BACT, lb/hr	3.07	1.85	1.24	3.18	1.89	1.21	3.30	1.93	1.21

¹ The sulfur in the natural gas fuel is converted to SO₂ and SO₃ in the turbine. A portion of the SO₂ in the turbine exhaust is assumed to oxidize to SO₃ in the CO catalyst. A portion of the total SO₃ is assumed to react with ammonia in the SCR to form ammonium sulfate particulates. The total PM₁₀/PM_{2.5} emissions are comprised of these ammonium sulfate particulates and the PM₁₀/PM_{2.5} in the turbine exhaust.

² Southern California Gas Company, Rule No. 30-Transportation of Customer-Owned Gas, allows up to 0.75 gr. S/100 scf total sulfur.

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Case 106, based on 100% load, 40 °F ambient temperature, and without inlet cooling, is the worst case operating scenario that yields the highest controlled emissions. The emissions rates for NO_x, CO, VOC, PM₁₀/PM_{2.5}, and the short-term SO₂ rate (0.75 grains/100 scf) will be used to calculate the normal operation emissions component for the maximum daily emissions and maximum monthly emissions. Since Case 106 is the scenario that yields the highest Btu/hr consumption for each turbine, it is also the basis for the turbine equipment description on the facility permit.

Case 103, based on 100% load, 65.0 °F ambient temperature, and with inlet cooling, is the worst case operating scenario that yields the highest emission rates for the average annual temperature. The emissions rates for NO_x, CO, VOC, PM₁₀/PM_{2.5}, and the long-term SO₂ rate (0.25 grains/100 scf) will be used to calculate the normal operation emissions component for maximum annual emissions. Condition B61.1 requires testing to confirm the long-term SO₂ rate of 0.25 grains/100 scf, which is expected to be the average content.

The air dispersion modeling and health risk assessment analyses discussed below also refer to the case numbers from the above table.

- **Four Operational Modes**

CTGs operate in four operational modes: commissioning, start-up, shutdown, and normal operation. The emissions from the four operating modes are estimated differently.

The following provides an explanation of the four operating modes, and the proposed parameters and emissions associated with each mode.

Commissioning

Commissioning is a one-time event that is performed after the installation of the turbines and associated equipment, and prior to commercial operation. The facility follows a systematic approach to optimize the performance of the CTGs and SCR/CO catalysts.

The NO_x, CO, and VOC emission rates are expected to be higher during the commissioning period than during normal operations, because the turbines are operated without, or with partial, emission control systems in operation. The total emissions, however, will depend on the load levels, which are less than 100% for some of the commissioning activities. The PM₁₀/PM_{2.5} and SO₂ emission rates are the same as during normal operation, because these pollutants are not controlled by the SCR/CO catalysts.

The Application provided the duration and corresponding pollutant emission rates (NO_x, CO, VOC, PM₁₀) for each commissioning activity for a CTG in *Table 5.1A-5 Commissioning Emissions* in *Appendix 5.1A Support Data for Emissions Calculations* of the Application. The PM₁₀ emission rates are based on the maximum hourly emission rate, 3.0 lb/hr (same for all cases). The Application proposed that the NO_x and CO CEMS be installed and operated prior to the commencement of commissioning activities to allow the

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NOx and CO emissions to be tracked for compliance with the proposed limits. In a letter dated 2/2/17, the SCAQMD explained that NOx and CO CEMs data may not be used for mass emissions reporting until certification testing has been successfully completed during normal operations. In a meeting on 2/8/16, the SCAQMD explained that, in lieu of using CEMS data, the SCAQMD will provide emission factors based on the information provided in *Table 5.1A-5*. SERC responded that they would review the table because the emissions for the commissioning activities are based on CEMS data from a similar facility in another air district. The SCAQMD requested supporting CEMS data to evaluate whether the proposed commissioning emissions can be used. In SERC Response Letter, 2/15/17, SERC provided revised *Table 5.1A-5*, now entitled *Table 5.1A-1 Rev. S2 Commissioning Emissions (per Turbine)*. The table provided the requested fuel usage for each commissioning activity, decreased the total VOC emissions for commissioning, and proposed two sets of emission factors (prior to catalyst installation and subsequent to catalyst installation). In a letter dated 2/24/17, the SCAQMD requested supporting CEMS data and information on the facility that is the source of the data, as well as the inclusion of SOx emissions per commissioning activity. In SERC Response Letter, 5/17/17, SERC provided supporting data and facility information, as well as *Table 5.1A-1 Rev. S3 Commissioning Emissions (per Turbine)*. The table provided the requested SOx emissions per activity, and decreased the total NOx, CO, and VOC emissions for the commissioning period.

The following table provides a summary of the commissioning activity parameters and emissions provided in *Table 5.1A-1 Rev. S3 Commissioning Emissions (per Turbine)*. The SCAQMD added the PM_{2.5} emission rates, which are conservatively assumed to be equal to the PM₁₀ emission rates.

SERC provided a comment letter, dated 2/20/18, on the PDOC. The letter included a revised Commissioning Emissions (per Turbine) table. The letter explained that previous versions of the table had inadvertently labeled step nos. 4 and 5 as pre-catalyst, but these steps are actually post-catalyst. Nevertheless, the pre-catalyst and post-catalyst emissions, fuel usage and emission factors are correct. (See *Table 21* below for derivation of the emission factors.) As a result, condition A63.1 will be revised to correct the descriptions of pre-catalyst phase and post-catalyst phase. Condition E193.3 will be revised to correct the uncontrolled commission hours limit from 38 hours to 20 hours.

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Table 8 - Turbine Commissioning Activity Parameters and Emissions (per Turbine)

Step No.	Description of Activity	Maximum Duration (hrs)	Average Fuel Use (MMBtu/Hr, HHV)	Total Fuel Use (MMBtu, HHV/ MMScf, HHV) ¹	Average Emissions Rates (lbs/hr)					Comments
					NOx	CO	VOC	PM ₁₀ /PM _{2.5}	SOx	
Steps 1-5 1-3: Pre-Catalyst Phase										
1	First fire and full speed, no load (not synchronized), no generator excitation	8	95.0		32.3	14.5	2.3	3.0	0.2	SCR and CO catalyst not installed, water injection not enabled
2	First fire and full speed, no load (not synchronized), generator excitation checks	6	95.0		32.3	14.5	2.3	3.0	0.2	SCR and CO catalyst not installed, water injection not enabled
3	First synchronization	6	95.0		32.3	14.5	2.3	3.0	0.2	SCR and CO catalyst not installed, water injection not enabled
Subtotal – Pre-Catalyst Phase										
Hours, Total Fuel Use, Total Pounds		38 20		1900/1.87	646	290	46	60	4	
Steps 6 4-6: Post-Catalyst										
4	Synchronization and ramp to full load, tuning water, ammonia (rough), and AVR (as needed), gas compressor tuning	10	156.2		24.1	3.3	1.24	3.0	0.3	SCR and CO catalyst not installed, water injection to be enabled and tuned
5	Full load operation with water injection and SPRINT in service for exhaust duct curing.	8	398.2		14.4	2.3	1.24	3.0	0.8	SCR and CO catalyst not installed, water injection operable
6	Full load operation with water injection and SPRINT in service and SCR/ammonia tuning	62	398.2		14.4	2.3	1.24	3.0	0.8	SCR and CO catalyst installed, testing of exhaust flow maldistribution and tuning of ammonia flows
Subtotal – Post-Catalyst Phase										
Hours, Total Fuel Use, Total Pounds		62 80		29,436/28.94	1,249	194	99	240	62	
Total Commissioning Period										
Hours, fuel usage, pounds		100		31,336/30.81	1,895	484	145	300	66	

¹ For total fuel use, MMBtu/hr is converted to MMscf/hr using 1017.2 Btu/scf from Table 5.1A-1 Rev. S3 Design Fuel Gas Analysis provided in the Application.

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The dispersion modeling analysis, discussed below, shows that the maximum impact would occur if both turbines were simultaneously undergoing commissioning activities with the highest unabated emissions. In *Table 37--Impacts during Commissioning-Total Project (Two Turbines)*, below, the modeled results demonstrate that both turbines may undergo simultaneous commissioning without causing the NO₂ or CO ambient standards to be exceeded.

Startup of Turbines

A startup event occurs each time a CTG is started up. A startup begins with the initiation of combustion, and concludes when BACT emissions levels are achieved or the startup is aborted by a trip. During start-up operations, the turbine operates at elevated average concentration rates for NO_x, CO, and VOC due to the phased-in effectiveness of the SCR and CO oxidation catalysts.

The beginning of startup occurs at initial fire in the combustor and the end of startup occurs when the BACT levels are achieved. The time from fuel initiation until reaching the baseload operating rate is expected to take up to 15 minutes.

For daily emissions, the Application ~~requested~~ assumed a maximum of six starts/shutdowns per turbine in the *Short-Term Emissions* table. Subsequently, the SERC Response Letter, 12/29/16 ~~requested~~ assumed a maximum of four starts/shutdowns in the revised *Short-Term Emissions* table.

For monthly emissions, the Application requested a maximum of 41 starts/shutdowns per turbine, equal to the requested annual maximum of 500 starts/shutdowns per turbine divided by 12 months. In a letter dated 12/2/16, the SCAQMD explained that for simple-cycle turbines, the average monthly emissions are not normally the maximum monthly emissions because the maximum monthly emissions occur in the summer months. Subsequently, the SERC Response Letter, 12/29/16, requested a maximum of 124 starts/shutdowns per month.

For annual emissions, the Applicant requested a maximum of 500 starts/shutdowns per turbine.

Shutdown of Turbines

A shutdown event occurs each time a CTG is shut down. A shutdown starts at the initiation of the turbine shutdown sequence and ends with the cessation of turbine firing. Typically, during the shutdown process, the emission rates will be less than during the start-up process but may be slightly higher than during normal operation. The ammonia injection into the SCR reactor will have ceased operation, but the SCR and CO catalysts remain at elevated temperatures and continue controlling for a portion of the shutdown.

The duration of a shutdown event is expected to take up to 10 minutes.

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As discussed above, the applicant ~~requested~~ assumed a maximum of four shutdowns per turbine for daily emissions, and requested a maximum of 124 shutdowns per turbine for monthly emissions, and a maximum of 500 shutdowns per turbine for annual emissions.

- **Startup/Shutdown Emissions**

In the Application, SERC provided two sets of startup and shutdown emissions per event for NO_x, CO, VOC, PM₁₀, and SO₂ in the *Startup & Shutdown Emissions Summary* table. The higher set of emissions was for “proposed limits,” and the lower set for “monthly and annual emissions calculations.” The proposed monthly and annual operating schedules were based on the lower set of startup and shutdown emissions.

In a letter dated 12/2/16, the SCAQMD explained emissions calculations are required to be based on maximum emissions rates, and requested maximum annual and monthly operating schedules based on maximum emissions rates. In SERC Response Letter, 12/29/16, SERC confirmed the “proposed limits” emissions are the maximum emissions rates for startups and shutdowns, and provided revised maximum annual and monthly operating schedules. As discussed below, the revised schedules also incorporated the required increase in normal operating emissions rates to maximum rates. In a meeting on 2/8/16, SERC explained the proposed startup and shutdown emissions are based on CEMS data from a similar facility in another air district. In SERC Response Letter, 2/15/17, SERC increased the emissions per startup for VOC. In a letter dated 2/24/17, the SCAQMD requested that SERC review the CEMS data from a similar facility to confirm the proposed startup emissions and duration, and shutdown emissions and duration for NO_x and CO, respectively, will be sufficient. In SERC Response Letter, 5/17/17, SERC provided *Table 5.1A-1 Rev. S3 Startup & Shutdown Emissions Summary*. The table corrected the startup emissions for NO_x, CO, VOC, PM₁₀, and SO_x, decreased the shutdown emissions for NO_x, CO, and VOC, and retained the same annual and monthly operating schedules with the same number of startups and shutdowns provided in the SERC letter, 12/29/16.

The following table summarizes the most recent startup emissions and duration, and shutdown emissions and duration, provided in *Table 5.1A-1 Rev. S3* for the SERC Response Letter, 5/17/17. The SCAQMD added the PM_{2.5} emission rates, which are conservatively assumed to be equal to the PM₁₀ emission rates, as well as the long-term SO₂ emission rates.

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Table 9 –Turbine Start-up/Shutdown Emission Rates

	Duration Minutes (hr)	NO _x lb/event	CO lb/event	VOC lb/event	PM ₁₀ (lb/event)	PM _{2.5} (lb/event)	SO _x (lb/event)
Startup	15 (0.25)	3.6	5.3	1.3	0.8	0.8	Short-term (0.75 grains/100 scf): 0.2 Long-term (0.25 grains/100 scf): 0.067
Shutdown	10 (0.167)	0.55	0.24	1.10	0.50	0.50	Short-term (0.75 grains/100 scf): 0.02 Long-term (0.25 grains/100 scf): 0.0067

- **Startup/Shutdown Conditions**

The startup and shutdown conditions limit and minimize emissions during startups and shutdowns when steady state BACT is not achievable. Condition C1.1 provides limits for startups, and condition C1.2 provides limits for shutdowns. The limits are necessary because conditions A195.1 and A195.2 state that steady state BACT for NO_x and CO, respectively, shall not apply during startups and shutdowns. In lieu of requiring steady state BACT at all times, an alternative BACT which limits and minimizes emissions during periods when steady state BACT is not achievable, such as during startups and shutdowns, has been accepted by EPA. The startup limits include: (1) number of starts per calendar month and year; (2) number of startups per day; and (3) duration of start; and (4) NO_x and CO emissions per start. The shutdown limits include: (1) number of shutdowns per calendar month and year; (2) number of shutdowns per day; (3) duration of shutdown; and (4) NO_x and CO emissions per shutdown. The NO_x and CO emissions limits for startups and shutdowns shall be confirmed by the NO_x CEMS and the CO CEMS, respectively.

For the purposes of these condition, the limits are for one turbine, except the annual limit is the combined total for two turbines (D1 and D7). As discussed under Rule 1303(b)(2)—Offsets, below, annual limits to stay under the Rule 1304(d)(1)(A) offset exemption thresholds are to be bubbled over all equipment that emit the specific air pollutants.

Normal Operation

Normal operation occurs after the CTGs and SCR/CO catalysts are working optimally. The emissions during normal operations are assumed to be fully controlled to BACT levels (2.5 ppmvd NO_x, 4.0 ppmvd CO, 2.0 ppmvd VOC), and exclude emissions due to commissioning, startup and shutdown periods, which are not subject to steady state BACT levels. As discussed above, BACT levels are not achievable during these periods.

The Application provided maximum annual emissions for the project in *Table 5.1-6 Combustion Turbine Emissions (Startup and Steady State Operation per Turbine)* and in *Table 5.1A-1 Maximum Annual & Monthly Emissions – Normal Year*. The annual emissions for NO_x, PM₁₀, and VOC were erroneously based on emission rates that were less than the BACT rates shown in *Table 7—Turbine Operating Scenarios*. The maximum monthly emissions were derived by dividing the maximum annual emissions by 12 months.

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In a letter dated 12/2/16, the SCAQMD explained emissions calculations are required to be based on maximum emissions rates. In a letter dated 12/29/16, SERC increased the NOx and PM₁₀ emission rates to BACT levels. In SERC Response Letter, 2/15/17, SERC increased the VOC emission rate to the BACT level.

- **Maximum Daily, Monthly, Annual Emissions**

This section will derive maximum daily emissions, maximum monthly emissions, maximum annual emissions, and thirty-day average emissions. The next section will discuss permit conditions to limit maximum commissioning emissions (component of monthly and annual emissions), maximum monthly emissions, and maximum annual emissions, including the derivation of emissions factors for the conditions.

Maximum Daily Emissions per Turbine

Maximum daily emissions during normal operations are calculated to determine whether BACT is required. The BACT analysis under Rule 1303(a)—BACT, below, explains that the applicability threshold is an increase of 1 lb/day of uncontrolled emissions. For BACT determination, the maximum daily emissions are based on realistic maximum daily emissions, not the 30-day average emissions calculated for offset determination.

Commissioning Month

Maximum daily emissions for the commissioning month are not necessary to be determined because commissioning will take place once during the life of the turbines.

Normal Operating Month

The SERC Response Letter, 12/29/16, ~~requested~~ assumed a maximum of four starts/shutdowns in the revised *Short-Term Emissions* table. The normal operation emission rates are from *Table 7—Turbine Operating Scenarios* (case 106), above. The startup and shutdown emissions per event are from *Table 9—Turbine Start-up/Shutdown Emission Rates*, above. The SOx emission rates based on the short-term rate (0.75 grains/100 scf).

For BACT applicability, the increases in daily emissions are based on uncontrolled emissions. For each turbine, however, the increases in daily emissions based on either uncontrolled or controlled emissions indicate BACT is required. The maximum controlled daily emissions for normal operation are more informative and, as such, are shown in the table below.

Table 10 - Maximum Daily Emissions per Turbine

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shut downs	lb/shutdown	Maximum Daily Emissions, lb/day
NOx	22.32	4.46	4	3.6	4	0.55	116.15
CO	22.32	4.34	4	5.3	4	0.24	119.03
VOC	22.32	1.24	4	1.3	4	1.10	37.28
PM ₁₀ /PM _{2.5}	22.32	3.0	4	0.8	4	0.50	72.16
SOx	22.32	1.02	4	0.2	4	0.02	23.65

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No. of normal operating hours = 24 hr/day – (4 startups/day)(0.25 hr/start) - (4 shutdowns/day)
(0.17 hr/shutdown) = 22.32 hr

Maximum Daily Emissions, lb/day = (no. normal operating hours) (normal emission rate, case 106)
+ (no. startups) (lb/startup) + (no. shutdowns) (lb/shutdown)

Maximum Monthly Emissions per Turbine

Condition A63.1 will specify the monthly emissions limits for NO_x, CO, VOC, PM₁₀, PM_{2.5}, and SO_x per turbine. Monthly limits are required to ensure compliance with BACT and Rule 1313(g). These requirements are discussed under the regulatory analysis section below. For a month during which both commissioning and normal operation take place, the monthly emissions are the sum of the commissioning emissions and the normal operating emissions.

In the Application, SERC provided maximum monthly emissions, derived by dividing the maximum annual emissions by twelve months. In a letter dated 12/2/16, the SCAQMD explained the maximum monthly emissions for each pollutant are based on the highest emissions of any month, including commissioning month(s), combination commissioning/normal operating month, and normal operating month. In SERC Response Letter, 12/29/16, SERC responded the commissioning for each turbine is anticipated to be completed during a 30-day month, which could include some hours of normal operation.

In SERC Response Letter, 5/17/17, SERC provided *Table 5.1A-1 Rev. S3--Maximum Annual & Monthly Emissions – Normal Year*, which incorporated the most recent revised maximum emission rates. This table presents three normal operating month profiles (case nos. 1 – 3), and a profile in which both commissioning and normal operations take place (case no. “Commission”). Emissions calculations are shown below for each profile. The maximum monthly emissions limits for NO_x, CO, VOC, PM₁₀, PM_{2.5}, and SO_x will be based on the highest emissions for any month. As shown below, the operating profile for a month in which both commissioning and normal operations take place (case no. “Commission”) did not result in the highest emissions for any pollutants.

The commissioning emissions are from *Table 8—Turbine Commissioning Activity Parameters*, above. The normal operation emission rates are from *Table 7—Turbine Operating Scenarios* (case 106), above, and the startup and shutdown emissions per event are from *Table 9—Turbine Start-up/Shutdown Emission Rates*, above. For all three, the SO_x emission rates are based on the short-term rate (0.75 grains/100 scf).

- **“Case No. 1” Monthly Emissions Operating Profile**

The monthly emissions for the first operating profile (744 total hours, consisting of 692 normal operating hours and 124 startups/shutdowns) are calculated in the table below.

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Table 11—Case No. 1 Monthly Emissions per Turbine

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shut downs	lb/shutdown	Monthly Emissions lb/month (tons/month)
NOx	692	4.46	124	3.6	124	0.55	3,600.92 (1.8)
CO	692	4.34	124	5.3	124	0.24	3,690.24 (1.85)
VOC	692	1.24	124	1.3	124	1.10	1,155.68 (0.58)
PM ₁₀ /PM _{2.5}	692	3.0	124	0.8	124	0.50	2237.20 (1.12)
SOx	692	1.02	124	0.2	124	0.02	733.12 (0.37)

Monthly Emissions, lb/month = (no. normal operating hours) (normal emission rate, case 106)
+ (no. startups) (lb/startup) + (no. shutdowns) (lb/shutdown)

- “Case No. 2” Monthly Emissions Operating Profile

The monthly emissions for the second operating profile (70 total hours, consisting of 67 normal operating hours and 8 startups/shutdowns) are calculated in the table below.

Table 12—Case No. 2 Monthly Emissions per Turbine

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shut downs	lb/shutdown	Monthly Emissions lb/month (tons/month)
NOx	67	4.46	8	3.6	8	0.55	332.02 (0.17)
CO	67	4.34	8	5.3	8	0.24	335.10 (0.17)
VOC	67	1.24	8	1.3	8	1.10	102.28 (0.05)
PM ₁₀ /PM _{2.5}	67	3.0	8	0.8	8	0.50	211.40 (0.11)
SOx	67	1.02	8	0.2	8	0.02	70.10 (0.04)

- “Case No. 3” Monthly Emissions Operating Profile

The monthly emissions from the third operating profile (743 total hours, consisting of 742.58 normal operating hours and 1 startups/shutdowns), are calculated in the table below.

Table 13—Case No. 3 Monthly Emissions per Turbine

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shut downs	lb/shutdown	Monthly Emissions lb/month (tons/month)
NOx	742.58	4.46	1	3.6	1	0.55	3316.06 (1.66)
CO	742.58	4.34	1	5.3	1	0.24	3228.34 (1.61)
VOC	742.58	1.24	1	1.3	1	1.10	923.20 (0.46)
PM ₁₀ /PM _{2.5}	742.58	3.0	1	0.8	1	0.50	2229.04 (1.11)
SOx	742.58	1.02	1	0.2	1	0.02	757.65 (0.38)

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- “Case No. Commission” Monthly Emissions Operating Profile

For a month during which both commissioning and normal operation take place, the monthly emissions are the sum of the commissioning emissions and the normal operating emissions. The monthly emissions from the commissioning and normal operations operating profile (100 hours for commissioning, and 450 total normal operating hours, consisting of 340 normal operating hours and 23 startups/shutdowns), are calculated as follows.

Commissioning Emissions Component—The total commissioning period emissions for the 100 hours are from *Table 8—Turbine Commissioning Activity Parameters and Emissions*, above.

Normal Operating Emissions Component—The emissions calculations for 450 total normal operating hours, consisting of 340 normal operating hours, and 23 startups/shutdowns, are shown in the table below.

Table 14—“Case No. Commission”—Normal Operating Component of Monthly Emissions per Turbine

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shut downs	lb/shutdown	Monthly Emissions lb/month (tons/month)
NO _x	340	4.46	23	3.6	23	0.55	1611.85 (0.81)
CO	340	4.34	23	5.3	23	0.24	1603.02 (0.80)
VOC	340	1.24	23	1.3	23	1.10	476.80 (0.24)
PM ₁₀ /PM _{2.5}	340	3.0	23	0.8	23	0.50	1049.90 (0.52)
SO _x	340	1.02	23	0.2	23	0.02	351.86 (0.18)

Total “Case No. Commission” Monthly Emissions—The emissions calculations to add the commissioning emissions and normal operating emissions are shown in the table below.

Table 15—“Case No. Commission”—Total Monthly Emissions per Turbine

Pollutants	Commissioning Emissions, lb/month (<i>Table 8</i>)	Normal Operating Emissions, lb/month (<i>Table 14</i>)	Monthly Emissions lb/month (tons/month)
NO _x	1895	1611.85	3506.85 (1.75)
CO	484	1603.02	2087.20 (1.04)
VOC	145	476.80	621.80 (0.31)
PM ₁₀ /PM _{2.5}	300	1049.90	1349.90 (0.67)
SO _x	66	351.86	417.86 (0.21)

Maximum Monthly Emissions, lb/month = Commissioning Emissions + Normal Operating Emissions

- Maximum Monthly Emissions per Turbine

The maximum monthly emissions limits for NO_x, CO, VOC, PM₁₀, PM_{2.5}, and SO_x will be based on the highest emissions for any month. The table below compares the emissions from the four monthly operating profiles, with the highest values shown in bold font.

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Table 16—Maximum Monthly Emissions per Turbine and Total Project (Two Turbines)

Pollutants	Case No. 1	Case No. 2	Case No. 3	Case No. “Commissioning”	Maximum Monthly Emissions lb/month (tons/month) per Turbine	Maximum Monthly Emissions lb/month (tons/month) per Two Turbines
Total Hours	744	70	743	100 - Commissioning 450 - Normal Operation		
NO _x	3,600.92	332.02	3316.06	3506.85	3,600.92 (1.8)	7201.84 (3.6)
CO	3,690.24	335.10	3228.34	2087.20	3,690.24 (1.85)	7380.48 (3.70)
VOC	1,155.68	102.28	923.20	621.80	1,155.68 (0.58)	2311.36 (1.16)
PM ₁₀ /PM _{2.5}	2237.20	211.40	2229.04	1349.90	2237.20 (1.12)	4474.40 (2.24)
SO _x	733.12	70.10	757.65	417.86	757.65 (0.38)	1515.30 (0.76)

Maximum Annual Emissions and 30-Day Average Emissions per Turbine

As the monthly emissions limits in condition A63.1 are applicable each and every month, the annual emissions limits are the monthly emissions multiplied by twelve months, unless the annual emissions are limited by permit condition. SERC has requested annual emissions limits.

Condition A63.2 will specify the annual emission limits for NO_x, CO, VOC, PM₁₀, PM_{2.5}, and SO_x, based on the total combined emissions from both turbines (D1 and D7). As discussed under Rule 1303(b)(2)—Offsets, below, annual limits to stay under the Rule 1304(d)(1)(A) offset exemption thresholds are to be bubbled over all equipment that emit the specific air pollutants. In addition to determining offsets exemption applicability, annual limits ensure compliance with BACT requirements, ensure compliance with air quality modeling and health risk assessment requirements, and determine RECLAIM applicability. These requirements are discussed under the regulatory analysis section below.

In SERC Response Letter, 5/17/17, SERC provided *Table 5.1A-1 Rev. S3--Maximum Annual & Monthly Emissions – Normal Year*, which incorporated the most recent revised maximum emission rates. This table presents three annual operating profiles (case nos. 1 – 3). Emissions calculations are shown below for each profile. The maximum annual emissions limits for NO_x, CO, VOC, PM₁₀, PM_{2.5}, and SO_x will be based on the highest emissions for any of the three annual operating profiles provided by SERC for this purpose. SERC has indicated the annual emissions during the commissioning year will not exceed emissions during a non-commissioning year.

The normal operation emission rates are from *Table 7—Turbine Operating Scenarios* (case 103), above, and the startup and shutdown emissions per event are from *Table 9—Turbine Start-up/Shutdown Emission Rates*, above. The SO_x emission rates are based on the long-term rate (0.25 grains/100 scf).

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- “Case No. 1” Annual Emissions Operating Profile
The maximum annual emissions from the first operating profile (638 total hours, consisting of 430 normal operating hours, and 500 startups/shutdowns).

Table 17—Case No. 1 Annual Emissions per Turbine

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shut downs	lb/shutdown	Annual Emissions lb/yr (tons/yr)
NO _x	430	4.30	500	3.6	500	0.55	3,924.00 (1.96)
CO	430	4.19	500	5.3	500	0.24	4,571.70 (2.29)
VOC	430	1.20	500	1.3	500	1.10	1,716.00 (0.86)
PM ₁₀ /PM _{2.5}	430	3.0	500	0.8	500	0.50	1,940.00 (0.97)
SO _x	430	0.33	500	0.067	500	0.0067	178.75 (0.089)

Annual Emissions, lb/yr = (no. normal operating hours) (normal emission rate, Case 103) + (no. startups) (lb/startup) + (no. shutdowns) (lb/shutdown)

- “Case No. 2” Annual Emissions Operating Profile
The maximum annual emissions from the second operating profile (850 total hours, consisting of 808 normal operating hours, and 100 startups/shutdowns), are shown below.

Table 18—Case No. 2 Annual Emissions per Turbine

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shut downs	lb/shutdown	Annual Emissions lb/yr (tons/yr)
NO _x	808	4.30	100	3.6	100	0.55	3889.40 (1.94)
CO	808	4.19	100	5.3	100	0.24	3939.52 (1.97)
VOC	808	1.20	100	1.3	100	1.10	1209.60 (0.60)
PM ₁₀ /PM _{2.5}	808	3.0	100	0.8	100	0.50	2554.00 (1.28)
SO _x	808	0.33	100	0.067	100	0.0067	274.01 (0.14)

- “Case No. 3” Annual Emissions Operating Profile
The maximum annual emissions from the third operating profile (902 total hours, consisting of 901.58 normal operating hours, and 1 startup/shutdown), are shown below.

Table 19—Case No. 3 Annual Emissions per Turbine

Pollutants	No. of Normal Operating Hours	Normal Operation Emission Rate, lb/hr	No. of Startups	lb/startup	No. of Shut downs	lb/shutdown	Annual Emissions lb/yr (tons/yr)
NO _x	901.58	4.30	1	3.6	1	0.55	3,880.94 (1.94)
CO	901.58	4.19	1	5.3	1	0.24	3,783.16 (1.89)
VOC	901.58	1.20	1	1.3	1	1.10	1,084.30 (0.54)
PM ₁₀ /PM _{2.5}	901.58	3.0	1	0.8	1	0.50	2,706.04 (1.35)
SO _x	901.58	0.33	1	0.067	1	0.0067	297.60 (0.15)

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- Maximum Annual Emissions and 30-Day Average Emissions per Turbine**
 The maximum annual emissions limits for NO_x, CO, VOC, PM₁₀, PM_{2.5}, and SO_x will be based on the highest emissions of any month. The table below compares the emissions from the three annual operating profiles, with the highest values shown in bold font. In addition, the table below shows the 30-day average emissions for each pollutant. The 30-day average for each pollutant is calculated by dividing the maximum annual emissions by 12 months, then by 30 days.

Table 20—Maximum Annual Emissions per Turbine and Total Project (Two Turbines) and 30-Day Averages per Turbine

Pollutants	Case No. 1	Case No. 2	Case No. 3	Maximum Annual Emissions lb/yr (tons/yr) per Turbine	30-Day Averages per Turbine (lb/day)	Maximum Annual Emissions lb/yr (tons/yr) per Two Turbines
Total Hours	638	850	902 -- Maximum total hours			
NO _x	3,924.00 (1.96)	3889.40 (1.94)	3,880.94 (1.94)	3,924.00 (1.96)	10.90	7848.00 (3.92)
CO	4,571.70 (2.29)	3939.52 (1.97)	3,783.16 (1.89)	4,571.70 (2.29)	12.70	9143.40 (4.58)
VOC	1,716.00 (0.86)	1209.60 (0.60)	1,084.30 (0.54)	1,716.00 (0.86)	4.77	3432.00 (1.72)
PM ₁₀ /PM _{2.5}	1,940.00 (0.97)	2554.00 (1.28)	2,706.04 (1.35)	2,706.04 (1.35)	7.52	5412.08 (2.70)
SO _x	178.75 (0.089)	274.01 (0.14)	297.60 (0.15)	297.60 (0.15)	0.83	595.20 (0.30)

- Permit Conditions to Limit Maximum Commissioning Emissions, Monthly Emissions and Annual Emissions**

This section will discuss permit conditions to limit maximum commissioning emissions (component of monthly and annual emissions), maximum monthly emissions, and maximum annual emissions, including the derivation of emissions factors for the conditions.

Maximum Commissioning Emissions Condition

The NO_x, CO, and VOC emission rates are expected to be higher during the commissioning period than during normal operations, because the turbines are operated without, or with partial emission control systems in operation.

Condition E193.3 will require that the total commissioning hours shall not exceed 100 hours of fired operation for each turbine from the date of initial turbine start-up in order to minimize emissions during the commissioning period when steady state BACT is not achievable. Of the 100 hours, commissioning hours without control (pre-catalyst phase as defined in condition A63.1) shall not exceed ~~38~~ 20 hours. The total commissioning hours

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and the hours without control were requested by SERC, as summarized in *Table 8--Turbine Commissioning Activity Parameters and Emissions*, above.

The commissioning period emissions will be limited by the maximum monthly emissions limits in condition A63.1, as well as the maximum annual emissions limits (based on a 12-operating month-rolling average basis) in condition A63.2. Condition A63.1 will require a Method 100.1 source test van CEMS to measure the NOx emissions for the entire commissioning period. This option was selected by SERC in the SERC Response Letter, 10/31/17, in lieu of using commissioning emission factor(s) for NOx derived from data provided by General Electric. In addition, the condition will set forth emission factors for the commissioning period for CO, VOC, PM₁₀/PM_{2.5}, and SOx. SERC requested separate emission factors for the commissioning period prior to installation of the catalysts (pre-catalyst phase) and for the commissioning period subsequent to installation of the catalysts (post-catalyst phase). For CO, VOC, PM₁₀/PM_{2.5}, and SOx, the emission factors are calculated as the total emissions for the phase divided by the total fuel usage for the phase, from *Table 8*. The emission factors for the pre-catalyst phase and the post-catalyst phase are calculated in the table below.

**Table 21 - Turbine Commissioning Emission Factors,
Pre-Catalyst Phase and Post-Catalyst Phase**

Pollutant	Total Emissions, lb	Total Fuel Usage, mmcf	Emission Factor, lb/mmcf
Pre-Catalyst Phase (Steps 1—5 1 - 3)			
NOx	646	1.87	345.45
NOx will be measured with an SCAQMD Method 100.1 source test van CEMS, instead of determined through the use of the above emission factor, for added accuracy.			
CO	290	1.87	155.08
VOC	46	1.87	24.60
PM ₁₀ /PM _{2.5}	60	1.87	32.09
SOx	4	1.87	2.14
Post-Catalyst Phase (Steps 6 4 - 5)			
NOx	1,249	28.94	43.16
NOx will be measured with an SCAQMD Method 100.1 source test van CEMS, instead of determined through the use of the above emission factor, for added accuracy.			
CO	194	28.94	6.70
VOC	99	28.94	3.42
PM ₁₀ /PM _{2.5}	240	28.94	8.29
SOx	62	28.94	2.14

Emission factor, lb/mmcf = (lb/phase) (phase/mmcf)

For the pre-catalyst phase, the emission factors will be 155.08 lb/mmcf CO, 24.60 lb/mmcf VOC, 32.09 lb/mmcf PM₁₀/PM_{2.5}, and 2.14 lb/mmcf SOx. For the post-catalyst phase, the

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emission factors will be 6.70 lb/mmcf CO, 3.42 lb/mmcf VOC, 8.29 lb/mmcf PM₁₀/PM_{2.5}, and 2.14 lb/mmcf SO_x.

For the commissioning period (pre-catalyst and post-catalyst phases), NO_x emissions will be measured with an SCAQMD Method 100.1 source test van CEMS.

Maximum Monthly Emissions Conditions

Condition A63.1 will specify the monthly emissions limits for NO_x, CO, VOC, PM₁₀, PM_{2.5}, and SO_x. Monthly limits are required to ensure compliance with BACT and Rule 1313(g).

For a month during which both commissioning and normal operation take place, the monthly emissions are the sum of the commissioning emissions and the normal operating emissions. The procedure for determining the commissioning emissions, emission factors for CO, VOC, PM₁₀/PM_{2.5}, and SO_x, and CEMS for NO_x, is described above.

The emission factors for the normal operating emissions are calculated in the table below. For each pollutant, the emission factor is calculated as the maximum monthly emissions per turbine divided by the maximum monthly fuel usage. The maximum monthly emissions are from *Table 16—Maximum Monthly Emissions per Turbine and Total Project (Two Turbines)*, above. As *Table 16* shows that the maximum monthly emissions for NO_x, CO, VOC, and PM₁₀/PM_{2.5} are from the Case No. 1 operating profile, the maximum monthly fuel usage will be based on 744 total hours. For total fuel use, MMBtu/hr is converted to Mmscf/hr using 1017.2 Btu/scf from *Table 5.1A-1 Rev. S3 Design Fuel Gas Analysis* provided in the Application.

Table 22 - Turbine Normal Operating Emission Factors for Monthly Emissions

Pollutants	Maximum Monthly Emissions, lb/month	Emission Factors, lb/mmcf
NO _x	3,600.92	10.17
CO	3,690.24	10.42
VOC	1,155.68	3.26
PM ₁₀ /PM _{2.5}	2237.20	6.32
SO _x	757.65	2.14

Emission factor, lb/mmcf = (lb/month) (month/354.15 mmscf)

where max monthly fuel usage = (744 hours, incl. startups/shutdowns)
(484.2 MMBtu/hr, Case 106) (mmscf/1017.2 MMBtu) = 354.15 mmscf/month

From the table above, condition A63.1 will limit the maximum monthly emissions, comprised of commissioning emissions and normal operating emissions, to 3601 lb/month NO_x, 3690 lb/month CO, 1156 lb/month VOC, 2237 lb/month PM₁₀, 2237 lb/month PM_{2.5}, and 758 lb/month SO_x.

The normal operating emission factors for VOC, PM₁₀/PM_{2.5}, and SO_x will be 3.26 lb/mmcf VOC, 6.32 lb/mmcf PM₁₀/PM_{2.5}, and 2.14 lb/mmcf SO_x. The NO_x and CO emission shall

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be measured with certified NO_x CEMS and CO CEMS, respectively. For the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the NO_x and CO are assumed to be operating at BACT levels. The emission factors are as follows: NO_x, 10.17 lb/mmcf; CO, 10.42 lb/mmcf.

Maximum Annual Emissions Conditions

Condition A63.2 will specify the annual emissions limits for NO_x, CO, VOC, PM₁₀, PM_{2.5}, and SO_x. Annual limits are required to determine offsets exemption applicability, ensure compliance with BACT requirements, ensure compliance with air quality modeling and health risk assessment requirements, and determine RECLAIM applicability. For the modeling, the annual limits for PM₁₀/PM_{2.5} and NO_x emissions will ensure that the modeled emission rates for these pollutants for the annual averaging period in *Table 33--Modeled Emission Rates - Normal Operation*, below, will not be exceeded. For the health risk assessment, the annual limits for the criteria pollutants establish the maximum annual fuel usage, which will ensure that the annual toxic air contaminants in *Table 24—Toxic Air Contaminants/Hazardous Air Pollutants per Turbine*, below, will not be exceeded.

For a year during which both commissioning and normal operation take place, the annual emissions are the sum of the commissioning emissions and the normal operating emissions. The procedure for determining the commissioning emissions, emission factors for CO, VOC, PM₁₀/PM_{2.5}, and SO_x, and CEMS for NO_x, is described above for condition A63.1.

Table 27--Facility Maximum Annual Emissions, below, shows that the NO_x, CO, VOC, PM₁₀, PM_{2.5}, and SO_x emissions are from the two turbines only. *Table 20--Maximum Annual Emissions per Turbine and Total Project (Two Turbines) and 30-Day Averages per Turbine*, above, provides the annual emissions for one turbine and two turbines, respectively. Condition A63.2 will limit the maximum annual emissions, comprised of commissioning emissions and normal operating emissions, based on the total combined emissions from both turbines (D1 and D7), to 7848 lb/yr NO_x, 9143 lb/yr CO, 3432 lb/yr VOC, 5412 lb/yr PM₁₀, 5412 lb/yr PM_{2.5}, and 595 lb/yr SO_x. As explained under the regulatory analysis for Rule 1303(b)(2)—Offsets, below, annual limits to stay under the Rule 1304(d)(1)(A) offset exemption thresholds are to be bubbled over all equipment that emit the specific air pollutants.

The emission factors for the monthly emission limits shall be used to demonstrate compliance with the annual emission limits, except for SO_x. The annual SO_x emission factor is lower than the monthly SO_x emissions factor, because the annual emissions will be based on 0.25 grains/100 scf but the monthly emissions on 0.75 grains/100 scf.

For SO_x, the emission factor is calculated as the maximum annual emissions per turbine divided by the maximum annual fuel usage from *Table 20—Maximum Annual Emissions per Turbine and Total Project (Two Turbines) and 30-Day Averages per Turbine*, above.

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The annual SOx emission factor is calculated below.

Table 23 - Turbine Normal Operating Emission Factor for SOx - Annual Limit

Pollutants	Maximum Annual Emissions, lb/year	Emission Factors, lb/mmcf
SOx	298	0.72

Emission factor, lb/mmcf = (lb/yr) (yr / 415.44 mmscf)

Where max annual fuel usage = (902 hours, incl. startups/shutdowns)
(468.5 MMBtu/hr, Case 103) (mmscf/1017.2 MMBtu) = 415.44 mmscf/yr

- **Continuous Emissions Monitoring Conditions**

This section will discuss permit conditions for the CO CEMS and the NOx CEMS to ensure compliance with BACT and offset requirements.

CO CEMS, Condition D82.1

Each turbine will be equipped with an oxidation catalyst to control CO emissions. A CO CEMS is required on each turbine to ensure compliance with BACT requirements pursuant to Rule 1303(a)(1). The CO CEMS will demonstrate compliance with the CO BACT limit of 4.0 ppmvd at 15% O₂, required by condition A195.2. In addition, the CO CEMS will demonstrate compliance with the monthly and annual emissions limits in conditions A63.1 and A63.2, respectively, to ensure compliance with BACT requirements. Further, the CO CEMS will demonstrate compliance with the start-up and shut-down durations and emission limits set forth in conditions C1.1 and C1.2, respectively, to minimize CO emissions for startups and shutdowns during which steady state BACT is not achievable.

The CO CEMS requirements to ensure compliance with BACT requirements will be set forth in condition D82.1. The condition will require the CO CEMS to be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved SCAQMD Rule 218 CEMS plan application. The CO CEMS will measure the concentration in ppmv, correct the concentration to 15 percent oxygen on a dry basis, and measure concentrations over a 15 minute averaging time period. The CEMS will convert the actual concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.

The initial certification testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the operator shall use the CO emission factor provided in condition A63.1 for these purposes.

The CO CEMS is subject to Rules 218 and 218.1. See regulatory analysis for these rules for additional information.

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NOx CEMS, Condition D82.2

Each turbine will be equipped with an SCR to control NOx emissions. A NOx CEMS is required on each turbine to ensure compliance with BACT requirements pursuant to Rule 1303(a)(1), offset requirements pursuant to Rule 1303(a)(2), and modeling requirements pursuant to Rule 1303(b)(1). The NOx CEMS will demonstrate compliance with the NOx BACT limit of 2.5 ppmvd at 15% O₂, required by condition A195.1. In addition, the NOx CEMS will demonstrate compliance with the monthly and annual emissions limits in conditions A63.1 and A63.2, respectively, to ensure compliance with BACT and offset requirements. Further, the NOx CEMS will demonstrate compliance with the start-up and shut-down durations and emission limits set forth in conditions C1.1 and C1.2, respectively, to minimize NOx emissions for startups and shutdowns during which steady state BACT is not achievable.

The NOx CEMS requirements to ensure compliance with BACT and offset requirements will be set forth in condition D82.2. The condition will require the NOx CEMS to be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved CEMS certification application submitted in compliance with 40 CFR Part 60 Subpart KKKK and 40 CFR Part 75. The NOx CEMS will measure the concentration in ppmv, correct the concentration to 15 percent oxygen on a dry basis, and measure concentrations over a 15 minute averaging time period. (Note: For condition D82.1, the 15 minute averaging period for a Rule 218 CO CEMS is standard for power plants. For condition D82.2, the Source Test Engineering Dept. confirmed the 15 minute averaging period is appropriate for a Subpart KKKK and Part 75 NOx CEMS.) The CEMS will convert the actual concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.

The condition will require the initial certification testing shall be completed and submitted to the SCAQMD within 90 days of the conclusion of the turbine commissioning period. During the interim period between the conclusion of the commissioning period and the provisional certification date of the CEMS, and in the event of CEMS failure subsequent to CEMS certification, the operator shall use the emission factor for NOx provided in condition A63.1 for these purposes.

The NOx CEMS will also demonstrate compliance with the 25 ppmv at 15% O₂ per 40 CFR Part 60 Subpart KKKK (condition H23.1), as well as monitor NOx emissions per 40 CFR Part 75 (condition H23.2). The NOx CEMS will not be subject to Rule 218, because Rule 218(b)(1)(A) specifies that the rule shall not apply to any CEMS subject to Source Performance Standards (NSPS) or Regulation XXXI—Acid Rain Program. The NOx CEMS will be subject to the CEMS requirements of Subpart KKKK and Part 75. Conditions H23.1 and H23.2 are discussed under the regulatory analysis for 40 CFR Part 60 Subpart KKKK and 40 CFR Part 75, respectively.

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- **New Source Review (NSR) Database Entries**

This section develops the internal NSR Data Summary Sheet entries.

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

The 30-day averages per turbine are from *Table 20—Maximum Annual Emissions per Turbine and Total Project (Two Turbines) and 30-Day Averages per Turbine*, above. The uncontrolled emissions (R1) and controlled emissions (R2) are back calculated from the 30-day averages for the purpose of input into the internal NSR Data Summary Sheet only.

NO_x

$$R2 = (10.90 \text{ lb/day})(\text{day}/24 \text{ hr}) = 0.45 \text{ lb/hr}$$

$$R1 = (0.45 \text{ lb/hr})(25 \text{ ppm uncontrolled}/2.5 \text{ ppm per Case 103}) = 4.50 \text{ lb/hr}$$

$$30\text{-DA} = 10.90 \text{ lb/day}$$

CO

$$R2 = (12.70 \text{ lb/day})(\text{day}/24 \text{ hr}) = 0.53 \text{ lb/hr}$$

$$R1 = (0.53 \text{ lb/hr})(11.2 \text{ ppm uncontrolled}/4 \text{ ppm controlled per case 103}) = 1.48 \text{ lb/hr}$$

$$30\text{-DA} = 12.70 \text{ lb/day}$$

ROG

$$R2 = (4.77 \text{ lb/day})(\text{day}/24 \text{ hr}) = 0.20 \text{ lb/hr}$$

$$R1 = (0.20 \text{ lb/hr})(2.3 \text{ ppm uncontrolled}/2 \text{ ppm controlled per case 103}) = 0.23 \text{ lb/hr}$$

$$30\text{-DA} = 4.77 \text{ lb/day}$$

PM₁₀

$$R2 = R1 = (7.25 \text{ lb/day})(\text{day}/24 \text{ hr}) = 0.30 \text{ lb/hr}$$

$$30\text{-DA} = 7.25 \text{ lb/day}$$

SO_x

$$R2 = R1 = (0.83 \text{ lb/day})(\text{day}/24 \text{ hr}) = 0.03 \text{ lb/hr}$$

$$30\text{-DA} = 0.83 \text{ lb/day}$$

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B. Greenhouse Gases (GHG)

- Turbine Combustion: CO₂, CH₄, N₂O

Combustion of natural gas in the turbines will result in emissions of CO₂, CH₄, and N₂O.

Using the same basis as for the determination of the SO_x emission factor for *Table 23 - Turbine Normal Operating Emission Factor for SO_x - Annual Limit*:

$$(902 \text{ hours, incl. startups/shutdowns})(468.5 \text{ MMBtu/hr, Case 103}) = 422,587.0 \text{ MMBtu/yr}$$

Emission factors for CO₂, CH₄, and N₂O are from the US EPA website, Emission Factors for Greenhouse Gas Inventories, Table 1—Stationary Combustion Emission Factors, revised April 4, 2014. (See table at https://www.epa.gov/sites/production/files/2015-07/documents/emission-factors_2014.pdf)

For each turbine:

CO₂: 53.06 kg CO₂/MMBtu

CH₄: 1 g CH₄/MMBtu

N₂O: 0.10 g N₂O/MMBtu

$$\begin{aligned} \text{CO}_2 &= (422,587.0 \text{ MMBtu/yr})(53.06 \text{ kg/MMBtu})(2.2046 \text{ lb/kg}) \\ &= 49,432,569.03 \text{ lb/yr} = 24,716.28 \text{ tpy} \end{aligned}$$

$$\begin{aligned} \text{CH}_4 &= (422,587.0 \text{ MMBtu/yr})(1 \text{ g/MMBtu})(2.205 \times 10^{-3} \text{ lb/g}) \\ &= 931.80 \text{ lb/yr} = 0.47 \text{ tpy} \end{aligned}$$

$$\begin{aligned} \text{N}_2\text{O} &= (422,587.0 \text{ MMBtu/yr})(0.1 \text{ g/MMBtu})(2.205 \times 10^{-3} \text{ lb/g}) \\ &= 93.18 \text{ lb/yr} = 0.047 \text{ tpy} \end{aligned}$$

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) CH₄ is equivalent to 25 times the global warming potential of CO₂, and (2) N₂O is equivalent to 298 times of CO₂. (See table at https://www.ecfr.gov/cgi-bin/text-idx?SID=9df2d28baf52a7d89ffa94ef843b1b0&mc=true&node=ap40.23.98_19.1&rgn=div9)

$$\begin{aligned} \text{CO}_2\text{e, tpy} &= (49,432,569.03 \text{ lb/yr CO}_2)(1 \text{ lb CO}_2\text{e/lb CO}_2) + (931.80 \text{ lb/yr CH}_4) \\ &\quad (25 \text{ lb CO}_2\text{e/lb CH}_4) + (93.18 \text{ lb/yr N}_2\text{O})(298 \text{ lb CO}_2\text{e/lb N}_2\text{O}) \\ &= 49,483,631.67 \text{ lb/yr} = 24,741.82 \text{ tpy} = 2,061.82 \text{ tons/month} \end{aligned}$$

- Circuit Breakers: SF₆

From *Table 5.1A-2—SF₆ Direct Fugitive Emissions* in the Application, SERC will have one SF₆ breaker with a total capacity of 45 pounds.

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Pursuant to the *Regulation for Reducing Sulfur Hexafluoride Emissions from Gas Insulated Switchgear* (17 CCR 95350-95359), §95352 specifies the maximum annual SF₆ emission rate shall not exceed 1.0% in 2020, and each calendar year thereafter. The SERC Project Team estimates the loss rate from circuit breakers is less than 0.5% wt. per year. (The SERC is not subject to GHG PSD BACT, which imposes the same maximum loss rate of 0.5% wt.)

$$\text{Annual leakage} = (45 \text{ lb SF}_6) (0.5/100 \text{ annual leak rate}) = 0.225 \text{ lb/yr SF}_6 = 0.00011 \text{ tpy}$$

Pursuant to Table A–1 to Subpart A of 40 CFR Part 98—Global Warming Potentials, as discussed above, SF₆ is equivalent to 22,800 times the global warming potential of CO₂.

$$(0.225 \text{ lb/yr SF}_6) (22,800 \text{ lb CO}_2\text{e/lb SF}_6) = 5130.0 \text{ lb/yr} = 2.57 \text{ tpy CO}_2\text{e} \\ = 0.21 \text{ tons/month CO}_2\text{e}$$

- New Source Review (NSR) Tracking System

This section develops the internal NSR Data Summary Sheet entries.

$$\text{Operating Schedule: } 52 \text{ wks/yr, } 7 \text{ days/wk, } 24 \text{ hrs/day (annualized schedule)} \\ \rightarrow 8736 \text{ hr/yr}$$

The hourly emissions are back calculated from the annual emissions and used for the purpose of input for the internal NSR Data Summary Sheet only.

$$\text{CO}_2 = (49,483,631.67 \text{ lb/yr}) (\text{yr} / 8736 \text{ hr}) = 5664.34 \text{ lb/hr}$$

$$\text{CH}_4 = (931.57 \text{ lb/yr}) (\text{yr} / 8736 \text{ hr}) = 0.11 \text{ lb/hr}$$

$$\text{N}_2\text{O} = (93.16 \text{ lb/yr}) (\text{yr} / 8736 \text{ hr}) = 0.01 \text{ lb/hr}$$

$$\text{SF}_6 = (0.225 \text{ lb/yr}) (\text{yr} / 8736 \text{ hr}) = 0.000026 \text{ lb/hr}$$

CO₂e = NSR Tracking System automatically calculates from emission rates of CO₂, CH₄, N₂O, and SF₆.

C. Toxic Pollutants

The Application provided hazardous and toxic pollutant emissions calculations in *Table 5.1A-4—Calculation of Hazardous and Toxic Pollutant Emissions from Combustion Turbines* for the Rule 1401 health risk assessment (HRA). The calculations included the use of emission factors and control efficiencies that are not approved by the SCAQMD for a health risk assessment. In a letter dated 12/2/16, the SCAQMD requested that SERC use the provided SCAQMD-approved emission factors and control efficiencies. The SERC Response Letter, 12/29/16,

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included revised *Table 5.1A-4*, which was stated to use SCAQMD-approved emission factors but continued to use control efficiencies that are not approved by the SCAQMD. The letter also included revised *Table 5.9-8—SERC HRA Summary*. In a letter dated 2/2/17, the SCAQMD requested a guarantee from the CO catalyst manufacturer for the unapproved control efficiencies. The SERC Response Letter, 2/15/17, provided revised *Table 5.1A-4*, which removed the use of the unapproved control efficiencies. The letter included revised *Table 5.9-8*.

A final review of the revised *Table 5.1A-4*, submitted 2/15/17, indicated that not all the emission factors in the table reflected the SCAQMD-approved emission factors provided in the SCAQMD Letter, dated 12/2/16. In a letter dated 10/6/17, the SCAQMD requested SERC to use only the SCAQMD-approved emission factors and provide a revised health risk assessment. In an e-mail, dated 10/10/17, SERC provided revised emissions calculations using only SCAQMD-approved emission factors and a revised HRA. SERC Response Letter, 10/31/17, provided a revised *Table 5.9-8-SERC HRA Summary*.

The toxic emissions, based on SCAQMD-approved emission factors and control efficiencies, which were incorporated in the SERC Response Letter, 10/31/17, are shown in the table below.

Table 24--Toxic Air Contaminants/Hazardous Air Pollutants per Turbine

Pollutant	CAS	TAC/HAP	Emission Factor ¹ lb/MMscf	Emissions per Turbine		
				lb/hr	lb/yr	Ton/yr
Ammonia ⁴	766417	TAC	5 ppm	3.30	2977	1.49
Acetaldehyde ²	75070	TAC & HAP	0.179	0.0852	74.36	0.037
Acrolein ²	107028	TAC & HAP	0.00368	0.0018	1.53	0.00077
Benzene ²	71432	TAC & HAP	0.00332	0.0016	1.38	0.00069
1,3-Butadiene	106990	TAC & HAP	0.000437	0.0002	0.182	0.000091
Ethylbenzene	100414	TAC & HAP	0.0325	0.0155	13.52	0.0068
Formaldehyde ²	50000	TAC & HAP	0.366	0.1743	152.1	0.076
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	0
Naphthalene	91203	TAC & HAP	0.00132	0.0006	0.55	0.00027
PAHs (excluding naphthalene) ³ [(2.2E-06 – 1.3E-06) MMBtu/hr] [1017 Btu/scf] = 0.000915 lb/mmscf	1151	TAC & HAP	0.000915	0.0004	0.3801	0.00019
Propylene ⁴	115071	TAC	0	0	0	0

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Pollutant	CAS	TAC/HAP	Emission Factor ¹ lb/MMscf	Emissions per Turbine		
				lb/hr	lb/yr	Ton/yr
Note: EF is 0 because AP-42 does not provide an emission factor and CATEF factors are not SCAQMD-approved.						
Propylene Oxide	75569	TAC & HAP	0.0295	0.014	12.25	0.0061
Toluene	108883	TAC & HAP	0.132	0.0629	54.93	0.027
Xylene	1330207	TAC & HAP	0.0651	0.031	27.04	0.014
Total Annual HAPS Emissions per Turbine, TPY						0.169
Total Annual Toxic Air Contaminants Emissions per Turbine, TPY						1.659

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. The table provides factors in lb/MMBtu. To convert from lb/MMBtu to lb/MMscf, multiply by 1017.2 Btu/scf, as provided by SERC in *Table 5.1A-1 Rev. S3 Design Fuel Gas Analysis* in the Application.

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. These emission factors include control by CO catalyst.

³ Carcinogenic PAHs only. Naphthalene was 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:

For compounds other than ammonia

Hourly emissions, lb/hr = (Emission Factor) [maximum hourly heat input rate of 484.2 MMBtu/hr (HHV) (Case 106)] (scf/1017.2 Btu) = (Emission Factor) (0.476 MMscf/hr)

Annual emissions, lb/yr = (Emission Factor) [average hourly heat input rate of 468.5 MMBtu/hr (HHV) (Case 103)] (902 hr/yr maximum) (scf/1017.2 Btu) = (Emission Factor) (415.44 MMscf/yr)

(Using the same basis as for the determination of the SO_x emission factor for *Table 23 - Turbine Normal Operating Emission Factor for SO_x - Annual Limit*)

Ammonia

Maximum hourly emissions, lb/hr = [484.2 MMBtu/hr (case 106)] (8710 dscf/10⁶ Btu) (5 ppm NH₃ /10⁶) (20.9/(20.9-15.0)) (17 lbs NH₃/379 scf) = 3.3 lb/hr

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2. A/N 589937, 589938—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. 1 and 2
 Operating Schedule: 52 wk/yr, 7 days/wk, 24 hrs/day

A. Criteria Pollutants

$$\text{NO}_x = \text{CO} = \text{VOC} = \text{PM}_{10} = \text{SO}_x = 0 \text{ lb/hr} = 0 \text{ lb/day}$$

B. Toxic Pollutants

From *Table 24--Toxic Air Contaminants/Hazardous Air Pollutants per Turbine*, above:
 $2976.6 \text{ lb/yr} = 1.49 \text{ ton/yr} = 0.124 \text{ ton/month}$.

To calculate hourly emission rate for annualized operating schedule (52 wk/yr, 7 days/wk, 24 hr/day, same as turbines.)

$$\begin{aligned} \text{NH}_3, \text{ lb/day} &= (2976.6 \text{ lb/yr}) (\text{yr}/52 \text{ wk}) (\text{wk}/7 \text{ days}) = 8.18 \text{ lb/day} \\ \text{lb/hr} &= (8.18 \text{ lb/day}) (\text{day}/24 \text{ hr}) = 0.34 \text{ lb/hr} \end{aligned}$$

Note: Ammonia is not a federal HAP.

3. A/N 589941--Ammonia Storage Tank

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

No emissions are expected because the filling losses will be controlled by a vapor return line and the breathing losses by the 2.5 psig pressure relief valve.

$$\text{NH}_3 = 0 \text{ lb/hr} = 0 \text{ lb/day}$$

4. Summary of Facility Maximum Monthly, Daily, and Annual Emissions, Normal Operation

a. Maximum Monthly Emissions, Normal Operations

The facility maximum monthly emissions are calculated for the public notice.

Table 25 - Facility Maximum Monthly Emissions

Equipment	Tons/Month						
	NO _x	CO	VOC	PM ₁₀ /PM _{2.5}	SO _x	NH ₃	CO _{2e}
Simple-Cycle Turbine	1.8	1.85	0.58	1.12	0.38		2061.82
Simple-Cycle Turbine	1.8	1.85	0.58	1.12	0.38		2061.82
SCR/CO Catalyst						0.124	
SCR/CO Catalyst						0.124	
Ammonia Tank						0	
Circuit Breakers							0.21
Facility Total	3.60	3.70	1.16	2.24	0.76	0.25	4123.85

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b. Maximum Daily Emissions, Normal Operations

The facility maximum daily emissions are calculated for the public notice. For this purpose only, the daily emissions are the monthly emissions from the table above, divided by 30 days.

Table 26 - Facility Maximum Daily Emissions

	Tons/Day						
	NOx	CO	VOC	PM ₁₀ /PM _{2.5}	SOx	NH ₃	CO _{2e}
Facility Total	0.12	0.12	0.04	0.07	0.025	0.008	137.46

c. Maximum Annual Emissions, Normal Operations

The facility maximum annual emissions are calculated for the public notice and for the purpose of rule applicability and requirements, as discussed under the rule analysis section below.

Table 27 - Facility Maximum Annual Emissions

Equipment	Tons/Year						
	NOx	CO	VOC	PM ₁₀ /PM _{2.5}	SOx	NH ₃	CO _{2e}
Simple-Cycle Turbine	1.96	2.29	0.86	1.35	0.15		24,741.82
Simple-Cycle Turbine	1.96	2.29	0.86	1.35	0.15		24,741.82
SCR/CO Catalyst						1.49	
SCR/CO Catalyst						1.49	
Ammonia Tank						0	
Circuit Breakers							2.57
Facility Total	3.92	4.58	1.72	2.70	0.30	2.98	49,486.21

RULE EVALUATION

The SERC project is expected to comply with all applicable SCAQMD rules and regulations, and federal and state regulations, as follows:

DISTRICT RULES AND REGULATIONS

Rule 202--Temporary Permit To Operate

- (a) New Equipment - A person shall notify the Executive Officer before operating or using equipment granted a permit to construct. Upon such notification, the permit to construct shall serve as a temporary permit for operation of the equipment until the permit to operate is granted or denied. The equipment shall not be operated contrary to the conditions specified in the permit to construct. (See Rule 205 for analysis for Rules 202 and 205.)

Rule 205—Expiration of Permit to Construct

This rule provides that a permit to construct shall expire one year from the date of issuance unless an extension of time has been approved in writing by the Executive Officer.

Analysis: Rules 202 and 205 requirements are set forth in condition 1.b in *Section E: Administrative Conditions* of the facility permit. Section E is comprised of a standard list of

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operating conditions that apply to all permitted equipment at the facility unless superseded by condition(s) listed elsewhere in the permit. For clarity and completeness, condition E193.2 reiterates condition 1.b in *Section E*.

Rule 212—Standards for Approving Permits

Rule 212 public notice **is** 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. SERC Response Letter, 5/17/17, clarified that the nearest K-12 school is Robert M. Pyles Elementary School, 10411 S. Dale Avenue, Stanton, CA. The distance between the closest project stack location and the school’s southern boundary is approximately 1299 feet. The distance was obtained by projecting the project map to the Universal Transverse Mercator North American Datum 83.

As discussed below under *Rule 1303(b)(1)—Modeling*, SCAQMD Planning, Rule Development & Area Sources (PRDAS) staff reviewed the dispersion modeling analysis and the health risk assessment provided by the applicant for this project. From the modeling files, staff determined the distance is 1280 feet.

- ***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** require public notice because the on-site emission increases from the SERC will exceed the daily maximum thresholds set forth in subdivision (g) for VOC, NO_x, PM₁₀, and CO, as shown in the table below. For the purposes of this rule, the on-site emission increases are interpreted as the maximum monthly emissions for the facility divided by 30 days. The maximum monthly emissions for two turbines is from *Table 16—Maximum Monthly Emissions per Turbine and Total Project (Two Turbines)*.

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Table 28 - Rule 212(c)(2) Applicability

	VOC	NOx	PM ₁₀	SOx	CO	Lead
SERC 30-day averages, lb/day	2311.36 lb/30 day = 77 lb/day	7201.84 lb/30 day = 240 lb/day	4474.40 lb/30 day = 149 lb/day	1515.30 lb/30 day = 51 lb/day	7380.48 lb/30 day = 246 lb/day	0 lb/30 day = 0 lb/day
Rule 212(c)(2) Daily Maximum, lbs/day	30	40	30	60	220	3
Increase Exceed Daily Maximum?	Yes	Yes	Yes	Yes	Yes	No

The public notice requirements for subdivision (c)(2) are found in subdivisions (d) and (g). The District will prepare the public notice which will contain sufficient information to fully describe the project.

Subdivision (d) requires the applicant to distribute the public notice to each address within a ¼-mile radius of the project, including Robert M Pyles Elementary School. The distributed public notice will state that comments must be received within 33 days of the date of distribution of this notice in order to allow a full 30-day comment period required by (g)(4), discussed below. If the comment period end date falls on a Saturday, Sunday, or Monday, the end date is extended so that the deadline falls on an SCAQMD business day to allow commenters access to SCAQMD staff on the end date.

Subdivision (g) requires that the public notification and comment process include all applicable provisions of 40 CFR Part 51, Section 51.161(b) and 40 CFR Part 124, Section 124.10. The minimum requirements specified in the above provisions are included in subparagraphs (g)(1), (g)(2), (g)(3), and (g)(4).

Pursuant to (g)(1), the SCAQMD will make the following information available for public inspection at Stanton Library, 7850 Katella Avenue, Stanton, CA 90680, during the 30-day comment period: (1) public notice, (2) draft permits, and (3) District's permit to construct engineering evaluation (also called Preliminary Determination of Compliance).

Pursuant to (g)(2), the SCAQMD will publish the public notice in a newspaper which serves the area that will be impacted by the project, i.e., The Register.

Pursuant to (g)(3), the SCAQMD will mail the public notice to the following persons: the applicant; EPA administrator for Region IX; California Air Resources Board; affected local air pollution control districts; chief executives of the city and county where the project will be located; regional land use planning agency; State and Federal Land Managers; and Indian Governing Body whose lands may be affected by emissions from the proposed regulated activity.

Pursuant to Rule 212(h), the SCAQMD may combine public notices to avoid duplication provided that all required public notice requirements are satisfied. The Rule 212(c)(2) public notice will be combined with the Rule 3006 Title V public notice for a single public notice.

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(The Title V public notice requirements and completion are discussed below under Regulation XXX – Title V.)

Pursuant to (g)(4), a 30-day period for submittal of public comments is required. Any person wishing to comment on the air quality elements of the permits must submit comments in writing to the SCAQMD within 30 days of the publication of the notice. The deadline for comments is included in the published public notice. If the comment period end date falls on a Saturday, Sunday, or Monday, the end date is extended so that the deadline falls on an SCAQMD business day to allow commenters access to SCAQMD staff on the end date.

Rule 212 Public Notice Requirements Completion

The PDOC (engineering evaluation) and proposed initial Title V permit were issued for review on 2/9/18.

- *Publication of Public Notice*
On 2/14/18, the Notice of Intent to Issue Permits Pursuant to SCAQMD Rules 212 and 3006 was published in The Orange County Register. The public comment period ended on 3/15/18. Also see Regulation XXX – Title V, below.
- *EPA Initial Permit Issuance Review for Title V*
On 2/9/18, SCAQMD electronically submitted the public notice, PDOC analysis, and proposed initial Title V facility permit to the EPA for the 45-day review. Also see Regulation XXX – Title V, below.
- *SCAQMD Distribution of Public Notice*
On 2/9/18, SCAQMD mailed (or e-mailed, if requested) the public notice (also PDOC analysis and proposed Title V facility permit, as appropriate) to SERC and other persons required by Rule 212(g)(3), environmental groups, and interested parties.
- *SCAQMD Submittal to CEC*
On 2/9/18, SCAQMD electronically submitted the public notice, PDOC analysis, and proposed Title V facility permit to the CEC.
- *SCAQMD Website Availability of Public Notice*
On 2/9/18, the public notice, PDOC analysis and proposed Title V facility permit were available for review on the SCAQMD website.
- *Library Availability of Public Notice*
The public notice, PDOC analysis and proposed Title V facility permit were available for public review at the SCAQMD’s headquarters in Diamond Bar, and at the Stanton Library, 7850 Katella Avenue, Stanton, CA 90680.

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- *AES Distribution of Public Notice to Each Address Within ¼ mile Radius of the Project*
In a letter dated 3/12/18, Douglas Davy, CH2M, provided the following verification that the public notice was distributed to all addresses within one-quarter mile of the facility: (1) copy of the public notice with a distribution date of 3/6/18; (2) map showing the ¼-mile public notice radius; (3) list of addresses to which the public notice was mailed; and (4) USPS receipt, dated 3/1/18, for stamps. In addition, SERC provided a Declaration of Service, signed by Mr. Davy on 3/15/18, stating that the public notice letters were mailed at the USPS on 3/1/18 or 3/2/18. The distribution date provided on the notice was 3/6/18. The public notice stated that public comments must be received within 33 days of the date of distribution on the notice. The reason for allowing 33 days is to ensure the recipient has a full 30 days to review the notice, after receiving the notice in the mail. The public comment period ended on 4/10/18, which is the first SCAQMD business day after the end of the 33-day period.

- *Comment Letter(s)*
The only comments received were from SERC in a letter, dated 2/20/18. The SCAQMD provided responses in a letter, dated 4/19/18, which agreed to administrative type changes to permit conditions.

- *FDOC Appendix for Comments and SCAQMD Responses*
Appendix B has been added to this FDOC to include the comments received during the comment period, and the SCAQMD's responses to the comments.

- ***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 increases in toxic emissions from each turbine will not expose a person to a maximum individual cancer risk that is greater than or equal to one in a million. See the Rule 1401 rule analysis below.

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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 will be equipped with an SCR to control NOx emissions. A NOx CEMS is required to be installed on each turbine to demonstrate compliance with the NOx limits of 2.5 ppmvd at 15% O₂ per Rule 1303(a)(1)--BACT, and 25 ppmv at 15% O₂ per 40 CFR 60 Subpart KKKK, as well as to monitor NOx emissions per 40 CFR Part 75. Subparagraph (b)(1)(A) specifies that this rule shall not apply to CEMS subject to RECLAIM, Regulation IX – New Source Performance Standards (NSPS), or Regulation XXXI—Acid Rain Program. The NOx CEMS will not be subject to RECLAIM, but will be subject to 40 CFR 60 Subpart KKKK--NSPS for Stationary Gas Turbines and 40 CFR Part 75--Continuous Emission Monitoring for the Acid Rain Program. Therefore the NOx CEMS will not be subject to Rules 218 and 218.1, but will be subject to Subpart KKKK and Part 75, as discussed in the regulatory analysis below.

Each turbine will be 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 4.0 ppmvd at 15% O₂ per Rule 1303(a)(1), required by condition A195.2. In addition, the CO CEMS will demonstrate compliance with the monthly and annual emissions limits in conditions A63.1 and A63.2, respectively. Further, the CO CEMS will demonstrate compliance with the start-up and shut-down durations and emission limits set forth in conditions C1.1 and C1.2, respectively, to

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minimize CO emissions for startups and shutdowns during which steady state BACT is not achievable. The CO CEMS will be subject to Rules 218 and 218.1. The CO CEMS requirements will be set forth in condition D82.1.

- (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

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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: Condition D82.1 will require the CO CEMS to be reviewed and certified according to the requirements of Rules 218 and 218.1 per subparagraph (c)(1)(B)(i). The CEMS will be required to be installed and operating no later than 90 days after initial start-up of the turbine, and in accordance with an approved SCAQMD Rule 218 CEMS plan application (standard power plant condition).

- (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: The CO CEMS is expected to be in compliance.

- (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.

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Analysis: A CO CEMS is required on each turbine to ensure compliance with BACT requirements, pursuant to Rule 1303(a)(1). The CO CEMS will demonstrate compliance with the CO BACT limit of 4.0 ppmvd at 15% O₂, required by condition A195.2. In addition, the CO CEMS will demonstrate compliance with the monthly and annual emissions limits in conditions A63.1 and A63.2, respectively, to ensure compliance with BACT requirements. Further, the CO CEMS will demonstrate compliance with the start-up and shut-down durations and emission limits set forth in conditions C1.1 and C1.2, respectively, to minimize CO emissions for startups and shutdowns during which steady state BACT is not achievable.

Accordingly, condition D82.1 will require the CO CEMS to measure the concentration in ppmv, correct the concentration to 15 percent oxygen on a dry basis, and measure concentrations over a 15 minute averaging time period. The CEMS will be required to convert the actual concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.

- (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: For the interim period after commissioning but prior to CEMS certification, and in the event of CEMS failure subsequent to CEMS certification, the operator shall use the CO emission factor provided in condition A63.1 for this purpose.

Rule 218.1--Continuous Emission Monitoring Performance Specifications

- (b) Standards for New or Modified CEMS
- In order to be a Certified CEMS, a CEMS subject to the provisions of Rule 218 Sections (c)(1), (d)(1)(C), (d)(1)(D)(i), (d)(2)(C) and (d)(2)(D), as applicable, shall meet the operational requirements, performance specifications, and standards as follows:

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- (1) Pre-Certification Testing Requirements for New or Modified CEMS Before any certification or relative accuracy test is performed, the CEMS shall meet the following standards:
 - (A) CEMS Location
 - (B) Sampling Location
 - (C) Full Span Range (FSR)
 - (D) Strip Chart Recorder
 - (E) Data Acquisition System (DAS)
 - (F) Operational Period

- (2) Certification Requirements and Performance Specifications for New or Modified CEMS Rule 218(c)(1) provides that a series of certification tests shall be performed to demonstrate the acceptability of CEMS performance. The requirements and specifications in conducting initial certification tests follow:
 - (A) Calibration Error (CE) Testing
 - (B) Analyzer Enclosure
 - (C) Relative Accuracy

- (3) Relative Accuracy Test Requirements for New or Modified CEMS Within fourteen days of, or during all relative accuracy tests, the CEMS shall meet the following requirements, except those that may be waived as allowed in Rule 218.1, Section (b)(4)(C):
 - (A) Response Time
 - (B) Calibration Error
 - (C) Concentration Stratification
 - (D) Cyclonic Flow
 - (E) Interference
 - (F) Linearity Error
 - (G) Multiple -Span-Range

- (4) Operational Requirements and Performance Specifications for New or Modified CEMS After final approval, the CEMS shall be subsequently operated and maintained according to the following requirements and specifications:
 - (A) 24-Hour CE
 - (B) System Bias Test
 - (C) Relative Accuracy Testing
 - (D) Cylinder Gas Audit (CGA)

- (d) Standards, Specifications and Requirements for New, Modified and Existing CEMS:
 - (1) Calibration Gas
 - (2) Zero Gas
 - (3) Automatic Calibration Data
 - (4) F-Factors

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(5) NO₂ to NO Conversion Efficiency

Analysis: Condition D82.1 will require the CO CEMS to be reviewed and certified according to the requirements of Rules 218 and 218.1 per Rule 218(c)(1)(B)(i).

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

Process 3: Rule 219 Exempt Equipment Subject To Source-Specific Rules of the facility permit will include the following equipment. Source-specific rules are found in Regulation XI.

1. Coating Equipment, Portable, Architectural Coating

Rule 219(1)(9) exempts portable coating equipment used exclusively for the application of architectural coatings and associated internal combustion engines provided such equipment is exempt pursuant to paragraph (b)(1), which exempts internal combustion engine with a rating of 50 bhp or less.

This coating equipment is standard Rule 219 equipment included on facility permits, and is subject to the associated standard periodic monitoring condition K67.1 for recordkeeping, as well as to Rules 1113 and 1171.

- Rule 1113—Architectural Coatings

Subdivision (a) provides that this rule is applicable to any person who supplies, sells, markets, offers for sale, or manufactures any architectural coating that is intended to be field applied within the District to stationary structures or their appurtenances, and to fields and lawns; as well as any person who applies, stores at a worksite, or solicits the application of any architectural coating within the District. The purpose of this rule is to limit the VOC content of architectural coatings used in the District.

Subdivision (c) provides VOC limits for various coating categories, which will be reproduced in *Appendix B: Rule Emission Limits* of the facility permit. Appendix B will include the emission limits for both the SIP-approved version and the most recent version (if different from SIP-approved version) of the rule.

Paragraph (g)(1) provides that solvent cleaning that is conducted as part of a business including solvent cleaning of architectural coating application equipment and the storage and disposal of VOC-containing materials used in cleaning operations are subject to the provisions of Rule 1171 - Solvent Cleaning Operations.

- Rule 1171—Solvent Cleaning Operating

Subdivision (a) provides that the purpose of this rule is to reduce emissions of volatile organic compounds (VOCs), toxic air contaminants, and stratospheric ozone-depleting or global warming compounds from the use, storage and disposal of solvent cleaning materials in solvent cleaning operations and activities. A solvent cleaning operation is solvent cleaning conducted as part of a business. This rule applies to: all persons who use

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these solvent materials in solvent cleaning operations during the production, repair, maintenance, or servicing of parts, products, tools, machinery, equipment, or general work areas; all persons who store and dispose of these materials used in solvent cleaning operations; and all solvent suppliers who supply, sell, or offer for sale solvent cleaning materials for use in solvent cleaning operations.

Paragraph (c)(1) provides VOC limits for various solvent cleaning categories, which will be reproduced in *Appendix B: Rule Emission Limits* of the facility permit. Appendix B will include the emission limits for both the SIP-approved version and the most recent version (if different from SIP-approved version) of the rule. Paragraph (c)(2) provides requirements for cleaning devices and methods, (c)(4) for storage and disposal, and (c)(6) for recordkeeping.

2. Air Conditioning Units

Rule 219(d)(1) exempts comfort air conditioning or ventilation systems which are not designed or used to remove air contaminants generated by, or released from, specific equipment units, provided such systems are exempt pursuant to paragraph (b)(2). Paragraph (b)(2) exempts boilers with rated maximum heat input capacity of 2,000,000 Btu/hr (gross) or less and are equipped to be heated exclusively with natural gas, methanol, liquefied petroleum gas, or any combination thereof.

This equipment was listed by the applicant in Form 500-B—Title V List of Exempt Equipment, and is subject to Rule 1415 and 40 CFR 82, Subpart F.

- Rule 1415—Reduction of Refrigerant Emissions from Stationary Air Conditioning Systems
Subdivision (a) provides the purpose of this rule is to reduce emissions of high-global warming potential refrigerants from stationary air conditioning systems by requiring persons subject to this rule to reclaim, recover, or recycle refrigerant and to minimize refrigerant leakage. Subdivision (b) indicates this rule is applicable to any person who owns or operates an air conditioning system, installs, repairs, maintains, services, relocates, or disposes of an air conditioning system; to any person who services or maintains recycling and recovery equipment; and to any person who recycles, recovers, reclaims, or sells high global warming potential refrigerant.

Paragraph (c)(2) defines “air conditioning system” to mean “any stationary, non-residential appliance, which holds more than 50 pounds of high global warming potential refrigerant, and provides cooling to a space to an intended temperature of not less than 68 °F for the purpose of cooling objects or occupants. Computer-room air conditioner is included in this definition.”

Subdivision (d) provides requirements for filing a Registration Plan, annual audits for refrigerant leaks, and leaks repair. Subdivision (e) provides requirements for recordkeeping.

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- 40 CFR 82—Protection of Stratospheric Ozone, Subpart F Recycling and Emissions Reduction
§82.150 Purpose and Scope

(a) The purpose of this subpart is to reduce emissions of class I and class II refrigerants and their non-exempt substitutes to the lowest achievable level by maximizing the recapture and recycling of such refrigerants during the maintenance, service, repair, and disposal of appliances and restricting the sale of refrigerants consisting in whole or in part of a class I or class II ozone-depleting substance or their non-exempt substitutes in accordance with Title VI of the Clean Air Act.

(b) This subpart also applies to appliance owners and operators.

§82.156 Proper evacuation of refrigerant from appliances.

(i) The provisions in this paragraph (i) apply to owners and operators of appliances containing 50 or more pounds of class I and class II refrigerants only until January 1, 2019. This section provides leak repair requirements.

§82.157 Appliance Maintenance And Leak Repair.

(a) *Applicability.* This section applies as of January 1, 2019. This section applies only to appliances with a full charge of 50 or more pounds of any class I or class II refrigerant or any non-exempt substitute refrigerant. Unless otherwise specified, the requirements of this section apply to the owner or operator of the appliance.

(b) *Leak Rate Calculation*

(c) *Requirement to Address Leaks through Appliance Repair, or Retrofitting or Retiring an Appliance*

(d) *Appliance Repair*

(e) *Verification tests.*

(f) *Extensions to the appliance repair deadlines*

(g) *Leak Inspections*

(h) *Retrofit or retirement plans*

(i) *Extensions to the one-year retrofit or retirement schedule.*

(j) *Chronically leaking appliances*

(k) *Purged refrigerant*

(l) *Recordkeeping*

(m) *Reporting*

§82.166 Reporting And Recordkeeping Requirements For Leak Repair

This section contains leak repair reporting and recordkeeping requirements that apply to owners and operators of appliances containing 50 or more pounds of class I or class II refrigerants until January 1, 2019. Starting January 1, 2019, the recordkeeping and reporting requirements in the leak repair provisions in §82.157(l) and (m) apply to owners and operators of appliances containing 50 or more pounds of class I or class II refrigerants or non-exempt substitutes.

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Process 3 will not include the following Rule 212 equipment because it is not subject to source-specific rules.

3. Building Heating Systems

Rule 219(d)(6) exempts equipment used exclusively for space heating provided such equipment is exempt pursuant to paragraph (b)(2).

This equipment was listed by the applicant in Form 500-B—Title V List of Exempt Equipment, but will not be added to Process 3 because it is not subject to a source-specific rule.

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 be firing 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.

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.

Subdivision (d) sets forth the requirements applicable to all persons. Paragraph (d)(2) specifies no person shall conduct active operations without utilizing the applicable best available control measures included in Table 1 to minimize fugitive dust emissions from each fugitive dust source type within the active operation.

During the construction period, the project may also be subject to subdivision (e)—Additional Requirements for Large Operations, which requires the implementation of applicable actions specified in Table 2 of the rule at all times and the implementation of applicable actions specified in Table 3 of the rule when the applicable performance standards cannot be met through use of Table 2 actions. The requirements include the submittal of: (1) a fully executed Large Operation Notification (Form 403N) to the SCAQMD Compliance Department by a representative that has completed the SCAQMD Fugitive Dust Control Class and has been issued a valid Certificate of Completion for the class; and (2) daily records to document the specific dust control actions taken. This rule does not require the submittal of a fugitive dust control plan.

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The PDOC/FDOC is intended to provide an evaluation of operating emissions, including fugitive emissions emitted during the operation of a facility, and the control of these emissions to meet regulatory requirements. The PDOC/FDOC is not intended to evaluate fugitive emissions emitted during the construction phase or construction mitigation requirements to ensure compliance with Rule 403.

During normal operations, fugitive emissions are not expected from the operation of the turbines, SCR/oxidation catalysts, and ammonia tank. 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 be controlled by an oxidation catalyst to the BACT limit of 4 ppmvd at 15% O₂. 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% CO₂, averaged over a minimum of 15 consecutive minutes.

Each gas turbine is expected to meet this limit at the maximum firing load based on the calculations shown below, which shows the grain loading is expected to be **0.012 gr/scf**.

$$\text{Grain Loading} = [(A * B)/(C * D)] * 7000 \text{ gr/lb}$$

where:

- A = Maximum PM₁₀ emission rate during normal operation, 3.0 lb/hr (Cases 100 – 108)
- B = Rule specified percent of CO₂ in the exhaust (12%)
- C = Percent of CO₂ in the exhaust (approx. 4.29% for natural gas)
- D = Stack exhaust flow rate, scf/hr

$$D = F_d * \frac{20.9}{(20.9 - \% O_2)} * TFD = 8710 * \frac{20.9}{17.9} * 484.2 = 4.92 \text{ E}+06 \text{ scf/hr}$$

where:

- F_d = Dry F factor for fuel type = 8710 dscf/MMBtu
- O₂ = Dry oxygen content in the effluent stream = 3%

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TFD = Total fired duty measured at HHV, 484.2 MMBTU/hr

Grain Loading = $[(3.0 * 12) / (4.29) (4.92 \text{ E}+06)] * 7000 = 0.012 \text{ gr/scf} < 0.1 \text{ gr/scf limit}$

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

Subdivision (a) limits NO_x, expressed as NO₂, calculated at 3% O₂ on a dry basis, from any non-mobile fuel burning equipment to the concentration shown in the table in the rule. The maximum gross heat input rate for each turbine is 484.2 MMBtu/hr. As the lowest gross heat input rate for which the table provides a NO_x limit is 555 MMBtu/hr, the table does not provide a limit for the turbines.

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.

Each turbine is expected to meet the 11 lb/hr limit. For the purpose of determining offsets, the turbines will be limited to 3.0 lb/hr PM₁₀.

Each turbine is expected to meet the 0.01 grain/scf limit at the maximum firing rate. Based on the calculations shown below, the concentration is expected to be **0.004 gr/scf**.

Combustion Particulate (gr/scf) = $(\text{PM}_{10}, \text{ lb/hr} / \text{Stack Exhaust Flow, scf}) * 7000 \text{ gr/lb}$

PM₁₀ = 3.0 lb/hr (Cases 100 – 108)

Stack exhaust flow = 4.92 E+06 scf/hr (from Rule 409 analysis above)

Combustion Particulate = $(3.0 / 4.92 \text{ E}+06) * 7000 = 0.004 \text{ gr/scf} < 0.01 \text{ gr/scf limit}$

Rule 1134 – Emissions of NO_x from Stationary Gas Turbines

The provisions of this rule shall apply to all existing stationary gas turbines, 0.3 megawatt (MW) and larger, as of August 4, 1989. Therefore, as new installations, the proposed turbines are not subject to this rule.

Rule 1135 – Emissions of NO_x from Electric Power Generating Systems

This rule applies to electric power generating systems. Paragraph (b)(10) defines “*electric power generating system*” to mean “all boilers, replacement units and approved alternative or advanced combustion resources owned or operated by, and approved alternative or advanced combustion

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resources and replacement units under contract to sell power to, any one of the following: Southern California Edison, Los Angeles Department of Water and Power, City of Burbank, City of Glendale, City of Pasadena, or any of their successors.”

Paragraph (b)(2) defines “*alternative resource*” to mean “a resource, within or outside the District, irrespective of ownership, capable of generating electricity in a non-conventional manner, including, but not limited to: solar; geothermal; wind; fuel cells; electricity conservation; and electricity demand-side management measures.” Paragraph (b)(1) defines “*advanced combustion resource*” to mean “a combustion resource, within or outside the District, irrespective of ownership, capable of generating electricity using cogeneration; combined cycle gas turbines; intercooled, chemically recuperated, or other advanced gas turbines; and other advanced combustion processes.”

Although SERC will be supplying power to Southern California Edison’s Barre Substation, the proposed simple-cycle turbines do not fall within the meaning of “*alternative source*” or “*advanced combustion resource*”. Therefore, this rule is not applicable to the SERC.

REGULATION XIII—NEW SOURCE REVIEW (NSR)

Regulation XIII—New Source Review sets forth BACT, modeling, offset, and other requirements for non-attainment pollutants. The SCAQMD is not in attainment for PM₁₀ (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 PM₁₀ (federal 24-hr standard), CO, NO_x, and SO_x. Since NO_x, SO_x, and VOC (no attainment standards for VOC) are precursors to non-attainment pollutants, they are treated as non-attainment pollutants as well. Specifically, NO_x and VOC are precursors to ozone. NO_x and SO_x are precursors to PM₁₀ and PM_{2.5}. Thus, the non-attainment pollutants are NO_x, PM₁₀, PM_{2.5}, SO_x, 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)—BACT**

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

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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.”

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 NO_x, SO_x, ROG, and fine respirable particulate matter (PM₁₀).

Rule 1303(a) sets forth different requirements for major polluting facilities and non-major polluting (minor) facilities.

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- 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 (NO_x) (10) tons per year
 Sulfur Oxides (SO_x) (70) tons per year
 Particulate Matter (PM₁₀) (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 to determine whether SERC is a “major polluting facility” or “minor facility” for the purposes of NSR.

Table 29—New Source Review Major Polluting Facility Applicability

	NO _x	PM ₁₀	SO _x	VOC	CO
Stanton Electric Reliability Center (SERC) Potential to Emit, TPY (<i>Table 27—Facility Maximum Annual Emissions</i>)	3.92	2.70	0.3	1.72	4.58
Potential to Emit Exceeds Threshold?	No, potential to emit is less than 10 tpy.	No, potential to emit is less than 70 tpy.	No, potential to emit is less than 70 tpy.	No, potential to emit is less than 10 tpy.	No, potential to emit is less than 50 tpy.
Major Polluting Facility?	No, the PTEs for NO _x , PM ₁₀ , SO _x , VOC, and CO are less than the respective applicability 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 SERC is not a major polluting facility for any criteria pollutant. Thus, Rule 1303(a)(1) requires BACT for a minor (non-major polluting) facility for NO_x, PM₁₀/PM_{2.5}, SO_x, VOC, and ammonia. As discussed below, Rule 1701(b) requires BACT for a minor facility for CO.

Rule 1303(a)(2) provides that minor sources are not subject to Lowest Achievable Emissions Rate requirements. Further, when the SCAQMD is updating the BACT guidelines to become more stringent, economic and technical feasibility shall be considered in establishing the class or category of sources and the applicable requirements. Rule 1303(a)(3) requires minor source BACT for sources to be 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.

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Part C: Policy and Procedures for Non-Major Polluting Facilities of the SCAQMD Best Available Control Technology Guidelines, amended December 2016, indicates the Guidelines in Part D: BACT Guidelines for Non-Major Polluting Facilities should be used to determine minor source BACT (MSBACT) for non-major polluting facilities.

On p. 33 of the BACT Guidelines, Part C discusses the criteria and process that must be followed to establish new MSBACT, as reproduced below:

Senate Bill 456 (Kelley) was chartered into state law in 1995 and became effective in 1996. H&SC Section 40440.11 specifies the criteria and process that must be followed by the SCAQMD to establish new MSBACT limits for source categories listed in the MSBACT Guidelines. In general, the provisions require:

- Considering only control options or emission limits to be applied to the basic production or process equipment;
- Evaluating cost to control secondary pollutants;
- Determining the control technology is commercially available;
- Determining the control technology has been demonstrated for at least one year on a comparable commercial operation;
- Calculating total and incremental cost-effectiveness;
- Determining that the incremental cost-effectiveness is less than SCAQMD's established cost-effectiveness criteria;
- Putting BACT Guideline revisions on a regular meeting agenda of the SCAQMD Governing Board;
- Holding a Board public hearing prior to revising maximum incremental cost-effectiveness values;
- Keeping a BACT determination made for a particular application unchanged for at least one year from the application deemed complete date; and
- Considering a longer period for a major capital project (> \$10,000,000)

After consultation with the affected industry, the CARB, and the U.S. EPA, and considerable legal review and analysis, staff concluded that the process specified in SB 456 to update the BACT Guidelines should be interpreted to apply only if the SCAQMD proposes to make BACT more stringent than LAER or where LAER is inapplicable (e.g. in establishing minor source BACT). Staff intends to incorporate the spirit and intent of the SB 456 provisions into the MSBACT update process, as explained below, because **non-major polluting facilities are no longer subject to federal**

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LAER, according to Regulation XIII (emphasis added). Therefore, MSBACT may consider cost as specified herein.

On pp. 34-39, Part C explains the cost effectiveness methodology, top-down cost methodology, costs to include in a cost effectiveness analysis, cost factors, and BACT update process.

On pg. 38, Part C further explains that, once a more stringent emission limit or control technology has been reviewed by staff and is determined to meet the criteria for MSBACT, the public will be notified and the BACT Scientific Review Committee will have an opportunity to comment. Following the public process and comment period, the guidelines will be presented to the Governing Board for approval at a public hearing, prior to updates of the MSBACT Guidelines, Part D.

In contrast, on p. 18, *Part A – Policy and Procedures for Major Polluting Facilities* explains LAER requirements are determined on a permit-by-permit basis based on the definition of LAER, and on p. 21, USEPA guidelines do not allow for routine consideration of the cost of control in LAER determinations.

1. A/N 589935, 589936—Simple-Cycle Combustion Turbine Generators Nos. 1 and 2
2. A/N 589937, 589938—Selective Catalytic Reduction/CO Oxidation Catalyst Systems Nos. 1 and 2

- Minor Source BACT for Gas Turbines

The table below shows: (1) the applicable BACT levels for the Gas Turbines from *Part D: BACT Guidelines for Non-Major Polluting Facilities*, p. 62, (2) the limits proposed by SERC, (3) the guaranteed emissions levels from Mitsubishi Hitachi Power Systems Americas, Inc., dated 11/7/17, and (4) whether the proposed and guaranteed emissions levels are in compliance with the SCAQMD BACT levels.

Table 30 – SCAQMD Simple-Cycle Gas Turbine BACT Requirements, Proposed and Guaranteed Emissions Levels

Subcategory/ Ratings/Size	VOC	NOx	SOx	CO	PM ₁₀	Inorganic
Natural Gas Fired ≥ 50 MWe <i>(Part D: BACT Guidelines for Non-Major Polluting Facilities)</i>	2.0 ppmvd (as methane) @ 15% O ₂ , 1-hour avg. OR 0.0027 lbs/MMBtu (higher heating value) (10-20-2000)	2.5 ppmvd @ 15% O ₂ , 1-hour rolling avg. OR 2.0 ppmvd @ 15% O ₂ , 3-hour rolling avg. x efficiency (%) ¹ 34% (10-20-2000)		6.0 ppmvd @ 15% O ₂ , 3-hour rolling avg. (10-20-2000)		5.0 ppmvd ammonia @ 15% O ₂ (10-20-2000)
SERC Proposed Limits	2.0 ppmvd (as methane) @ 15% O ₂ , 1-hour avg.	2.5 ppmvd @ 15% O ₂ , 1-hour avg.	Natural Gas	4.0 ppmvd @ 15% O ₂ , 1-hour rolling avg.	Natural Gas	5.0 ppmvd ammonia @ 15% O ₂

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Subcategory/ Ratings/Size	VOC	NOx	SOx	CO	PM ₁₀	Inorganic
Mitsubishi Hitachi Power Systems Americas Guaranteed Limits, 11/7/17	2.0 ppmvd @ 15% O ₂	2.5 ppmvd @ 15% O ₂		4.0 ppmvd @ 15% O ₂		5.0 ppmvd ammonia @ 15% O ₂
Compliance?	Yes	Yes	Yes	Yes	Yes	Yes

The *Part D BACT Guidelines* provide BACT requirements for VOC, NO_x, CO, and ammonia, but not SO_x and PM₁₀. SERC proposed BACT levels for VOC, NO_x, CO, and ammonia, that are the same or lower than the SCAQMD BACT requirements. For VOC, NO_x, and ammonia, SERC proposed BACT levels that are the same as the SCAQMD BACT levels of 2.0 ppmvd VOC, 2.5 ppmvd NO_x, and 5.0 ppmvd ammonia. Although the net MW for the SERC turbines is < 50 MWe, LM6000 turbines have routinely been subject to more stringent limits and SCAQMD has permitted many LM6000 turbines in the past 10-years with the above limits.

For CO, SERC proposed a BACT level of 4 ppmvd at 15% O₂, 1-hr rolling average, that is more stringent than the SCAQMD BACT level of 6.0 ppmvd at 15% O₂, 3-hour rolling average. As the SERC proposed level is more stringent than the SCAQMD BACT level, the proposed level will be accepted as CO BACT for the turbines for this project only. The acceptance of this limit for this project does not revise minor source BACT, which remains 6.0 ppmvd at 15% O₂, 3-hour rolling average (note that LAER for simple cycle gas turbines is 2 ppm @ 15% O₂, 1-hr rolling average).

For SO_x and PM₁₀, SCAQMD Part D BACT Guidelines do not provide BACT requirements. SERC proposed the exclusive use of pipeline quality natural gas. As the SERC proposed use of pipeline quality natural gas is more stringent than the SCAQMD BACT requirements, the proposed use of natural gas will be accepted as SO_x and PM₁₀ BACT for the turbines for this project only. The acceptance of natural gas for this project does not minor source BACT, which does not provide BACT requirements for SO_x and PM₁₀.

Commissioning, Startups and Shutdowns

Conditions A195.1, A195.2 and A195.3 provide that the BACT limits of 2.5 ppmvd NO_x, 4.0 ppmvd CO, and 2.0 ppmvd ROG, respectively, shall not apply during commissioning, startup, and shutdown periods. In lieu of requiring steady state BACT at all times, an alternative BACT which limits and minimizes emissions during periods when steady state BACT is not achievable, such as during commissioning, startups and shutdowns, has been accepted by EPA.

During commissioning, it is not technically feasible for the turbines to meet steady state BACT limits during the entire period because the combustor may not be optimally tuned

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and the emissions are only partially abated as the CO and SCR catalysts are installed and tested in stages. The turbines, however, are typically operated at less than 100% load during commissioning. To limit the duration of the commissioning period during which BACT is not achievable, condition E193.3 limits the commissioning period to 100 hours of fired operation per turbine, including a maximum of ~~38~~ 20 hours without control (pre-catalyst phase).

During startups, it is not technically feasible for the CTGs to meet steady state BACT limits during the entire startup because the SCR and CO catalysts that are used to achieve the required emissions reductions are not fully effective when the surface of the catalysts are below the manufacturers' recommended operating range. Condition C1.1 specifies limits for startups to minimize startup emissions. The startup limits include: (1) number of starts per calendar month and year; (2) number of starts per day; (3) duration of starts; and (4) NOx and CO emissions per start.

During shutdowns, it is not technically feasible for the turbines to meet steady state BACT limits during the entire shutdown because ammonia injection into the SCR reactor will have ceased operation. The SCR and CO catalysts, however, are still above ambient temperatures and continue to operate for a portion of the shutdown. Condition C1.2 specifies limits for shutdowns to minimize shutdown emissions. The shutdown limits include: (1) number of shutdowns per calendar month and year; (3) number of shutdowns per day; and (4) duration of shutdowns; and (4) NOx and CO emissions per shutdown.

For the purposes of conditions C1.1 and C1.2, the limits are for one turbine, except the annual limits are the combined total for two turbines (D1 and D7). As discussed under Rule 1303(b)(2)—Offsets, below, annual limits to stay under the Rule 1304(d)(1)(A) offset exemption thresholds are to be bubbled over all equipment that emit the specific air pollutants.

3. A/N 589941—Aqueous Ammonia Storage Tank

Part D: BACT Guidelines for Non-Major Polluting Facilities sets forth BACT requirements for Storage Tanks – Liquid on p. 116. Part D does not provide any BACT requirements for inorganic pollutants, however. SERC proposes a pressure relief valve set at 2.5 psig and a vapor return line to the delivery vehicle, which will be required by conditions C157.1 and E144.1, respectively.

The pressure relief valve set at 2.5 psig will control breathing losses. Breathing losses are not expected under normal operating conditions, because the total vapor pressure of 19% aqueous ammonia at 120 °F is 14.4 psia. The vapor return line will control the filling losses.

- Rule 1303(b)(1)—Modeling

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

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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.

Air dispersion modeling is required for NO₂, CO, PM₁₀, PM_{2.5}, and SO₂. (As the standards in Appendix A are outdated, the modeling analyses below are based on current ambient air quality standards.)

Compliance determination is different for attainment and nonattainment pollutants. For attainment pollutants, NO₂, CO, SO₂, PM₁₀ (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, PM₁₀ 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 PM₁₀ (California 24-hr and California annual standards), and PM_{2.5} (federal 24-hr, and California and federal annual standards).

Pursuant to SCAQMD procedure, Planning, Rule Development & Area Sources (PRDAS) staff was requested to review the dispersion modeling analysis and the health risk assessment provided by the applicant for this project. The PRDAS staff reviewed the applicant’s submittal by independently reproducing the dispersion modeling analysis for Rule 1303 and health risk assessment for Rule 1401. The purposes are to verify compliance with SCAQMD rule requirements and support CEC’s CEQA analysis. The modeling review memo, dated 11/29/17, from Health Effects Officer Jo Kay Ghosh, to Sr. Engineering Manager Andrew Lee provided comments on the applicant’s modeling analyses, as well as provided PRDAS’s modeled results, both of which are incorporated below. **(See the Appendix A of this document for a copy of the modeling review memo.)**

AERMOD, METEOROLOGICAL DATA, BACKGROUND DATA

The applicant used AERMOD (version 15181) for the air dispersion modeling which was the current EPA approved model at the time of analysis. As AERMOD requires hourly meteorological data, the meteorological data from the SCAQMD’s Anaheim meteorological station was used, which is appropriate for this project according to PRDAS staff. Five years of MET data (2006-2009 and 2012) were used, which was the appropriate meteorological data set at the time of the analysis. The years 2010 and 2011 were not provided by the SCAQMD as the data recovery rates for those years did not meet the 90 percent completeness requirements. The applicant used the URBAN dispersion option in AERMOD, with a population of 3,010,759 for Orange County, which is appropriate for this project.

The applicant used U.S. Geological Survey (USGS) National Elevation Dataset (NED) 1 arc-second terrain data as input into AERMAP (version 11103) to determine receptor, source, and building elevations, which is appropriate for this project. The modeling domain used was 10 kilometers by 10 kilometers, with fence line spacing of 10 meters. A nested Cartesian receptor grid was used as follows:

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20 meter spacing from the fenceline to approximately 500 meters from the fenceline; 100 meter spacing from 500 meters from the fenceline out to 1 kilometers; 200 meter spacing from 1 kilometer to 5 kilometers; and 500 meter spacing from 5 kilometers to 10 kilometers. Discrete Cartesian receptors were placed at residential and off-site worker locations. The receptor grid selection is appropriate to capture the maximum impacts.

The applicant used monitoring data from SRA 17, Central Orange County monitoring stations for the pollutants CO, NO₂, PM₁₀, and PM_{2.5} and monitoring data from SRA 18, North Coastal Orange County for the pollutant SO₂ for the last three years (2013 – 2015) to determine the background concentrations, which is appropriate for this project at the time of analysis. The predicted modeled impacts were added to the highest background concentrations for comparison to the state and federal ambient air quality standards (AAQS), which is appropriate.

FUMIGATION IMPACTS

Fumigation (both inversion break-up and shoreline fumigation) is a meteorological condition that can produce high concentrations of ground-level pollutants. Fumigation impacts can be greater than impacts predicted with the AERMOD model. To verify that fumigation impacts do not result in higher ambient air quality impacts, the Application provided a screening fumigation modeling analysis.

From p. 5.1-29 of the Application, SERC conducted fumigation analyses with the AERSCREEN (version 15181) for inversion breakup conditions. The annual average stack parameters (Case 103 for 100 percent load at 65 °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.

The remainder of the discussion in the Application, including *Table 5.1-24 Fumigation Impact Summary*, was revised for SERC Response Letter, 5/17/17, in response to a data request from California Energy Commission Staff regarding the fumigation analysis presented in the Application. The data request from Staff’s Data Requests Set 1, A1-A63, posted on April 5, 2017 (TN #216815), is reproduced below:

**FUMIGATION ANALYSIS
BACKGROUND**

The facility owner used the AERSCREEN model to evaluate combustion turbine impacts under inversion breakup conditions because these are special cases of meteorological conditions. Section 5.1.7.3.1 of the AFC show that only the annual average case (Case 103 – 100 percent load at 65 °F) was modeled.

DATA REQUEST

- A6. Please evaluate whether the annual average case (Case 103 – 100 percent load at 65 °F) represents worst case fumigation impacts, and

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provide the assumptions and data. If the annual average case does not represent the worst case, please provide the worst case fumigation impact analysis, including a discussion of the assumptions and data that support the analysis.

Stanton Energy Reliability Center's Data Request Response, Set 1 (A1-A63), posted on 5/5/17 (TN #217461), provided the following response:

Response: The fumigation analysis was performed using the procedures outlined in Section 4.5.3 of Environmental Protection Agency (EPA) document EPA-454/R-92-019 (EPA, 1992a). The procedure compares the 1-hour concentration results between the fumigation and flat terrain impacts and if the fumigation concentrations are less than the flat terrain impacts, the effects of fumigation may be ignored.

The average annual case (Case 103) does not present the worst-case for fumigation impacts; rather, Case 103 was used in the AFC to determine whether fumigation impacts would need to be assessed. This case was selected as an average condition in order to verify that the fumigation impacts would be less than maximum impacts under normal dispersion conditions (as predicted by AERSCREEN), per the EPA guidance. This would also be expected to occur for the cold day cases (Cases 106 and 108) under partial turbine loads, which were also the screening cases which produced the maximum ground level concentrations.

To verify this, the stack parameters for Cases 106 and 108 were analyzed (Table DRA6-1). The latest versions (16216) of AERSCREEN and MAKEMET, as well as AERMOD (16216r), were used so that separate runs of AERSCREEN were not required to determine impacts under both normal dispersion conditions and fumigation conditions. Results of the two additional cases analyzed are shown below for the same AERSCREEN inputs as used in the previous analysis for a normalized emission rate of one (1) gram/second.

Subsequently, SERC Response Letter, 5/17/17, revised pp. 5.1-29 and 5.1-30 of the Application to incorporate SERC's response to CEC's data request. SERC's revised fumigation analysis indicates an inversion breakup fumigation impact was predicted to occur at between 5,019 to 7,920 meters from the turbine stacks, dependent upon the operating case. Only short-term averaging times were evaluated for three operating cases (as fumigation impacts are generally expected to occur for 90-minutes or less). Revised *Table 5.1-24—Fumigation Impact Summary* compares the unitized fumigation impacts with the maximum AERSCREEN impacts for flat terrain. 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 per

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EPA guidance (1992). Further, no pollutant-specific fumigations results are presented because the overall modeling analysis impacts are conservative with respect to fumigation impacts.

From p. 5.1-30 of the SERC Response Letter, 5/17/17, revised *Table 5.1-24* (same as *Table DRA6-1* in SERC’s Response to CEC) is reproduced in the table below.

Table 31--Fumigation Impact Summary by SERC (One Turbine)

	Case 103 Average Ambient Conditions, 100% Load		Case 106 Cold Ambient Conditions, 100% Load		Case 108 Cold Ambient Conditions, 20% Load	
Averaging Time (Unitized Impacts for 1 g/s)	AERSCREEN Fumigation Impacts (µg/m3)	AERSCREEN Flat Terrain Impacts (µg/m3)	AERSCREEN Fumigation Impacts (µg/m3)	AERSCREEN Flat Terrain Impacts (µg/m3)	AERSCREEN Fumigation Impacts (µg/m3)	AERSCREEN Flat Terrain Impacts (µg/m3)
1-hour	2.465	5.032	2.436	4.914	4.542	23.71
3-hour	2.465	5.032	2.436	4.914	4.542	23.71
8-hour	2.219	4.529	2.192	4.422	4.088	21.33
24-Hour	1.479	3.019	1.461	2.948	2.725	14.22
Distance (m)	7,850	213	7,920	216	5,019	64

PRDAS staff reviewed the applicant’s revised fumigation analysis and provided the following comments and analysis: Since the proposed project occurs in an area where nocturnal radiation inversions are broken up by solar warming near the surface, inversion break-up impacts from the project were analyzed. During these short term events, the maximum impacts could be higher than predicted by AERMOD for normal operation. SERC’s revised fumigation analysis evaluated inversion break-up for 1-hour NO₂, 1-hour, 3-hour, and 24 hour SO₂, 1-hour and 8-hour CO, 24-hour PM₁₀, and 24-hour PM_{2.5}. Because this meteorological phenomena does not persist for long periods, only the shorter averaging periods, less than or equal to 8 hours should be considered. AERSCREEN (version 16216) was utilized for the revised analysis. The modeling parameters for the worst-case operating scenarios were used for each of the modeled pollutants and averaging times. AERSCREEN is the model EPA recommends to analyze impacts from inversion break-up and shoreline fumigation. However, AERSCREEN cannot provide results that correspond to the federal ambient air quality standards for NO₂ and SO₂, due to the form of those standards. For these pollutants, the maximum value is reported in the table below instead of the 98th or 99th percentile, respectively. Because AERSCREEN can only be run with one emission source, the total project impacts were determined by adding the impacts from the two turbines.

PRDAS staff provided pollutant-specific fumigations results shown in the table below. The reason for the additional analysis is that the inversion break-up impacts were found to occur 5 – 7 km away from the facility and were slightly higher than normal operation impacts at that distance. PRDAS staff’s table shows that the inversion break-up impacts, combined with background concentrations, are below the applicable ambient air quality standards.

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**Table 32—Impacts during Normal Operations for Inversion Break-up –
Total Project (Two Turbines)**

Pollutant	Averaging Period	Maximum Modeled Concentration ($\mu\text{g}/\text{m}^3$)	Background Concentration ($\mu\text{g}/\text{m}^3$) ^a	Total Concentration ($\mu\text{g}/\text{m}^3$)	State Standard CAAQS ($\mu\text{g}/\text{m}^3$)	Federal Standard NAAQS ($\mu\text{g}/\text{m}^3$) ^b	Exceeds Any Threshold?
NO ₂	1-hour	2.2	152.3	154.5	339	-	No
SO ₂	1-hour	0.6	23.1	23.7	655	-	No
	3-hour	0.6	23.1	23.7	--	1,300	No
CO	1-hour	2.7	3910.0	3912.7	23,000	40,000	No
	8-hour	2.4	2990.0	2992.4	10,000	10,000	No

^a Maximum values for CO and NO₂ are from SRA 17, Central Orange County (No. 3167) monitoring station and SO₂ from SRA 18, North Coastal Orange County (No. 3195) monitoring station for the last three years (2014 – 2016) was used.

^b Both the California and Federal AAQS values listed are not to be exceeded. The federal NO₂ and SO₂ standards cannot be evaluated with AERSCREEN due to the form of those standards and are not considered in this analysis.

NORMAL OPERATION IMPACTS

Turbine emission rates and stack parameters, such as exit velocity and exit temperature, exhibit some variation with ambient temperature and operating load. Therefore, to evaluate the worst-case impacts, a dispersion modeling analysis was performed at three different load scenarios at three ambient temperature conditions for the two turbines. The two turbines are identical and there are no other equipment with emissions to be considered during facility operations.

The load scenarios (20-21%, 50%, and 100%) and ambient temperatures (40 °F, 65 °F, and 102.7 °F) for a total of nine cases (Cases 100-108) are summarized in *Table 7--Turbine Operating Scenarios*, above. 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 turbine load/temperature screening analysis are set forth in *Table 5.1B-4—Facility Impact/Model Results Summary* that was revised for the SERC Response Letter, 5/17/17.

1. Modeled Emission Rates and Stack Parameters – Normal Operation

The SERC Response Letter, 5/17/17, provided a revised *Chapter 5.1—Air Quality*. On p. 5.1-26, revised *Table 5.1-20—Worst-Case Stack Parameters and Emission Rates* is stated to summarize the turbine operating conditions (stack height, stack temperature, exit velocity, stack diameter, and emission rates) that produced the worst-case impacts for each pollutant and averaging period for (1) normal operating conditions not including start/shutdown periods, (2) normal operating conditions including startup/shutdown periods, and (3) commissioning activities. As explained below, not all the case numbers, associated turbine operating conditions, and emission rates in revised *Table 5.1-20* are correct.

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Table 33—Modeled Emission Rates – Normal Operation, below, supersedes the information provided in revised *Table 5.1-20*. The worst-case modeling scenarios provided in *Table 33* are from an e-mail from Greg Darvin, Atmospheric Dynamics, dated 7/11/17. These scenarios present the scenarios that result in the maximum modeled impacts. All pollutant concentrations were the highest for the minimum load case at 40 °F (Case 108), except for 3- and 24-hour SO₂ which were highest for the maximum load case at 40 °F (Case 106).

Mr. Darvin clarified that, for revised *Table 5.1-20*, the “Normal Operating Conditions” results for 1-hour and 8-hours averaging periods include normal operations only and do not include start-ups and shutdowns. The results are applicable to SO₂ emissions as the normal operations emissions are the same as start-up and shutdown emissions. The “Start-up/Shutdown Periods” results for 1-hour and 8-hour averaging periods include normal operation, startups and shutdowns. These results are applicable to NO_x and CO emissions.

Mr. Darvin clarified that the *Short-Term Emissions* table, that was revised for the SERC Response Letter, 5/17/17, provides the worst-case emissions scenarios, which is relevant to emissions calculations but not modeling. These scenarios present maximum emissions, all of which occur at maximum load case at 40 °F (Case 106). The difference between the worst-case modeling scenarios and the worst-case emissions scenarios are the loads.

Mr. Darvin’s e-mail also provided the corresponding emissions per turbine in lbs/hr and g/sec. These emissions rates were verified as consistent with *Table 5.1B-4--Facility Impact/Model Results Summary*, revised for the SERC Response Letter, 5/17/17. *Table 5.1B-4* presents all of the modeling scenarios that were utilized for the project and includes screening and refined results.

The worst-case modeling scenarios are summarized in the table below.

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Table 33--Modeled Emission Rates - Normal Operation

Averaging Time	Worst-case Modeling Scenario	Pollutant	Emissions Per Turbine, lbs/hr (g/s)
1-hour	NO ₂ : Two turbines complete two starts, two shutdowns and balance of hour at minimum load for 40 °F ambient temperature (Case 108). CO: Two turbines complete two starts, two shutdowns and balance of hour at minimum load for 40 °F ambient temperature (Case 108). SO ₂ : Two turbines at minimum load for 40 °F ambient temperature (Case 108).	NO ₂	6.72 (0.8467)
		CO	8.08 (1.018)
		SO ₂	0.384 (0.0484)
1-hour (federal)	NO ₂ : Two turbines complete two starts, two shutdowns and balance of hour at minimum load for 40 °F ambient temperature (Case 108). SO ₂ : Two turbines at minimum load for 40 °F ambient temperature (Case 108).	NO ₂	6.72 (0.8467)
		SO ₂	0.384 (0.0484)
3-hour	SO ₂ : Two turbines continuous maximum load operation, 40 °F ambient temperature (Case 106).	SO ₂	1.02 (0.1284)
8-hour	CO: Two turbines complete 4 starts, 4 shutdowns, and balance of period at minimum load, 40 °F ambient temperature (Case 108).	CO	5.75 (0.7240)
24-hour	PM ₁₀ , PM _{2.5} : Two turbines continuous minimum load operation, 40 °F ambient temperature (Case 108). SO ₂ : Two turbines continuous maximum load operation, 40 °F ambient temperature (Case 106).	PM ₁₀ , PM _{2.5}	3.00 (0.3780)
		SO ₂	1.02 (0.1284)
Annual	NO ₂ : Two turbines operate at minimum load for 430 normal operating hours, 500 starts, and 500 shutdowns, for total of 638 hours, 65 °F ambient temperature (Case 105). PM ₁₀ , PM _{2.5} : Two turbines operate at minimum load for 901.5 normal operating hours, 1 start, and 1 shutdown, for total of 902 hours, 65 °F ambient temperature (Case 105).	NO ₂	0.4463 (0.0562)
		PM ₁₀ , PM _{2.5}	0.3094 (0.0390)

For the table below, the case numbers are from the table above, which are based on information provided by Mr. Darwin. The corresponding exhaust temperatures and exhaust velocities are from revised *Table 5.1B-4*.

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Table 34--Modeled Stack Parameters - Normal Operation

		Stack Diameter (m)	Stack Height (m)	Exhaust Temp (°K)	Exhaust velocity (m/s)	Case
NO ₂	1-hour	3.6696	21.549	623.24	14.835	108
	1-hour (federal)	3.6696	21.549	623.24	14.835	108
	Annual	3.6696	21.549	656.05	14.742	105
CO	1-hour	3.6696	21.549	623.24	14.835	108
	8-hour	3.6696	21.549	623.24	14.835	108
SO ₂	1-hour	3.6696	21.549	623.24	14.835	108
	1-hour (federal)	3.6696	21.549	623.24	14.835	108
	3-hour	3.6696	21.549	714.73	27.680	106
	24-hour	3.6696	21.549	714.73	27.680	106
PM ₁₀ , PM _{2.5}	24-hour	3.6696	21.549	623.24	14.835	108
	Annual	3.6696	21.549	656.05	14.742	105

2. Modeled Results –Normal Operation for SERC

The applicant provided a modeling analysis of maximum operational impacts for the entire project (two turbines). The applicant correctly included startups and shutdowns for the turbines. Given the number of startups and shutdowns, the emissions from these events cannot be considered as intermittent, as described in the US EPA’s memo dated 3/1/2011. Because the South Coast Air Basin is designated non-attainment for the state PM₁₀ standard, and state and federal PM_{2.5} standards, project increments are compared to the significant change thresholds in Rule 1303.

The maximum operational impacts are presented in *Table 5.1-22—Air Quality Impact Results—Ambient Air Quality Standards*, revised for the SERC Response Letter, 5/17/17. As discussed above, the “Normal Operating Conditions” results include normal operations only and the “Start-up/Shutdown Periods” results include normal operation, startups and shutdowns. Since startup emissions for SO₂ and PM₁₀/PM_{2.5} would be less than during normal operations, the short-term impacts analyses for these pollutants did not include start-up conditions. Since commissioning activities would occur for less than 100 hours for each turbine and only occur during a single year, it was not considered in the 1-hour NO₂ NAAQS modeling analyses per EPA guidance due to the statistical nature of this standard but commissioning activities, discussed below, were assessed for the 1-hour NO₂ CAAQS.

PRDAS staff reviewed the applicant’s analysis and determined the maximum predicted impacts are correct. PRDAS provided updated background concentrations (2014-2016), which are incorporated in the table below. 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 maxim modeled concentrations are below the Rule 1303 thresholds.

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Table 35—Impacts during Normal Operation – Total Project (Two Turbines)

Attainment Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m ³)	Background Concentration ^a (µg/m ³)	Total Concentration (µg/m ³)	State Standard CAAQS ^b (µg/m ³)	Federal Standard, NAAQS ^b (µg/m ³)	Exceeds Any Threshold?
NO ₂	1-hour ^c	6.2	146.6	152.8	339	--	No
	1-hour (98 th percentile) ^c	2.5	111.4	113.9	--	188 ^d	No
	Annual ^c	0.02	50.8	50.82	57	100	No
SO ₂	1-hour	0.4	23.1	23.5	655	--	No
	1-hour (99 th percentile)	0.4	23.1	23.5	--	196 ^e	No
	3-hour	0.3	23.1	23.4	--	1,300	No
	24-hour	0.07	3.7	3.77	105	--	No
CO	1-hour	9.3	3565.0	3574.3	23,000	40,000	No
	8-hour	2.2	2530.0	2532.2	10,000	10,000	No
PM ₁₀	24-hour	0.5	95	95.5	--	150 ^f	No
Non-Attainment Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m ³)	State Standard CAAQS ^b (µg/m ³)	Federal Standard, NAAQS ^b (µg/m ³)	Rule 1303 Thresholds ^g (µg/m ³)	Exceeds Any Threshold?	
PM ₁₀	24-hour	0.5	50	-	2.5	No	
	Annual	0.02	20	-	1	No	
PM _{2.5}	24-hour (98 th percentile)	0.5	-	35	2.5	No	
	Annual	0.02	12	12	1	No	

^a Maximum values for CO, NO₂, and PM₁₀ from SRA 17, Central Orange County (No. 3167) monitoring station and SO₂ from SRA 18, North Coastal Orange County (No. 3195) monitoring station for the last three years (2014-2016) was used.

^b Both the California and Federal AAQS values listed are not be exceeded, except otherwise noted.

^c The conversion of NO_x to NO₂ was implemented using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual concentrations.

^d On April 12, 2010, the US 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.

^e On June 2, 2010, the US 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.

^f Effective July 26, 2013, the South Coast Air Basin has been re-designated to attainment for the federal 24-hour PM₁₀ AAQS.

^g The South Coast Air Basin is designated non-attainment for the state PM₁₀ standards, and state and federal PM_{2.5} standards; therefore, project increments are compared to the significant change thresholds in Rule 1303.

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COMMISSIONING IMPACTS

The NO_x, CO, and VOC emission rates are expected to be higher during the commissioning period than during normal operations, because the turbines are operated without, or with partial, emission control systems in operation. The PM₁₀/PM_{2.5} and SO₂ emission rates are the same as during normal operation, because these pollutants are not controlled by the SCR/CO catalysts.

The commissioning activities for the combustion turbine are expected to consist of six steps to take place during the first year of operation. Commissioning activities will be limited to 100 hours for each turbine, and each turbine will be limited to ~~38~~ 20 hours without emission control systems in operation by condition E193.3. Commissioning is a once-in-a lifetime event.

The *Commissioning Emissions (per Turbine)* table revised for the SERC Response Letter, 5/17/17, shows decreased average emission rates for NO_x and CO for some of the phases, and a decrease in total commissioning emissions for NO_x and CO, relative to the rates and total emissions provided in the Application for which the modeling had been prepared. Nevertheless, the worst-case short-term NO_x and CO commissioning emissions remain 42.81 lbs/hr/turbine and 55.30 lbs/hr/turbine, respectively, and would occur prior to the installation of the catalyst. Short-term SO₂ and PM₁₀/PM_{2.5} emissions during commissioning activities will be the same as for normal operations. The annual emissions for the first year (commissioning and normal operations) and for subsequent years (normal operations) will be subject to the same annual emission limits. Therefore, annual impacts for the commissioning year are not required to be evaluated because annual emissions during the commissioning year can be no higher than those during a subsequent noncommissioning year.

The stack parameters, case, and emission rates are from *Table 5.1-20*, revised for the SERC Response Letter, 5/17/17. The conservative assumption is that the two turbines would be commissioned simultaneously.

Table 36--Modeled Emission Rates and Stack Parameters – Commissioning

		Stack Diameter (m)	Stack Height (m)	Exhaust Temp (°K)	Exhaust velocity (m/s)	Case	Emission Rates per Turbine
NO ₂	1-hour	3.6696	21.549	623.24	14.835	108	42.81 lb/hr = 5.3941 g/sec
CO	1-hour	3.6696	21.549	623.24	14.835	108	55.3 lb/hr = 6.9678 g/sec
	8-hour	3.6696	21.549	623.24	14.835	108	55.3 lb/hr = 6.9678 g/sec

The worst case short-term modeled concentrations during the commissioning process are provided in *Table 5.1-23—Commissioning Air Quality Impact Results*, revised for the SERC Response Letter, 5/17/17. The analysis is based on the two turbines simultaneously undergoing commissioning activities with the highest unabated emissions. As noted above, since the commissioning activities will occur for less than

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200 hours total for both turbines, commissioning impacts were not assessed for the 1-hour NO₂ NAAQS per EPA guidance.

PRDAS staff reviewed the applicant’s analysis and determined the maximum modeled concentrations are correct. PRDAS provided updated background concentrations (2014-2016), which are incorporated in the table below. The maximum modeled concentrations, combined with background concentrations, are below the applicable ambient air quality standards.

Table 37--Impacts during Commissioning - Total Project (Two Turbines)

Attainment Pollutant	Averaging Period	Maximum Modeled Concentration (µg/m ³)	Background Concentration (µg/m ³) ^a	Total Concentration (µg/m ³)	State Standard CAAQS (µg/m ³) ^b	Federal Standard NAAQS (µg/m ³) ^b	Exceeds Any Threshold?
NO ₂ ^c	1-hour	39.5	146.6	186.1	339	- ^d	No
CO	1-hour	63.8	3,565.0	3628.8	23,000	40,000	No
	8-hour	21.3	2530.0	2551.3	10,000	10,000	No

- ^a Maximum values for NO₂ and CO from SRA 17, Central Orange County (No. 3176) monitoring station for the last three years (2014 – 2016) was used.
- ^b Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted.
- ^c The conversion of ambient NO_x to NO₂ was implemented using the Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual concentrations.
- ^d On April 12, 2010, the USEPA established a new 1-hour 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 US 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.

- **Rule 1303(b)(2)—Offsets**

Rule 1303(b)(2) requires a net emission increase in emissions of any nonattainment air contaminant (NO_x, VOC, PM₁₀, and SO_x) from a new or modified source to be offset unless exempt from offset requirements pursuant to Rule 1304. Since CO is an attainment pollutant and not a precursor to any nonattainment pollutant, offset requirements are not applicable.

“Source” is defined by Rule 1302(ao) to mean “any permitted individual unit, piece of equipment, article, machine, process, contrivance, or combination thereof, which may emit or control an air contaminant. This includes any permit unit at any non-RECLAIM facility....”

Unless exempt from offset requirements pursuant to Rule 1304, the amount of offsets required for each pollutant is determined using the 30-day average. The 30-day average is based on the highest emissions for any month, including a month where commissioning takes place. The offset ratio for emission reduction credits (ERCs) is 1.2-to-1.

As discussed below, SERC is exempt from providing offsets pursuant to Rule 1304(d)(1)(A), which is reproduced below.

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- **Rule 1304--Exemptions**

- (d) Facility Exemption

- (1) New Facility

- (A) Any new facility that has a potential to emit less than the amounts in Table A shall be exempt from Rule 1303(b)(2).

- (B) Any new facility that has a potential to emit equal to or more than the amounts in Table A shall offset the total amount of emission increase pursuant to Rule 1303 (b)(2).

TABLE A

<u>Pollutant</u>	<u>Emissions in Tons per Year</u>
Volatile Organic Compounds (VOC)	4
Nitrogen Oxides (NO _x)	4
Sulfur Oxides (SO _x)	4
Particulate Matter (PM ₁₀)	4
Carbon Monoxide (CO)	29

Note: Offsets are no longer required for CO because it is an attainment pollutant.

As shown in *Table 27--Facility Maximum Annual Emissions*, above, the facility maximum emissions for NO_x (3.92 tpy), VOC (1.72 tpy), PM₁₀ (2.70 tpy), and SO_x (0.3 tpy) for the two turbines are all less than 4 tpy, the threshold for requiring offsets.

Condition A63.2 will limit the annual emission limits for NO_x, CO, VOC, PM₁₀, and SO_x, based on the total combined emissions from both turbines (D1 and D7), to 7848 lb/yr NO_x, 9143 lb/yr CO, 3432 lb/yr VOC, 5412 lb/yr PM₁₀, and 595 lb/yr SO_x. Annual limits to stay under the Rule 1304(d)(1)(A) offset exemption thresholds are to be bubbled over all equipment that emit the specific air pollutants.

- **Rule 1303(b)(3)-Sensitive Zone Requirements**

This rule provides that emission reduction credits shall be obtained from the appropriate trading zone. SERC is exempt from providing offsets for this project pursuant to Rule 1304(d)(1)(A), but is expected to be in compliance with this rule if emission reduction credits are required for any future project.

- **Rule 1303(b)(4)-Facility Compliance**

SERC is expected to comply with all applicable rules and regulations of the District, as required by this rule.

- **Rule 1303(b)(5)-Major Polluting Facilities**

Any new major polluting facility shall comply with the following provisions, Rule 1303(b)(5)(A) – (b)(5)(D). As shown in *Table 29—New Source Review Major Polluting Facility Applicability*,

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above, the SERC will not be a major polluting facility and thus will not be subject to Rule 1303(b)(5)(A) – (b)(5)(D), as described below.

- **Rule 1303(b)(5)(A) – Alternative Analysis**
- **Rule 1303(b)(5)(D) – 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. As a minor (non-major polluting) facility, SERC will not be subject to these SCAQMD requirements.

As discussed above, the CEC is the lead agency for licensing the SERC under CEQA and has a certified regulatory program under CEQA. The certified program requires an environmental analysis of the project, including an analysis of alternatives and mitigation measures to minimize any significant adverse effect the project may have on the environment.

- **Rule 1303(b)(5)(B) – 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. As a minor (non-major polluting) facility, SERC will not be subject to this provision.
- **Rule 1303(b)(5)(C) – 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 PM₁₀ or 40 tpy of NO_x; 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. As a minor (non-major polluting) facility for which the net emission increases do not exceed 15 tpy of PM₁₀ or 40 tpy NO_x, SERC 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

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Analysis:

Turbines

BACT--Conditions A195.1, A195.2, and A195.3 set forth the BACT limits for NO_x, CO, and VOC, respectively.

Monthly Emissions--Condition A63.1 sets forth the monthly limits for NO_x, CO, VOC, PM₁₀, PM_{2.5}, and SO_x.

Selective Catalytic Reduction Systems

BACT—Condition A195.4 sets forth the BACT limit for the ammonia slip.

Monthly Emissions—Monthly emission limits are applicable to basic equipment, such as the turbines, not to control equipment.

Ammonia Tank

BACT—Condition C157.1 requires the tank to be equipped with a pressure relief valve set at 2.5 psig. Condition E144.1 requires the tanks to be vented, during filling, to the vessel from which it is being filled.

Monthly Emissions—The pressure relief valve and vapor return line will result in no ammonia emissions emitted from the tank under normal operations.

Rule 1325—Federal PM_{2.5} New Source Review Program

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.

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The relevant provisions of Rule 1325, as amended 11/4/16, 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 PM_{2.5} 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}....

- (b) **Definitions**
For the purposes of this rule, the definitions in Title 40 CFR 51.165(a)(1), as it exists on November 4, 2016 shall apply, unless the same term is defined below, then the defined term below shall apply:

- (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 the following levels:
 - (A) 100 tons per year per pollutant until August 14, 2017 or until the effective date of U.S. EPA’s approval of the November 4, 2016 amendments to this rule, whichever is later; and,
 - (B) 70 tons per year per pollutant after August 14, 2017 or upon the effective date of U.S. EPA’s approval of the November 4, 2016 amendments to this rule, whichever is later.

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.

- (8) **PRECURSORS** means, for the purposes of this rule, nitrogen oxides (NO_x) and sulfur dioxide (SO₂), and, effective August 14, 2017 or the effective date of U.S. EPA’s approval of the November 4, 2016 amendments to this rule, whichever is later, Volatile Organic Compounds (VOC), and Ammonia.

- (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:

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- (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 NO_x and SO₂ 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:

According to the U.S. EPA website, Rule 1325, amended 11/4/16, is not SIP-approved as of 12/12/17.

(<https://yosemite.epa.gov/R9/r9sips.nsf/Agency?ReadForm&count=500&state=California&cat=South+Coast+Air+Quality+Management+District-Agency-Wide+Provisions>)

As SIP-approval is expected, the applicability analysis summarized in the table below assumes the most recent amendment is SIP-approved and the major source threshold is 70 tpy for this rule. PM_{2.5} emissions are conservatively assumed to be the same as PM₁₀ emissions.

Table 38 – Rule 1325 Applicability

	NO _x	SO ₂	VOC	NH ₃	PM _{2.5}
Stanton Electric Reliability Center (SERC) Potential to Emit, TPY (<i>Table 27—Facility Maximum Annual Emissions</i>)	3.92	0.3	1.72	2.98	2.70
Major Source for 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.
Rule 1325 Applicable?	No	No	No	No	No

Rule 1325 is not applicable to NO_x, SO₂, VOC, NH₃, and PM_{2.5} because the potential to emit (PTE) for each of these pollutants is less than 70 tpy.

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Rule 1401—New Source Review of Toxic Air Contaminants, as amended 9/1/17

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.

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 (1.0×10^{-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.

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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.

The applicant provided health risk assessment (HRA) modeling using the California Air Resources Board's (ARB) *Hot Spots Analysis Reporting Program* (HARP 2, version 16217), which incorporates methodology presented in the 2015 OEHHA Guidelines. The SCAQMD HRA procedures require HARP to be used in Tier 4 risk assessments.

- Turbines
SERC Response Letter, 10/31/17, provided a final revised *Table 5.9-8-SERC HRA Summary* table. The revised HRA results were based on SCAQMD-approved emission factors and control efficiencies for the toxic emissions, which are summarized in *Table 24--Toxic Air Contaminants/Hazardous Air Pollutants per Turbine*, above. As SERC provided HRA results for only the project in revised *Table 5.9-8*, the PRDAS staff provided an independent health risk analysis for each turbine, as well as for the project (two turbines), in their modeling review memo, dated 11/29/17.

The following modeled stack parameters for the hourly and annual impacts are from an e-mail, dated 7/13/17, from Greg Darwin.

Table 39--Modeled Stack Parameters for HRA for a Turbine

Parameter	Hourly Impacts (Case 103--65.0 °F, Maximum Load)	Annual Impacts (Case 103—65.0 °F, Maximum Load)
Stack Diameter (m)	3.6698	3.6698
Stack Height (m)	21.549	21.549
Stack Temp (°K)	721.56	721.56
Stack Velocity (m/s)	27.097	27.097

The maximum hourly turbine impacts for the turbines were predicted using the exhaust parameters for the 65.0 °F, maximum load case, which represents the turbine exhaust parameters associated with the maximum predicted 1-hour ground-level impact in the dispersion modeling (Case 103 in *Table 7—Turbine Operating Scenarios*). The annual turbine impacts were also predicted for the 65.0 °F, maximum load case, which represents the average annual temperature and load scenario resulting in the maximum predicted annual ground-level impact in the dispersion modeling (Case 103).

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The PRDAS staff provided the following health risk impacts for each permit unit (turbine), as required by Rule 1401. The maximum individual cancer risks (MICR) and noncancer acute and chronic hazard indices are below the respective health risk standards.

Table 40—Health Risk Impacts - Turbines No. 1 & No. 2

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Turbine No. 1							
Sensitive	0.03 in one million (0.028 E-06)	0.00004	0.000831	Ten in one million ^a (10.0 E-06)	1.0	1.0	No
Worker	0.001 in one million (0.000943 E-06)	0.0000437	0.000954	Ten in one million ^a (10.0 E-06)	1.0	1.0	No
Turbine No. 2							
Sensitive	0.03 in one million (0.028 E-06)	0.0000399	0.000561	Ten in one million ^a (10.0 E-06)	1.0	1.0	No
Worker	0.001 in one million (0.00106 E-06)	0.0000492	0.000829	Ten in one million ^a (10.0 E-06)	1.0	1.0	No

^a 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 x 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 x 10⁻⁵).

- Project**

The project health risk assessment is provided in support of the CEC’s CEQA analysis. PRDAS Staff reviewed the applicant’s health risk assessment for the project by independently performing a health risk assessment. The results provided by PRDAS staff show minor differences from the applicant’s results. The reason is that PRDAS staff set the dermal climate to “mixed,” as currently recommended by the SCAQMD Risk Assessment Procedure for Rules 1401 and 212, instead of “warm,” as set by SERC. The maximum individual cancer risks (MICR) and noncancer acute and chronic hazard indices are below the applicable health risk standards.

Table 41 – Health Risk Impacts – Total Project (Two Turbines)

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Sensitive	0.06 in one million (0.0557 E-06)	0.0000793	0.0016	Ten in one million ^a (10.0 E-06)	1.0	1.0	No
Worker	0.002 in one million (0.00201 E-06)	0.000093	0.00171	Ten in one million ^a (10.0 E-06)	1.0	1.0	No

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- Best Available Control Technology For Toxics (T-BACT) for Combustion Turbines
The *Overview of the SCAQMD Best Available Control Technology Guidelines*, amended December 2016, 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 simple-cycle 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 O₂. 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

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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, such as the proposed turbines for SERC, 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 SERC will not be a major source for HAP emissions.

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

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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 NO₂, SO₂, and CO emissions. In addition, effective 7/26/13, the SCAB has been redesignated to attainment for the 24-hour PM₁₀ national ambient air quality standard. Therefore, the attainment air contaminants are NO₂, SO₂, CO, and PM₁₀.

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 µg/m³, (24-hours average).

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Rule 1702--Definitions

(m) “Major Stationary Source” means: “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.”

Rule 1706—Emissions Calculations

This rule shall be used as the basis for calculating applicability to Regulation XVII as delineated in Rule 1703(a).

Rule 1706(c) provides the method for calculating the emission increases and reductions associated with a stationary source.

(c)(1)(A) The emissions for new permit units shall be calculated as the potentials to emit.

• **PSD Applicability Analysis for Criteria Pollutants:**

The District is presently in attainment for the primary NAAQS for NO₂, SO₂, CO, and PM₁₀. For a proposed new source, PSD applies to each regulated pollutant 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. The twenty-eight source categories subject to the 100 tpy threshold are listed in Rule 1702(m)(1). A source category subject to the 100 tpy threshold is a “fossil fuel-fired steam electric plants of more than 250 million BTU/hr,” but this refers to a combined cycle plant, not a simple cycle plant like SERC. Thus the 250 tpy threshold limit is applicable to SERC.

The following table summarizes the Rule 1701(b)(2)(A) analysis to determine which pollutants, if any, are subject to PSD review.

Table 42 – Prevention of Significant Deterioration Applicability

	NO_x	PM₁₀	SO_x	CO
Stanton Electric Reliability Center (SERC) Potential to Emit, TPY (<i>Table 27—Facility Maximum Annual Emissions</i>)	3.92	2.70	0.3	4.58
Major Stationary Source?	No, potential to emit is less than 250 tpy.	No, potential to emit is less than 250 tpy.	No, potential to emit is less than 250 tpy.	No, potential to emit is less than 250 tpy.
PSD Applicable?	No	No	No	No

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As shown in the table above, SERC is not subject to PSD review for NO_x, PM₁₀, SO_x, and CO because the potentials to emit for these attainment pollutants do not exceed the applicability thresholds of 250 tpy.

As discussed above for *Regulation XIII—New Source Review (NSR)*, Rule 1303(a)(1) requires minor source BACT for the non-attainment pollutants, NO_x, PM₁₀/PM_{2.5}, SO₂, VOC, and ammonia. (Since NO_x, SO_x, and VOC are precursors to non-attainment pollutants, they are treated as non-attainment pollutants, as well.) For *Regulation XVII – Prevention of Significant Deterioration*, 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.” As explained in the SCAQMD Staff Report for Regulation XVII dated September 28, 1988 for the October 7, 1988 Board meeting, the BACT requirement is applicable to all permit units regardless if the source is classified as a minor or major facility. Thus, Rule 1701(b)(1) requires minor source BACT for the attainment pollutant, CO.

Rule 1701(b)(1) does not require the attainment pollutants, NO_x, PM₁₀, SO_x, and CO, to be subject to BACT for PSD pollutants, because SERC is not subject to PSD review for these pollutants. As reference, BACT for PSD pollutants is defined in 40 CFR 52.21(b)(12) as: "an emissions limitation...based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 [New Source Performance Standards (NSPS)] and 61 [NESHAPS]...." EPA outlined the process used to perform the case-by-case analysis, called a Top-Down BACT analysis, in a June 13, 1989 memorandum. The top-down analysis method was further discussed in the EPA’s New Source Review Workshop Manual, October 1990. The five-step top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked (“top”) option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not “achievable” in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT. This top-down BACT analysis for PSD is not applicable to the SERC.

Rule 1714 – Prevention of Significant Deterioration for Greenhouse Gases

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

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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 (CO₂), nitrous oxide (N₂O), methane (CH₄), 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.

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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 is required for SERC because it will be subject to the Acid Rain Program.)

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

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determined that SERC is not otherwise subject to PSD for CO, NO_x, SO₂, or PM₁₀. Therefore, SERC is not subject to PSD requirements for GHG, regardless of the GHG potential emissions. Further, even if SERC were subject to PSD for CO, NO_x, SO₂, or PM₁₀, the GHG potential emissions of 49,486 tpy CO₂e is less than the 75,000 tons per year applicability threshold for GHG PSD. As SERC 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 2001--Applicability**

- (b) Criteria for Inclusion in RECLAIM

The Executive Officer will maintain a listing of facilities which are subject to RECLAIM. The Executive Officer will include facilities, unless otherwise exempted pursuant to subdivision (i), if emissions fee data for 1990 or any subsequent year filed pursuant to Rule 301 – Permit Fees, shows four or more tons per year of NO_x of SO_x emissions....

The facility has requested a 4 tpy annual NO_x limit to stay out of RECLAIM. As shown in *Table 27--Facility Maximum Annual Emissions*, above, the facility maximum emissions for NO_x is 3.92 tpy (7848 lb/yr). Condition A63.2 will limit the annual emission limits for NO_x, based on the total combined emissions from both turbines (D1 and D7), to 7848 lb/yr NO_x.

Regulation XXX—Title V Permits

- **Rule 3001--Applicability**

SERC is a new facility for which an initial Title V facility permit is required pursuant to Rule 3001(c)(3). Paragraph (c)(3) specifies applications are required to be submitted to obtain Title V permits for: “All ‘affected source’ as defined under the acid rain provisions of Title IV of the federal Clean Air Act and 40 CFR Part 70, Section 70.2.”

- **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;

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- (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.

The SCAQMD will follow all public participation requirements set forth in Rule 3006 because this permit will be the Initial Title V permit for this facility. Pursuant to Rule 212(h), the SCAQMD may combine public notices to avoid duplication provided that all required public notice requirements are satisfied. The Rule 3006 Title V public notice will be combined with the Rule 212(c)(2) public notice for a single public notice. (The Rule 212 public notice requirements and completion are discussed above under Rule 212-Standards for Approving Permits.) 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., The Register.

Pursuant to Rule 3006(a)(1)(F), any person may request a proposed permit hearing on this application for an initial Title V permit 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 extended so that the deadline falls on an SCAQMD business day to allow commenters access to SCAQMD staff on the end date.

As discussed above under Rule 212, Rule 212(d) requires the applicant to distribute the public notice to each address within a ¼- mile radius of the project. The distributed public notice will state that comments must be received within 33 days of the date of distribution of this notice in order to allow a full 30-day comment period required by Rule 212(g)(4) and Rule 3006(a)(1)(D). In addition, the distributed public notice will state that the hearing request must be received within 18 days of the date of distribution of this notice in order to allow a full 15-day request period required by Rule 3006(a)(1)(F). If the public comment or hearing request end date falls on a Saturday, Sunday, or Monday, the end date is extended so that the deadline falls on an SCAQMD business day to allow commenters access to SCAQMD staff on the end date.

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Pursuant to Rule 3003(j), the proposed permit for initial permit 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.

Title V Public Notice Requirements Completion

The "Rule 212 Public Notice Requirements Completion" discussion, above, is incorporated here. As indicated in that discussion, the PDOC (engineering evaluation) and proposed revised Title V permit were issued for review on 2/9/18.

- *Publication of Public Notice*
On 2/14/18, the Notice of Intent to Issue Permits Pursuant to SCAQMD Rules 212 and 3006 was published in The Orange County Register. Pursuant to Rule 3006(a)(1)(F), any person may request a proposed permit hearing on these applications for an initial Title V permit by submitting to the SCAQMD a complete Hearing Request Form (Form 500G) for a proposed hearing by 2/28/18. No Title V Public Hearing requests were received. The public comment period ended on 3/15/18, without any comments submitted.
- *EPA Proposed Initial Permit Issuance Review for Title V*
On 2/9/18, SCAQMD electronically submitted the public notice, PDOC analysis, and proposed initial Title V facility permit to the EPA for the 45-day review. The EPA did not provide comments.
- *Comment Letter(s)*
The only comments received were from SERC in a letter, dated 2/20/18. The SCAQMD provided responses in a letter, dated 4/19/18, which agreed to administrative type changes to permit conditions.
- *EPA Proposed Initial Permit Issuance Review for Title V--Follow-up*
On 4/20/18, SCAQMD electronically resubmitted the proposed permit package that had been submitted on 2/9/18, and added SERC's comment letter and SCAQMD's response letter. On 4/20/18, the EPA responded that it had reviewed the proposed permit package and had not further comments at this time.
- *FDOC Appendix for Comments and SCAQMD Responses*
Appendix B has been added to this FDOC to include the comments received during the comment period, and the SCAQMD's responses to the comments.

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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 H23.1 will require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK (see regulatory analysis below). The condition will include that the operator shall comply with the requirements of §60.7(c), §60.4375, §60.4380, and §60.4395 for reporting excess emissions and monitor downtime.

§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

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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 H23.1 will include that the performance evaluation of the NO_x CEMS shall be conducted as part of the initial performance test of the turbine required no later than 180 days after initial start-up by §60.8, in accordance with the requirements of §60.4405. The initial performance test of the turbine shall be conducted to demonstrate compliance with the §60.4320 limit of 25 ppmv NO_x at 15% O₂.

§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

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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

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- (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 O₂ 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 H23.1 will include that the NO_x CEMS shall comply with the applicable requirements of §60.13, §60.4335(b), §60.4340(b)(1), and §60.4345 for monitoring.

40 CFR 60 Subpart Da—Standards of Performance for Electric Utility Steam Generating Units

§60.40Da(a)(1) & (2)—Except as specified in paragraph (e), the affected facility to which this subpart applies is each electric utility steam generating unit that is capable of combusting more than 73 MW (250 MMBtu/hr) heat input; and for which construction, modification, or reconstruction is commenced after September 18, 1978. This subpart is not applicable to the two simple-cycle turbines, because the turbines do not include any heat recovery steam generators that are fired or equipped with duct burners.

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40 CFR 60 Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

§60.40b(a)—This subpart applies to each steam generating unit that commences construction after June 19, 1984, and that has a heat input capacity from fuels combusted in the steam generating unit of greater than 29 MW (100 MMBtu/hr). This subpart is not applicable because SERC will not include any boilers.

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

Subpart GG establishes requirements for stationary gas turbines with a heat input at peak load equal to or greater than 10 MMBtu/hr (10.7 gigajoules per hour), based on lower heating value, which commences construction, modification, or reconstruction after October 3, 1997 and are not subject to subpart KKKK. Subpart KKKK is applicable to stationary combustion turbines with a heat input greater than 10 MMBtu/hr (10.7 gigajoules per hour), based on higher heating value, which commenced construction, modification or reconstruction after February 18, 2005. The proposed simple-cycle turbines are subject to the requirements of 40 CFR Subpart KKKK, as discussed below, and thus are exempt from the requirements of this subpart per §60.4305(b) of Subpart KKKK.

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: As the applications were submitted on 11/2/16, any construction of the turbines will commence after 2/18/05, the applicability date for this subpart. Thus, this subpart is applicable to the turbines, each rated at 484.2 MMBtu/hr at 40 °F, which is greater than the 10 MMBtu/hr applicability threshold.

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§60.4315 What pollutants are regulated by this subpart?

The pollutants regulated by this subpart are nitrogen oxide (NO_x) and sulfur dioxide (SO₂).

§60.4320 What emission limits must I meet for nitrogen oxides (NO_x)?

- (a) You must meet the emission limits for NO_x 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
New turbine firing natural gas	> 50 MMBtu/h and ≤ 850 MMBtu/h	25 ppm at 15 percent O ₂ or 150 ng/J of useful output (1.2 lb/MWh).

Analysis: Table 1 to Subpart KKKK provides NO_x emission standards based on combustion turbine type and heat input at peak rate. For a new 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 NO_x emission limit is 25 ppmv at 15% O₂. As the turbines are expected to meet the BACT limit of 2.5 ppmv at 15% O₂, compliance with this section is expected. Accordingly, an emissions limit of 25 PPMV NO_x, pursuant to Subpart KKKK, will be included for the turbines on the facility permit in the “Emissions and Requirements” column.

Condition H23.1 will include that the initial performance test of the turbine shall be conducted to demonstrate compliance with the §60.4320 limit of 25.0 ppmv NO_x at 15% O₂, 1-hour averaging. Although Table 1 to Subpart KKKK does not specify the averaging period, the CEMS requirements in §60.4345(b) specifies an 1-hour averaging period.

§60.4330 What emission limits must I meet for sulfur dioxide (SO₂)?

- (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 SO₂ 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 SO₂/J (0.060 lb SO₂/MMBtu) heat input. If your turbine simultaneously fires multiple fuels, each fuel must meet this requirement;

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- (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 SO₂, pursuant to Subpart KKKK, will be included 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 (O₂) or carbon dioxide (CO₂)) monitor, to determine the hourly NO_x emission rate in parts per million (ppm) or

Analysis: The turbines will use water injection and an SCR system to control NO_x emissions. This section applies to older turbines for which only water or steam injection is used, with no additional post-combustion NO_x control.

The turbines are subject to §60.4340, discussed below, which provides continuous compliance requirements if water or steam injection is not [only] used.

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§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 NO_x control is used, in addition to or instead of water or steam injection. As discussed for Subpart A above, condition H23.1 will require the turbines to comply with the applicable requirements of 40 CFR 60 Subpart KKKK. The condition will include that the NO_x CEMS shall comply with the applicable requirements of §60.13, §60.4335(b), §60.4340(b)(1), and §60.4345 for monitoring. 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.

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§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 SO₂ 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.

Analysis: As discussed above for §60.4320(a), condition H23.1 will include that the initial performance test of the turbine shall be conducted to demonstrate compliance with

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the §60.4320 limit of 25.0 ppmv NO_x at 15% O₂, 1-hour averaging. Although Table 1 to Subpart KKKK does not specify the averaging period, the CEMS requirements in §60.4345(b) specifies an 1-hour averaging period.

- (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 SO₂ 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]

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Analysis:

Condition H23.1 will include that the NO_x CEMS shall comply with the applicable requirements of §60.13, §60.4335(b), §60.4340(b)(1), and §60.4345 for monitoring.

Condition H23.2 requires the NO_x CEMS to also meet the applicable requirements of *40 CFR Part 75—Continuous Emission Monitoring [Acid Rain Program]*, discussed below.

§60.4345(a), (c) and (e) provide alternatives to allow a CEMS that complies with specific Part 75 requirements to also meet specific Subpart KKKK requirements.

Note: *40 CFR Subparts A and KKKK do not provide specific requirements for a CEMS certification application. As discussed below, 40 CFR Part 75 provides such requirements in §§75.20, 75.60, and 75.63.*

§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 O₂ concentration exceeds 19.0 percent O₂ (or the hourly average CO₂ concentration is less than 1.0 percent CO₂), a diluent cap value of 19.0 percent O₂ or 1.0 percent CO₂ (as applicable) may be used in the emission calculations.
- (c) Correction of measured NO_x concentrations to 15 percent O₂ 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 SO₂ 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 25 ppm] or the following equation for units complying with the output based standard:

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Analysis:

Condition H23.1 will include that the NO_x CEMS shall comply with the applicable requirements of §60.4350 for identifying excess emissions.

For the purpose of identifying excess emissions for subpart KKKK, §60.4350(c) specifies that correction of measured NO_x concentrations to 15 percent O₂ is not allowed. This requirement is a separate requirement than that listed in condition D82.2, which will require the measured NO_x concentration to be corrected to 15% O₂ to demonstrate compliance with the 2.5 ppm NO_x at 15% O₂ BACT limit, as well as other BACT and offset requirements.

Condition H23.2 requires the NO_x CEMS to also meet the applicable requirements of *40 CFR Part 75—Continuous Emission Monitoring*. §60.4350(d) provides an alternative to allow a CEMS that complies with specific Part 75 requirements to also meet specific Subpart KKKK requirements.

§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 SO₂/J (0.060 lb SO₂/MMBtu) heat input for units located in continental areas and 180 ng SO₂/J (0.42 lb SO₂/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 SO₂/J (0.060 lb SO₂/MMBtu) heat input for continental

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areas and has potential sulfur emissions of less than less than 180 ng SO₂/J (0.42 lb SO₂/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 SO₂/J (0.060 lb SO₂/MMBtu) heat input for continental areas or 180 ng SO₂/J (0.42 lb SO₂/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 H₂S 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 NO_x 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 NO_x CEMS is selected as an alternative to the annual performance tests, pursuant to §60.4340(b)(1).

Condition H23.1 will include that the operator shall comply with the requirements of §60.7(c), §60.4375, §60.4380, and §60.4395 for reporting excess emissions and monitor downtime.

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§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 [25 ppm at 15% O₂]. 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 O₂ 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 H23.1 will include that the operator shall comply with the requirements of §60.7(c), §60.4375, §60.4380, and §60.4395 for reporting excess emissions and monitor downtime.

§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.

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Analysis: Condition H23.1 will include that the operator shall comply with the requirements of §60.7(c), §60.4375, §60.4380, and §60.4395 for reporting excess emissions and monitor downtime.

§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

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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 NO_x performance tests on an annual basis. Pursuant to §60.4340(b)(1), however, the installation of a NO_x CEMS is an alternative to the subsequent performance tests required by §60.4340(a). Therefore, since a NO_x 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 H23.1 will include that the performance evaluation of the NO_x CEMS shall be conducted as part of the initial performance test of the turbine required no later than 180 days after initial start-up by §60.8, in accordance with the requirements of §60.4405. The initial performance test of the turbine shall be conducted to demonstrate compliance with the §60.4320 limit of 25.0 ppmv NO_x at 15% O₂, 1-hour averaging.

The initial performance test for NO_x required by condition H23.1 for the purposes of Subpart KKKK is separate from the initial source test for NO_x, CO, SO_x, VOC, PM₁₀, PM_{2.5} and ammonia (NH₃) required by condition D29.1 for the purposes of BACT and offsets compliance.

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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, 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.

As EPA review is pending, the regulatory analysis is set forth below for the simple-cycle 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 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: Construction for the SERC will commence after January 8, 2014, if the permits are approved.

§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.

- (1) From *Table 7—Turbine Operating Scenarios*, the turbine rating is 422.7 MMBtu/hr (LHV) at 100% load and 65 °F ambient temperature (case 103). The 422.7 MMBtu/hr base load rating is higher than the 250 MMBtu/hr

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threshold. (As §60.5580 defines “*design efficiency*” to mean the rated overall net efficiency on a lower heating value basis at the base load rating at ISO conditions, the base load rating is based on LHV, as well.)

- (2) The turbine generator rating of 47.673 MW-net (case 103) is higher than the 25 MW-net threshold.
- (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).

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- (9) The proposed Washington County EGU project....
- (10) The proposed Holcomb EGU project....

Analysis: The new NSPS is applicable to the proposed simple-cycle turbines, because they do not meet any of the above non-applicability criteria.

- **Applicable Emissions Standards**

The NSPS created three subcategories with different standards for each. These subcategories are base load natural-gas fired units, non-base load natural gas-fired units, and multi-fuel-fired units. The non-base load gas-fired subcategory and associated standard is discussed below.

§60.5520 What CO2 emission standard must I meet?

- (a) For each affected EGU subject to this subpart, you must not discharge from the affected EGU any gases that contain CO2 in excess of the applicable CO2 emission standard specified in Table 1 or Table 2 of this subpart, consistent with paragraphs (b), (c), and (d) of this section, as applicable.

Table 2 of Subpart TTTT of Part 60 – CO2 Emission Standards for Affected Stationary Combustion Turbines That Commenced Construction after January 8, 2014 and Reconstruction after June 18, 2014

Affected EGU	CO2 Emission Standard
Newly constructed or reconstructed stationary combustion turbine that supplies its design efficiency or 50 percent, whichever is less, times its potential electric output or less as net-electric sales on either a 12-operating month or a 3-year rolling average basis and combusts more than 90% natural gas on a heat input basis on a 12-operating month rolling average basis.	50 kg CO2 per gigajoule (GJ) of heat input (120 lb CO2/MMBtu)

§60.5525 What are my general requirements for complying with this subpart?

Compliance with the applicable CO2 emission standard of this subpart shall be determined on a 12-operating-month rolling average basis.

§60.5580 What definitions apply to this subpart?

Design efficiency means the rated overall net efficiency (e.g., electric plus useful thermal output) on a lower heating value basis at the base load rating, at ISO conditions, and at the maximum useful thermal output (e.g., CHP unit with condensing steam turbines would determine the design efficiency at the maximum level of extraction and/or bypass)....

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Potential electric output means 33 percent or the base load rating design efficiency at the maximum electric production rate (e.g., CHP units with condensing steam turbines will operate at maximum electric production), whichever is greater, multiplied by the base load rating (expressed in MMBtu/h) of the EGU, multiplied by 10⁶ Btu/MMBtu, divided by 3,413 Btu/KWh, divided by 1,000 kWh/MWh, and multiplied by 8,760 h/yr (e.g., a 35 percent efficient affected EGU with a 100 MW (341 MMBtu/h) fossil fuel heat input capacity would have a 306,000 MWh 12 month potential electric output capacity).

Analysis: If a turbine operates below the product of the “design efficiency” or 50%, whichever is less, and “potential electric output” on the same basis, the standard is 120 lb CO₂/MMBtu, which is the standard for non-base load natural gas-fired units with a small allowance for distillate oil. This standard is readily achievable because the CO₂ emission rate of natural gas is 117 lb CO₂/MMBtu.

Each turbine will operate on natural gas 100% of the time.

Page 2-34 of the Application indicates the design efficiency is 39 percent on a LHV basis, which is less than 50%. The potential electric output will be calculated using the net MW ratings (case 103), instead of the formula in the definition.

$$\text{Design efficiency} \times \text{potential electric output} = (0.39) * (47.673 \text{ MW-net/turbine}) * (8760 \text{ hr/yr}) = 162,870 \text{ MWh-net/yr}$$

If any simple-cycle turbine generates more electricity than 162,870 MWh-net/yr, it will need to comply with the 1000 lb CO₂/MWh-gross emission limit. For each turbine, the permitted annual net electric sales is 43,859 MWh-net/turbine (calculated as 47.673 MW-net/turbine x 920 permitted hours, including startups and shutdowns). Since the permitted annual net electric sales of 43,859 MWh-net/turbine is less than the potential electric output threshold 162,870 MWh-net/yr, the applicable standard is 120 lb CO₂/MMBtu. As SERC is natural-gas fired only, the turbines are expected to emit CO₂ at a rate at 117 lb CO₂/MMBtu, thereby complying with the 120 lb CO₂/MMBtu standard. The Subpart TTTT requirements are set forth in condition E193.4.

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

This regulation applies to gas turbines located at major sources of HAP emissions. The applicability of federal requirements governing HAPs is dependent on whether a facility is a major source or area source for HAPs. A "major source" means “any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants.” An “area source” means “any stationary source of hazardous air pollutants that is not a major source.”

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Facility

The only equipment emitting HAP emissions are the two turbines. Ammonia and propylene are toxic air contaminants for the purpose of Rule 1401, but not federal hazardous air pollutants. Therefore, the single highest HAP emissions are for formaldehyde.

From *Table 24—Toxic Air Contaminants/Hazardous Air Pollutants per Turbines*, above, the formaldehyde emissions from the two turbines is 0.152 tpy [calculated as (2 turbines) * (0.076 tpy/turbine)]. The total combined HAPs is 0.338 tpy [calculated as (2 turbines) * (0.169 tpy/turbine)].

The total combined formaldehyde emissions from all sources is 0.152 tpy, which is less than 10 tpy. The total combined HAPs from all sources is 0.338 tpy, which is less than 25 tpy. Therefore, the SERC is an area source for HAPS, not a major source. The requirements of this regulation do **not** apply.

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. This rule is intended to provide “reasonable assurance” that the control systems are operating properly to maintain compliance with the emission limits.

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: As shown by *Table 29—New Source Review Major Polluting Facility Applicability*, SERC will not be a major source. Therefore, CAM is not applicable.

40 CFR Part 68—Chemical Accident Prevention Programs

§68.1—This part sets forth the list of regulated substances and thresholds and the requirements for owners or operators of stationary sources concerning the prevention of accidental releases.

§68.10(a)—An owner or operator of a stationary source that has more than a threshold quantity of a regulated substance in a process shall comply with the requirements of this part.

§68.130(a)—Regulated toxic and flammable substances are listed with the associated threshold quantities in Tables 1, 2, 3, and 4 to §68.130. Table 1 to §68.130—List of Regulated Toxic Substances

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and Threshold Quantities for Accidental Release Prevention lists “ammonia (anhydrous)” with a threshold quantity of 10,000 lbs, and “ammonia (conc 20% or greater)” with a threshold quantity of 20,000 lbs.

Analysis: Because the ammonia tank will contain 19% ammonia, not anhydrous ammonia or ammonia with a 20% or greater concentration, Part 68 is not applicable.

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 (SO₂) and nitrogen oxides (NO_x), the primary precursors of acid rain, from the power sector. The SO₂ program sets a permanent cap on the total amount of SO₂ that may be emitted by electric generating units (EGUs) in the contiguous United States. The program was phased in, with the final 2010 SO₂ 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 SO₂ 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, SO₂ allowances under the Acid Rain Program can be bought at EPA’s Annual SO₂ 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

Note: *The following definitions are referenced in the regulatory analysis of subsequent rule sections discussed below.*

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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:

Capacity factor means either:

- (1) The ratio of a unit's actual annual electric output (expressed in MWe/hr) to the unit's nameplate capacity (or maximum observed hourly gross load (in MWe/hr) if greater than the nameplate capacity) times 8760 hours; or
- (2) The ratio of a unit's annual heat input (in million British thermal units or equivalent units of measure) to the unit's maximum rated hourly heat input rate (in million British thermal units per hour or equivalent units of measure) times 8,760 hours.

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 SO₂, NO_x, or CO₂ 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 (CO₂ or O₂) 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 O₂ or CO₂ (% O₂ or CO₂), 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....

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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.

Analysis: The turbines are fired on natural gas only. As discussed under the definition of “pipeline natural gas” below, the regulatory analysis will be based on the more conservative interpretation that the natural gas is “natural gas,” and not “pipeline natural gas.”

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.

Peaking unit means:

- (1) A unit that has:
 - (i) An average capacity factor of no more than 10.0 percent during the previous three calendar years and
 - (ii) A capacity factor of no more than 20.0 percent in each of those calendar years.
- (2) For purposes of part 75 of this chapter, a unit may initially qualify as a peaking unit if the designated representative demonstrates to the satisfaction of the Administrator that the requirements of paragraph (1) of this definition are met, or will in the future be met, through one of the following submissions:

Analysis: Based on a maximum of 902 hours at 100% load, the annual capacity factor is estimated to be 10.3% (902 hr/8760 hr). The 902 hr/yr maximum is from *Table 20—Maximum Annual Emissions per Turbine and Total Project (Two Turbines) and 30-Day Averages per Turbine* (case no. 3), above. A demonstration that the turbines qualify as peaking units can be submitted at the discretion of the designated representative at a later date. This regulatory analysis will be based on the more conservative interpretation that the turbines are not peaking units.

Phase II means the Acid Rain Program period beginning January 1, 2000, and continuing into the future thereafter.

Phase II unit means any affected unit, except an affected unit under part 74 of this chapter, that is subject to an Acid Rain emissions reduction requirement or Acid Rain emissions limitation during Phase II only.

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Pipeline natural gas means a naturally occurring fluid mixture of hydrocarbons (e.g., methane, ethane, or propane) produced in geological formations beneath the Earth's surface that maintains a gaseous state at standard atmospheric temperature and pressure under ordinary conditions, and which is provided by a supplier through a pipeline. Pipeline natural gas contains 0.5 grains or less of total sulfur per 100 standard cubic feet. Additionally, pipeline natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 950 and 1100 Btu per standard cubic foot.

Analysis: The turbines are fired on natural gas only. As discussed above for 40 CFR 60 Subpart KKKK, §60.4365, 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 higher than the 0.5 gr S/100 scf limit for “pipeline natural gas.” This regulatory analysis will be based on the more conservative interpretation that the natural gas is “natural gas,” as defined above, and not “pipeline natural gas.”

Simple combustion turbine means a unit that is a rotary engine driven by a gas under pressure that is created by the combustion of any fuel. This term includes combined cycle units without auxiliary firing. This term excludes combined cycle units with auxiliary firing, unless the unit did not use the auxiliary firing from 1985 through 1987 and does not use auxiliary firing at any time after November 15, 1990.

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....
- (b) The following types of units are not affected units subject to the requirements of the Acid Rain Program:
 - (1) A simple combustion turbine that commenced commercial operation before November 15, 1990.

Analysis: As SERC will interconnect to the electrical grid at SCE’s Barre Substation, the turbines will be new utility units. As these simple combustion turbines are expected to commence commercial operation after November 15, 1990, they are subject to the Acid Rain Program.

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§72.9 Standard requirements

(a) *Permit Requirements.*

- (1) The designated representative of each affected source and each affected unit at the source shall:
 - (i) Submit a complete Acid Rain permit application (including a compliance plan) under this part in accordance with the deadlines specified in §72.30;
 - (ii) Submit in a timely manner a complete reduced utilization plan if required under §72.43; and
 - (iii) Submit in a timely manner any supplemental information that the permitting authority determines is necessary in order to review an Acid Rain permit application and issue or deny an Acid Rain permit.

- (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 facility permit will indicate in the “Emissions and Requirements” column that the SO₂ and NO_x emissions 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. Appendix B 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)]

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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 (SO₂) 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, 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 SO₂. [40 CFR 72.9(c)(ii)]
6. Each ton of SO₂ 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. SO₂ 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 SO₂ allowance shall not be deducted in order to comply with the requirements under paragraph 41(A) of the SO₂ 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 SO₂ 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 SO₂ 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

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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, 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, 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;

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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, 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)]

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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, 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)]

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Subpart C—Acid Rain Permit Applications

§72.30 Requirement to apply

- (a) *Duty to apply.* The designated representative of any source with an affected unit shall submit a complete Acid Rain permit application by the applicable deadline in paragraphs (b) and (c) of this section, and the owners and operators of such source and any affected unit at the source shall not operate the source or unit without a permit that states its Acid Rain program requirements.
- (b) *Deadlines—*
- (2) *Phase II.*
- (ii) For any source with a new unit under §72.6(a)(3)(i), the designated representative shall submit a complete Acid Rain permit application governing such unit to the permitting authority at least 24 months before the later of January 1, 2000 or the date on which the unit commences operation.

Analysis: The initial Title V application, Application No. 589974, was submitted with the applications for permits to construct on 11/2/16. The application includes a completed (1) Form 500-F1 (Title V): Title IV –Acid Rain Phase II Facility Information Summary, and (2) Form 500-A2: Title V Application Certification, with Section IV – Designated Representative Certification Statement signed by Kara Miles, President.

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.

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Analysis: The Administrator allocated allowances to the existing units listed in tables 1 and 2, but is not allocating allowances to new utility units. SERC will be required to purchase SO_x allowances, 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.

Part 74—Sulfur Dioxide Opt-Ins
Subpart A—Background and Summary

§74.2 Applicability

Combustion or process sources that are not affected units under §72.6 of this chapter and that are operating and are located in the 48 contiguous States or the District of Columbia may submit an opt-in permit application to become opt-in sources upon issuance of an opt-in permit. Units for which an exemption under §72.7 or §72.8 of this chapter is in effect and combustion or process sources that are not operating are not eligible to submit an opt-in permit application to become opt-in sources.

Analysis: Part 74 is not applicable because the turbines, as new utility units, are affected sources under §72.6(a)(3)(i).

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 (SO₂), nitrogen oxides (NO_x), and carbon dioxide (CO₂) 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 SO₂ emissions, volumetric flow, NO_x emissions, opacity, CO₂ emissions and SO₂ 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 SO₂ mass emissions from gas-fired or oil-fired units and NO_x emissions from gas-fired peaking or

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oil-fired peaking units are included in appendices D [Optional SO₂ Emission Data Protocol for Gas-Fired and Oil-Fired Units] and E [Optional NO_x 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 CO₂ emissions are included in appendix G of this part [Determination of CO₂ 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 SO₂ or NO_x.

Analysis: The turbines, as new utility units, will be 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 SO₂, NO_x, CO₂, 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 SO₂, NO_x, CO₂, 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 CO₂ 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 CO₂ 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 SO₂ concentration, NO_x emission rate, CO₂ 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:

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- (1) The maximum potential concentration of SO₂, 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 CO₂ 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 H23.2 will require the turbines to comply with the applicable requirements of 40 CFR Part 75. The condition will include that the operator shall comply with the applicable requirements of §75.4 for monitoring systems installation and certification testing compliance dates.

Subpart B—Monitoring Provisions

§75.10 General operating requirements

- (a) *Primary Measurement Requirement.* The owner or operator shall measure opacity, and all SO₂, NO_x, and CO₂ emissions for each affected unit as follows:

- (1) To determine SO₂ emissions, the owner or operator shall install, certify, operate, and maintain, in accordance with all the requirements of this part, a SO₂ continuous emission monitoring system and a flow monitoring system with an automated data acquisition and handling system for measuring and recording SO₂ concentration (in ppm), volumetric gas flow (in scfh), and SO₂ mass emissions (in lb/hr) discharged to the atmosphere, except as provided in §§75.11 [specific provisions for monitoring SO₂ emissions] and 75.16 [special provisions for monitoring emissions from common, bypass, and multiple stacks for SO₂ 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 SO_x CEMS will not be required. The operator shall measure and record SO₂ emissions by using the applicable procedures specified in appendix D to this part for estimating hourly SO₂ mass emissions, an alternative provided by §75.11(d)(2). These applicable procedures estimate SO₂ mass emissions based on the sulfur content of the fuel and the amount of fuel combusted.

Condition H23.2 will include that the operator shall measure and record SO₂ emissions by using the applicable procedures specified in appendix D to Part 75 for estimating hourly SO₂ mass emissions, pursuant to §75.11(d)(2).

- (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

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O₂ or CO₂ diluent gas monitor) with an automated data acquisition and handling system for measuring and recording NO_x concentration (in ppm), O₂ or CO₂ concentration (in percent O₂ or CO₂) and NO_x emission rate (in lb/mmBtu) discharged to the atmosphere, except as provided in §§75.12 [specific provisions for monitoring NO_x 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 NO₂, either by monitoring for both NO and NO₂ or by monitoring for NO only and adjusting the emissions data to account for NO₂;

Analysis: Condition H23.2 will include that the NO_x CEMS shall comply with the applicable requirements of §75.10 for general operating requirements.

- (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 CO₂ CEMS is not required. Condition H23.2 will include that the operator shall measure and record CO₂ emissions by following the procedures in appendix G to Part 75 for estimating daily CO₂ mass emissions, pursuant to §75.10(a)(3)(ii) and §75.13(b).

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- (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 SO₂ and NO_x emissions in the appropriate units of measurement (*i.e.*, lb/hr for SO₂ 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 SO₂ concentrations, volumetric flow, SO₂ mass emissions, CO₂ concentration, O₂ concentration, CO₂ mass emissions (if applicable), NO_x concentration, and NO_x emission rate data collected by the monitors to hourly averages. Hourly averages shall be

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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 SO₂, CO₂, or O₂ 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 (O₂ or CO₂). For a moisture monitoring system consisting of one or more oxygen analyzers capable of measuring O₂ 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 SO₂ 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 CO₂ Emissions] of this part.

Analysis: As discussed for 75.10(a)(2) above, condition H23.2 will include that the NO_x CEMS shall comply with the applicable requirements of §75.10 for general operating requirements.

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§75.11 Specific provisions for monitoring SO₂ 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 SO₂ emissions:

- (1) By meeting the general operating requirements in §75.10 for an SO₂ 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 SO₂ Emissions Data Protocol for Gas-Fired and Oil Fired Units] for estimating hourly SO₂ mass emissions; or
- (3) By using the low mass emissions excepted methodology in §75.19(c) for estimating hourly SO₂ 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 SO₂, the LME methodology must also be used for NO_x and CO₂ when these parameters are required to be monitored by applicable program(s).

Analysis: Since the turbines are fired on natural gas only, a SO_x CEMS will not be required. As discussed above for §75.10(a)(1), condition H23.2 will include that the operator shall measure and record SO₂ emissions by using the applicable procedures specified in appendix D to Part 75 for estimating hourly SO₂ mass emissions, pursuant to §75.11(d)(2).

§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 O₂ or CO₂ 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 O₂ or CO₂), 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 H23.2 will include that the NO_x CEMS shall comply with the applicable requirements of §75.12 for specific provisions for monitoring NO_x emission rate.

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§75.13 Specific provisions for monitoring CO₂ emissions.

- (a) *CO₂ 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 CO₂ 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 “CO₂ continuous emission monitoring system” shall apply rather than “SO₂ continuous emission monitoring system,” the phrase “CO₂ concentration” shall apply rather than “SO₂ concentration,” the term “maximum potential concentration of CO₂” shall apply rather than “maximum potential concentration of SO₂,” and the phrase “CO₂ mass emissions” shall apply rather than “SO₂ mass emissions.”
- (b) *Determination of CO₂ emissions using appendix G to this part* [Determination of CO₂ 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 CO₂ 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 CO₂, 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 CO₂ mass emissions (in tons) in accordance with the procedures in appendix G to this part.
- (c) *Determination of CO₂ mass emissions using an O₂ monitor according to appendix F to this part* [Conversion Procedures]...

Analysis: As the turbines are fired on natural gas only, a CO₂ CEMS is not required. As discussed above for §75.10(a)(3), condition H23.2 will include that the operator shall measure and record CO₂ emissions by following the procedures in appendix G to Part 75 for estimating daily CO₂ mass emissions, pursuant to §75.10(a)(3)(ii) and §75.13(b).

§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

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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

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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

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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 SO₂, as defined in section 2.1.1.1 of appendix A to this part, to report SO₂ 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 CO₂, as defined in section 2.1.3.1 of appendix A to this part, to report CO₂ 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

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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 SO₂ 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;

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- (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 SO₂ 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 H23.2 will include that the operator shall comply with §75.20 for the initial certification requirements for the NO_x CEMS.

§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].

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- (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 H23.2 will include that the operator shall comply with §75.21 for the quality assurance and quality control requirements for the NO_x CEMS.

§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 O₂ and CO₂ concentrations in the emissions.

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- (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 SO₂ 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 SO₂ 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 NO₂, 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 O₂ or CO₂ concentration;
 - (2) Method 6C for determining SO₂ concentration;
 - (3) Method 7E for determining total NO_x concentration (both NO and NO₂);

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(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 H23.2 will include that the operator shall use the reference test methods in §75.22, or equivalent method(s) approved by the EPA. (The Source Testing Engineering Dept. explained that the EPA has approved the source test methods in SIP-approved rules.)

§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.

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- (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 SO₂ 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 H23.2 will include that the operator shall comply with §75.24 for out-of-control periods and adjustment for system bias requirements for the NO_x CEMS.

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 SO₂, NO_x, and flow rate
- §75.34 Units with add-on emission controls
- §75.35 Missing data procedures for CO₂
- §75.36 Missing data procedures for heat input rate determinations.

Analysis: Condition H23.2 will include that the operator shall comply with the applicable requirements of Subpart D--Missing Data Substitution Procedures.

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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 SO₂ emissions, NO_x emissions, CO₂ 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*

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(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 SO₂ 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

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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) *SO₂ 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

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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 SO₂ 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 O₂ or percent CO₂, rounded to the nearest tenth);
- (5) If applicable, the hourly average moisture content of the stack gas (percent H₂O, 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 O₂, 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;

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- (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) *CO₂ 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 CO₂ mass emissions, the owner or operator shall record or calculate CO₂ 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 O₂ 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 CO₂ diluent monitor (which is used only for heat input determination and is not used as a CO₂ pollutant concentration monitor) shall keep the following records for the O₂ or CO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ mass emissions:

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§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 SO₂ or NO_x pollutant concentration monitor, flow monitor, CO₂ emissions concentration monitor (including O₂ monitors used to determine CO₂ emissions), or diluent gas monitor (including wet- and dry-basis O₂ 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 SO₂ or NO_x pollutant concentration monitor, CO₂ emissions concentration monitor (including O₂ monitors used to determine CO₂ emissions), or diluent gas monitor (including wet- and dry-basis O₂ 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 SO₂ pollutant concentration monitor, flow monitor, each CO₂ emissions concentration monitor (including any O₂ concentration monitor used to determine CO₂ mass emissions or heat input), each NO_x-diluent continuous emission monitoring system, each NO_x concentration monitoring system, each diluent gas (O₂ or CO₂) 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:

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- (6) For each SO₂, NO_x, or CO₂ pollutant concentration monitor, each component of a NO_x-diluent continuous emission monitoring system, and each CO₂ or O₂ 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 SO₂ 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:

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- (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 H23.2 will include that the operator shall comply with the applicable requirements of Subpart F—Recordkeeping Requirements.

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

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- 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.

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- (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

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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

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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 SO₂ 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

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§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

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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).

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- (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;

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- (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 SO₂ 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;

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- (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 SO₂ 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);

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- (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 SO₂ emitted during the quarter and cumulative SO₂ 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 CO₂ emitted during quarter and cumulative CO₂ 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

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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 SO₂ 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 H23.2 will include that the operator shall comply with Subpart G—Reporting Requirements.

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

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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 NO_x 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 SO₂ 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 NO_x 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 SERC project is subject to CEQA because there are no applicable exemptions. The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger. On 10/26/16, SERC submitted the Application for Certification (AFC) (16-AFC-01) to the CEC for the SERC project. The CEC's 12-month licensing process is a certified regulatory program under CEQA. The CEC is the lead agency for the project.

The CEC will publish the Preliminary Staff Assessment (PSA) after the SCAQMD’s issuance of the Preliminary Determination of Compliance (PDOC). Typically, the PSA will indicate CEC is the CEQA

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lead agency, and CEC staff conducted its environmental analysis in accordance with the requirements of CEQA, and no additional environmental impact report (EIR) is required because the CEC’s site certification program has been certified by the California Resources Agency as meeting all requirements of a certified regulatory program. Further, the CEC’s siting regulations require staff to independently review the AFC and assess whether the list of environmental impacts contained is complete and additional or more effective mitigation measures are necessary, feasible, and available.

The PSA will examine environmental, public health and safety, and engineering aspects of the proposed SERC, based on the information provided by the applicant, government agencies (such as the SCAQMD), interested parties, and other sources available at the time the PSA was prepared. Further, the PSA will also recommend measures to mitigate significant and potentially significant environmental effects, which take the form of conditions of certification for construction, operation, maintenance, and eventual closure of the project, if approved by the CEC. The PSA will describe how the implementation of the conditions of certification will reduce potential adverse impacts to insignificant levels and ensure that the project’s emissions are mitigated to less than significant.

The PDOC (engineering evaluation) and proposed initial Title V permit were issued on 2/9/18 for review. The PSA was published by the CEC on 3/29/18 (http://docketpublic.energy.ca.gov/PublicDocuments/16-AFC-01/TN223086_20180329T153338_Stanton_Energy_Reliability_Center_Preliminary_Staff_Assessment.pdf). The public comment period on the PSA ended on 4/30/18.

The CEC procedure is that the PSA will serve as a precursor to the Final Staff Assessment (FSA). Following the 30-day comment period and a public workshop on the PSA (held on 4/18/18), staff will prepare a FSA which will serve as staff’s formal testimony in evidentiary hearings to be held by the Energy Commission’s Committee assigned to hear this case. The Committee will hold evidentiary hearings to consider the recommendations presented by staff, applicant, interveners, government agencies, and the public prior to proposing its decision. In the last step, the full Energy Commission will issue the final decision.

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 CO₂/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.”

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The local publicly owned electric utility from which SERC 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. Further, §2901(b) defines "baseload generation" to mean "electricity generation from a powerplant that is designed and intended to provide electricity at an annualized plant capacity factor of at least 60 percent." Based on a maximum of 902 hours at 100% load, the annual capacity factor is estimated to be 10.3% (902 hr/8760 hr), which is lower than the applicability threshold of 60%.

RECOMMENDATION


Based on the above analysis, it is recommended that the FDOC be published following the conclusion of the required review and comment periods for the CEC, EPA, other agencies and public, subject to any comments received during these periods. After the CEC issues the Final Commission Decision, the Permits to Construct may be issued.

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APPENDIX A--PLANNING, RULE DEVELOPMENT & AREA SOURCES (PRDAS) MODELING REVIEW MEMO, DATED 11/29/17

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

MEMORANDUM

DATE: November 29, 2017
TO: Andrew Lee
FROM: Jo Kay Ghosh 
SUBJECT: Modeling Review of Stanton Energy Reliability Center (Facility ID 183501) (A/N: 589935 – 589938, 589941, and 589974)

As you requested, Planning, Rule Development & Area Sources (PRDAS) staff reviewed a dispersion modeling analysis and Health Risk Assessment (HRA) conducted for the proposed new facility at Stanton Energy Reliability Center located at 10711 Dale Avenue in the city of Stanton. The project consists of two GE LM6000 Hybrid EGT units, which are combustion gas turbines with integrated battery storage components. The dispersion modeling analysis, HRA, and supporting electronic files were submitted for PRDAS staff review along with the modeling request memo dated July 14, 2017.

SUMMARY OF MODELING REVIEW

- **Modeling Conducted Pursuant to SCAQMD Regulations XIII Requirements**
 - ✓ The modeling requirements of Rule 1303(b)(1) apply to the proposed project for CO, NO₂, SO₂, PM_{2.5}, and PM₁₀. The modeled impacts are below all thresholds in Rule 1303 for CO, NO₂, SO₂, PM_{2.5}, and PM₁₀.
- **Modeling Conducted Pursuant to SCAQMD Regulation XIV Requirements**
 - ✓ The proposed project's health risks are less than the Rule 1401 cancer and non-cancer permit limits of 1 in one million (for permit units without T-BACT), and hazard index of 1, respectively.

DETAILED COMMENTS ON THE MODELING REVIEW

- **AERMOD Dispersion Modeling**
 - ✓ The applicant utilized AERMOD (version 15181) for the air dispersion modeling, which was the current U.S. EPA approved model at the time of the analysis.
 - ✓ The applicant used meteorological data from SCAQMD's Anaheim station for the years of 2006 – 2009 and 2012, which was appropriate meteorological data set at the time of the analysis.
 - ✓ The applicant used NED 1 arc-second terrain data as input into AERMAP (version 11103) to determine receptor, source, and building elevations, which is appropriate.
 - ✓ The modeling domain used was 10 kilometers by 10 kilometers, with fenceline spacing of 10 meters. A nested Cartesian receptor grid was used as follows: 20 meter spacing from the fenceline to approximately 500 meters from the fenceline; 100 meter spacing from 500 meters from the fenceline out to 1 kilometers; 200 meter spacing from 1 kilometer to 5 kilometers; and 500 meter spacing from 5 kilometers to 10 kilometers. Discrete Cartesian

receptors were placed at residential and off-site worker locations. The receptor grid selection is appropriate to capture the maximum impacts.

- ✓ The applicant used monitoring data from SRA 17, Central Orange County monitoring stations for the pollutants CO, NO₂, PM₁₀, and PM_{2.5} and monitoring data from SRA 18, North Coastal Orange County for the pollutant SO₂ for the last three years (2014 – 2016) to determine the background concentrations. The predicted modeled impacts were added to the highest background concentrations for comparison to the state and federal ambient air quality standards (AAQS), which is appropriate.
- ✓ The applicant used the URBAN dispersion option in AERMOD, with a population of 3,010,759 for Orange County, which is appropriate.
- ✓ PRDAS staff reproduced the dispersion modeling analysis and HRA, and the results are summarized below.

- **Impacts During Commissioning**

- ✓ Turbine commissioning is a once-in-a-lifetime event. The maximum emissions will occur prior to the installation of the catalyst for the turbines. Commissioning will be restricted to 100 hours per turbine.
- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in the revised Table 5.1-20, Page 5.1-26 of the report. Engineering & Permitting staff confirmed that the parameters were correct.

Table A – Impacts during Commissioning – Total Project

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration (µg/m ³)	Background Concentration ^a (µg/m ³)	Total Concentration (µg/m ³)	California AAQS ^b (µg/m ³)	Federal AAQS ^b (µg/m ³)	Exceeds Threshold?
CO, 1-hr	63.8	3,565.0	3,628.8	23,000	40,000	No
CO, 8-hr	21.3	2,530.0	2,551.3	10,000	10,000	No
NO ₂ , 1-hr ^c	39.5	146.6	186.1	339	- ^d	No

Note: ^a Maximum values for NO₂ and CO from SRA 17, Central Orange County (No. 3176) monitoring station for the last three years (2014 - 2016) was used.

^b Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted.

^c The conversion of NO_x to NO₂ was done using Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

^d 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.

Table B – Impacts during Commissioning – Turbine 1

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu\text{g}/\text{m}^3$)	Background Concentration ^a ($\mu\text{g}/\text{m}^3$)	Total Concentration ($\mu\text{g}/\text{m}^3$)	California AAQS ^b ($\mu\text{g}/\text{m}^3$)	Federal AAQS ^b ($\mu\text{g}/\text{m}^3$)	Exceeds Threshold?
CO, 1-hr	33.8	3,565.0	3,598.8	23,000	40,000	No
CO, 8-hr	11.3	2,530.0	2,541.3	10,000	10,000	No
NO ₂ , 1-hr ^c	20.9	146.6	167.5	339	- ^d	No

Note: ^a Maximum values for NO₂ and CO from SRA 17, Central Orange County (No. 3176) monitoring station for the last three years (2014 - 2016) was used.

^b Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted.

^c The conversion of NO_x to NO₂ was done using Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

^d On April 12, 2010, the U.S. EPA established a new 1-hour NO₂ standard of 100 ppb (188 $\mu\text{g}/\text{m}^3$). 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.

Table C – Impacts during Commissioning – Turbine 2

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu\text{g}/\text{m}^3$)	Background Concentration ^a ($\mu\text{g}/\text{m}^3$)	Total Concentration ($\mu\text{g}/\text{m}^3$)	California AAQS ^b ($\mu\text{g}/\text{m}^3$)	Federal AAQS ^b ($\mu\text{g}/\text{m}^3$)	Exceeds Threshold?
CO, 1-hr	33.7	3,565.0	3,598.7	23,000	40,000	No
CO, 8-hr	11.3	2,530.0	2,541.3	10,000	10,000	No
NO ₂ , 1-hr ^c	20.9	146.6	167.5	339	- ^d	No

Note: ^a Maximum values for NO₂ and CO from SRA 17, Central Orange County (No. 3176) monitoring station for the last three years (2014 - 2016) was used.

^b Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted.

^c The conversion of NO_x to NO₂ was done using Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

^d On April 12, 2010, the U.S. EPA established a new 1-hour NO₂ standard of 100 ppb (188 $\mu\text{g}/\text{m}^3$). 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.

- **Impacts During Normal Operations**

- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in the revised Table 5.1-20, Page 5.1-26 of the report. Engineering & Permitting staff confirmed that the parameters were correct.

Table D – Impacts during Normal Operation – Total Project

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu\text{g}/\text{m}^3$)	Background Concentration ^a ($\mu\text{g}/\text{m}^3$)	Total Concentration ($\mu\text{g}/\text{m}^3$)	California AAQS ^b ($\mu\text{g}/\text{m}^3$)	Federal AAQS ^b ($\mu\text{g}/\text{m}^3$)	Exceeds Threshold?
CO, 1-hr	9.3	3,565.0	3,574.3	23,000	40,000	No
CO, 8-hr	2.2	2,530.0	2,532.2	10,000	10,000	No
NO ₂ , 1-hr ^c	6.2	146.6	152.8	339	-	No
NO ₂ , 1-hr ^c	2.5	111.4	113.8	-	188 ^d	No
NO ₂ , Annual ^c	0.02	50.8	50.82	57	100	No
SO ₂ , 1-hr	0.4	23.1	23.5	655	196 ^e	No
SO ₂ , 3-hr	0.3	23.1	23.4	-	1,300	No
SO ₂ , 24-hr	0.07	3.7	3.77	105	-	No
PM ₁₀ , 24-hr	0.5	95.0	95.5	-	150 ^f	No
Non-attainment Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu\text{g}/\text{m}^3$)	California AAQS ($\mu\text{g}/\text{m}^3$)	Federal AAQS ($\mu\text{g}/\text{m}^3$)	Rule 1303 Thresholds ^g ($\mu\text{g}/\text{m}^3$)		Exceeds Threshold?
PM ₁₀ , 24-hr	0.5	50	-	2.5		No
PM ₁₀ , Annual	0.02	20	-	1		No
PM _{2.5} , 24-hr	0.5	-	35	2.5		No
PM _{2.5} , Annual	0.02	12	12	1		No

Note: ^a Maximum values for CO, NO₂, and PM₁₀ from SRA 17, Central Orange County (No. 3167) monitoring station and SO₂ from SRA 18, North Coastal Orange County (No. 3195) monitoring station for the last three years (2014 - 2016) was used.

^b Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted.

^c The conversion of NO_x to NO₂ was done using Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

^d On April 12, 2010, the U.S. EPA established a new 1-hour NO₂ standard of 100 ppb (188 $\mu\text{g}/\text{m}^3$). 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.

^e On June 2, 2010, the U.S. EPA established a new 1-hour SO₂ standard of 75 ppb (196 $\mu\text{g}/\text{m}^3$). 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.

^f Effective July 26, 2013, the South Coast Air Basin has been re-designated to attainment for the federal 24-hour PM₁₀ AAQS.

^g The South Coast Air Basin is designated non-attainment for the state PM₁₀ standards, and state and federal PM_{2.5} standards; therefore, project increments are compared to the significant change thresholds in Rule 1303.

Table E – Impacts during Normal Operation – Turbine 1

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu\text{g}/\text{m}^3$)	Background Concentration ^a ($\mu\text{g}/\text{m}^3$)	Total Concentration ($\mu\text{g}/\text{m}^3$)	California AAQS ^b ($\mu\text{g}/\text{m}^3$)	Federal AAQS ^b ($\mu\text{g}/\text{m}^3$)	Exceeds Threshold?
CO, 1-hr	4.9	3,565.0	3,569.9	23,000	40,000	No
CO, 8-hr	1.2	2,530.0	2,531.2	10,000	10,000	No
NO ₂ , 1-hr ^c	3.3	146.6	149.9	339	-	No
NO ₂ , 1-hr ^c	1.3	111.4	112.7	-	188 ^d	No
NO ₂ , Annual ^c	0.01	50.8	50.81	57	100	No
SO ₂ , 1-hr	0.2	23.1	23.3	655	196 ^e	No
SO ₂ , 3-hr	0.2	23.1	23.3	-	1,300	No
SO ₂ , 24-hr	0.04	3.7	3.74	105	-	No
PM ₁₀ , 24-hr	0.3	95.0	95.3	-	150 ^f	No
Non-attainment Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu\text{g}/\text{m}^3$)	California AAQS ($\mu\text{g}/\text{m}^3$)	Federal AAQS ($\mu\text{g}/\text{m}^3$)	Rule 1303 Thresholds ^g ($\mu\text{g}/\text{m}^3$)		Exceeds Threshold?
PM ₁₀ , 24-hr	0.3	50	-	2.5		No
PM ₁₀ , Annual	0.01	20	-	1		No
PM _{2.5} , 24-hr	0.3	-	35	2.5		No
PM _{2.5} , Annual	0.01	12	12	1		No

Note: ^a Maximum values for CO, NO₂, and PM₁₀ from SRA 17, Central Orange County (No. 3167) monitoring station and SO₂ from SRA 18, North Coastal Orange County (No. 3195) monitoring station for the last three years (2014 - 2016) was used.

^b Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted.

^c The conversion of NO_x to NO₂ was done using Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

^d On April 12, 2010, the U.S. EPA established a new 1-hour NO₂ standard of 100 ppb (188 $\mu\text{g}/\text{m}^3$). 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.

^e On June 2, 2010, the U.S. EPA established a new 1-hour SO₂ standard of 75 ppb (196 $\mu\text{g}/\text{m}^3$). 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.

^f Effective July 26, 2013, the South Coast Air Basin has been re-designated to attainment for the federal 24-hour PM₁₀ AAQS.

^g The South Coast Air Basin is designated non-attainment for the state PM₁₀ standards, and state and federal PM_{2.5} standards; therefore, project increments are compared to the significant change thresholds in Rule 1303.

Table F – Impacts during Normal Operation – Turbine 2

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu\text{g}/\text{m}^3$)	Background Concentration ^a ($\mu\text{g}/\text{m}^3$)	Total Concentration ($\mu\text{g}/\text{m}^3$)	California AAQS ^b ($\mu\text{g}/\text{m}^3$)	Federal AAQS ^b ($\mu\text{g}/\text{m}^3$)	Exceeds Threshold?
CO, 1-hr	4.9	3,565.0	3,569.9	23,000	40,000	No
CO, 8-hr	1.2	2,530.0	2,531.2	10,000	10,000	No
NO ₂ , 1-hr ^c	3.3	146.6	149.9	339	-	No
NO ₂ , 1-hr ^c	1.3	111.4	112.7	-	188 ^d	No
NO ₂ , Annual ^c	0.01	50.8	50.81	57	100	No
SO ₂ , 1-hr	0.2	23.1	23.3	655	196 ^e	No
SO ₂ , 3-hr	0.2	23.1	23.3	-	1,300	No
SO ₂ , 24-hr	0.04	3.7	3.74	105	-	No
PM ₁₀ , 24-hr	0.3	95.0	95.3	-	150 ^f	No
Non-attainment Pollutant & Averaging Time	Maximum Modeled Concentration ($\mu\text{g}/\text{m}^3$)	California AAQS ($\mu\text{g}/\text{m}^3$)	Federal AAQS ($\mu\text{g}/\text{m}^3$)	Rule 1303 Thresholds ^g ($\mu\text{g}/\text{m}^3$)		Exceeds Threshold?
PM ₁₀ , 24-hr	0.3	50	-	2.5		No
PM ₁₀ , Annual	0.01	20	-	1		No
PM _{2.5} , 24-hr	0.3	-	35	2.5		No
PM _{2.5} , Annual	0.01	12	12	1		No

Note: ^a Maximum values for CO, NO₂, and PM₁₀ from SRA 17, Central Orange County (No. 3167) monitoring station and SO₂ from SRA 18, North Coastal Orange County (No. 3195) monitoring station for the last three years (2014 - 2016) was used.

^b Both the California and Federal AAQS values listed are not to be exceeded, except otherwise noted.

^c The conversion of NO_x to NO₂ was done using Tier 2 conversion ratios of 0.8 for 1-hour and 0.75 for annual.

^d On April 12, 2010, the U.S. EPA established a new 1-hour NO₂ standard of 100 ppb (188 $\mu\text{g}/\text{m}^3$). 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.

^e On June 2, 2010, the U.S. EPA established a new 1-hour SO₂ standard of 75 ppb (196 $\mu\text{g}/\text{m}^3$). 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.

^f Effective July 26, 2013, the South Coast Air Basin has been re-designated to attainment for the federal 24-hour PM₁₀ AAQS.

^g The South Coast Air Basin is designated non-attainment for the state PM₁₀ standards, and state and federal PM_{2.5} standards; therefore, project increments are compared to the significant change thresholds in Rule 1303.

- **SCAQMD Regulation XIV – Health Risk Impacts**

- ✓ The applicant performed the HRA with the Hot Spots Analysis and Reporting Program (HARP2, version 16217). The SCAQMD's HRA procedures require HARP to be used in Tier 4 risk assessments.

- ✓ The stack parameters and emission rates modeled are consistent with the parameters listed in revised Tables 5.1-26, 5.9-4, and 5.9-5 of the report. Engineering & Permitting staff confirmed that the parameters were correct.

Table G – Health Risk Impacts - Total Project

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Sensitive	0.06 in one million (5.57 E-08)	0.00008 (7.93 E-05)	0.002 (1.60 E-03)	One in one million ^a (1.0 E-06)	1.0	1.0	No
Worker	0.002 in one million (2.01 E-09)	0.00009 (9.30 E-05)	0.002 (1.71 E-03)	One in one million ^a (1.0 E-06)	1.0	1.0	No

Note: ^a 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}).

Table H – Health Risk Impacts – Turbine 1

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Sensitive	0.03 in one million (2.80 E-08)	0.00004 (4.00 E-05)	0.0008 (8.31 E-04)	One in one million ^a (1.0 E-06)	1.0	1.0	No
Worker	0.001 in one million (9.43 E-10)	0.00004 (4.37 E-05)	0.001 (9.54 E-04)	One in one million ^a (1.0 E-06)	1.0	1.0	No

Note: ^a 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}).

Table I – Health Risk Impacts – Turbine 2

Receptor Type	Cancer Risk	Chronic Hazard Index	Acute Hazard Index	Cancer Risk Threshold	Chronic HI Threshold	Acute HI Threshold	Exceeds Any Threshold?
Sensitive	0.03 in one million (2.80 E-08)	0.00004 (3.99 E-05)	0.0006 (5.61 E-04)	One in one million ^a (1.0 E-06)	1.0	1.0	No
Worker	0.001 in one million (1.06 E-09)	0.00005 (4.92 E-05)	0.0008 (8.29 E-04)	One in one million ^a (1.0 E-06)	1.0	1.0	No

Note: ^a 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 x 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 x 10⁻⁵).

• **Fumigation Air Quality Analyses**

- ✓ Since the proposed project occurs in an area where nocturnal radiation inversions are broken up by solar warming near the surface, inversion break-up impacts from the project were analyzed. During these short term events, the maximum impacts could be higher.
- ✓ Inversion break-up was evaluated in the report for 1-hour NO₂, 1-hour, 3-hour, and 24-hour SO₂, 1-hour and 8-hour CO, 24-hour PM₁₀, and 24-hour PM_{2.5}. Because this meteorological phenomena does not persist for long periods, only the shorter averaging periods (≤ 8 hrs) should be considered.
- ✓ AERSCREEN (version 16216) was utilized for the analysis. The modeling parameters for the worst-case operating scenarios were used for each of the modeled pollutants and averaging times. AERSCREEN is the model EPA recommends to analyze impacts from inversion break-up and shoreline fumigation. However, AERSCREEN cannot provide results that correspond to the federal ambient air quality standards for NO₂ and SO₂, due to the form of those standards. For these pollutants, the maximum value is reported in the table below instead of the 98th or 99th percentile, respectively.
- ✓ Inversion break-up impacts, combined with background concentrations, are below the applicable ambient air quality standards.

Table J – Impacts during Normal Operations for Inversion Break-Up – Total Project

Attainment Pollutant & Averaging Time	Maximum Modeled Concentration (µg/m³)	Background Concentration^a (µg/m³)	Total Concentration (µg/m³)	Federal AAQS^b (µg/m³)	California AAQS (µg/m³)
CO, 1-hr	2.7	3,910.0	3,912.7	40,000	23,000
CO, 8-hr	2.4	2,990.0	2,992.4	10,000	10,000
NO ₂ , 1-hr	2.2	152.3	154.5	-	339
SO ₂ , 1-hr	0.6	23.1	23.7	-	655
SO ₂ , 3-hr	0.6	23.1	23.7	1,300	-

Note: ^a Maximum values for CO and NO₂ from SRA 17, Central Orange County (No. 3167) monitoring station and SO₂ from SRA 18, North Coastal Orange County (No. 3195) monitoring station for the last three years (2014 - 2016) was used

^b Both the California and Federal AAQS values listed are not to be exceeded. The federal NO₂ and SO₂ standards cannot be evaluated with AERSCREEN due to the form of those standards and are not considered in this analysis.

Modeling staff spent a total of 135 hours, including 15 hours of overtime, on this review. Please direct any questions to Melissa Sheffer at ext. 2346.

cc: Vicky Lee
JKG:MS

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	PROCESSED BY V. Lee	CHECKED BY

APPENDIX B—SCAQMD RESPONSE LETTER TO SERC
COMMENTS



South Coast Air Quality Management District

21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 • www.aqmd.gov

April 19, 2018

Kara Miles
President
Stanton Energy Reliability Center, LLC
650 Bercut Drive, Suite A
Sacramento, CA 95811

SUBJECT: Stanton Energy Reliability Center, LLC (SERC) (Facility ID 183501)
Response to Preliminary Determination of Compliance Comments

Dear Ms. Miles:

The South Coast Air Quality Management District (SCAQMD) received SERC's comment letter, dated February 20, 2018, on the Stanton Energy Reliability Center Preliminary Determination of Compliance (PDOC), issued February 9, 2018. In response to SERC's request, SCAQMD staff and SERC representatives discussed the comments in a conference call on March 1, 2018. The SCAQMD's responses are presented below in the same order as SERC's comments.

SERC Comments

Condition A63.1 SO_x emissions: We note that the single turbine monthly SO_x emission limit of 758 lbs in any calendar month exceeds the annual limit in A63.2 of 595 lbs per year for both turbines combined. While we understand that the difference between the two emissions limits is based on the fuel bound sulfur content of 0.25 grains/100 scf (annual) and 0.75 grains/100 scf (short-term), establishing the monthly limit with a higher amount of SO_x than the annual limit may lead to confusion in how to demonstrate compliance. We recognize the use of two sets of emission factors and limits that are used for compliance:

Short-term

- 0.75 grains/100 scf (emission factor)
- 1.02 lb/hr (short-term mass limit)
- 2.14 lb/mmscf (compliance monitoring limit)

Annual

- 0.25 grains/100 scf (emission factor)
- 0.33 lb/hr (long-term mass emission limit)
- 0.72 lb/mmscf (compliance monitoring limit)

We would propose that condition A63.1 references that the monthly emissions are based on the 0.75 grains/100 scf and propose that for Condition A63.2, the sulfur limit is referenced to 0.25 grains/100 scf.

Delivered by email on 4/19/18

SCAQMD Response

The following minor changes to conditions A63.1 and A63.2 will provide clarification regarding the basis of the monthly and annual emission limits and associated emission factors for SO_x.

- Condition A63.1

For normal operation, VOC, PM10/PM2.5, and SO_x emissions shall be calculated using the following emission factors: VOC, 3.26 lb/mmcf; PM10/PM2.5, 6.32 lb/mmcf; and SO_x, 2.14 lb/mmcf (**based on 0.75 grains S/100 scf**).

- Condition A63.2

The yearly emissions limits in this condition shall be calculated from the monthly emissions, including emissions for the commissioning period, as required by condition A63.1, except the normal operation annual emission factor for SO_x is 0.72 lb/mmcf (**based on 0.25 grains S/100 scf (annual average)**).

Condition A63.1 Pre-Catalyst and Post-Catalyst Phases: The proposed Pre-Catalyst and Post-Catalyst Phases described in Condition A63.1 relied on the Commissioning Emissions Table provided by SERC. However, although the table correctly presented the Pre and Post-Catalyst Emissions Factors and associated fuel use for each phase, several cells in the table contained incorrect labels and therefore led to confusion when the Condition was drafted.

For the activities labeled “Subtotal – Pre-Catalyst Phases, hrs | lbs” and “Subtotal – Post-Catalyst Phase, hrs | lbs”, the column labeled “Step No.” provided an incorrect label to summarize the Pre and Post-Catalyst steps, and Steps 4 and 5 the column labeled “Notes” incorrectly indicated that the SCR and CO catalysts would not be installed. A marked-up version of the Commissioning Emissions Table is attached to this response letter as Exhibit A, and correctly labels the subtotal rows and shows that the catalysts will be installed prior to the commencement of Step 4. We note that the remainder of the table’s content and underlying analysis for the pre and post-catalyst phases are correct and were based on catalyst installation occurring prior to Step 4.

With the corrections to the table’s labels and notes, we propose the following correction to the pre and post-catalyst phases as referenced in this condition. The pre-catalyst phase ends with Step 3 (first synchronization) rather than Step 5 (full load operation with water injection and SPRINT in service), and the post-catalyst phase begins with Step 4 (synchronization and ramp to full load, tuning water, ammonia (rough), and AVR (as needed), gas compressor tuning). Correcting the condition’s description of the pre and post-catalyst phases will not change the compliance emission factors as summarized in A63.1. It will only change the number of steps in the pre and post-catalyst phases. Our proposed language is as follows:

Pre-Catalyst Phase: CO, 155.08 lb/mmcf; VOC, 24.60 lb/mmcf; PM10/PM2.5, 32.09 lb/mmcf; and SO_x, 2.14 lb/mmcf. The pre-catalyst phase starts with step 1 of the commissioning activities (first fire and full speed, no load, not synchronized, no generator excitation) and ends with step 3 (First synchronization) 5 (full load operation with water

~~injection and SPRINT in service). The steps referenced herein are described in the Commissioning Emissions (per Turbine) table provided by Stanton Energy Reliability Center.~~

~~Post-Catalyst Phase: CO, 6.70 lb/mmcf; VOC, 3.42 lb/mmcf; PM10/PM2.5, 8.29 lb/mmcf; and SO_x, 2.14 lb/mmcf. The post-catalyst phase is are comprised of steps 4 (Synchronization and ramp to full load, tuning water, ammonia (rough) and AVR (as needed), gas compressor tuning), 5 (Full load operation with water injection and SPRINT in service) and 6 (Full load operation with water injection and SPRINT in service and SCR/ammonia tuning) of the commissioning activities. (full load operation with water injection and SPRINT in service and SCR/ammonia tuning).~~

SCAQMD Response

The minor corrections shown in the revised Commissioning Emissions (per Turbine) table provided in Exhibit A to SERC’s comment letter are noted, and condition A63.1 will be revised to incorporate the corrected descriptions of pre-catalyst phase and post-catalyst phase.

Condition A63.2: SERC requests the following minor modifications to the second paragraph following the annual emission limit table in Condition A63.2 to avoid potential confusion between the term “emissions limits” and actual emissions as follows:

The ~~yearly~~ **annual** emissions ~~limits of the facility for purposes of demonstrating compliance with~~ ~~in~~ this condition shall be calculated from the monthly emissions, including emissions for the commissioning period, as required by condition A63.1, except the normal operation annual emission factor for SO_x is 0.72 lb/mmcf.

SCAQMD Response

As SERC’s proposed language for Condition A63.2 correctly reflects the intent of the condition, the condition will be revised accordingly.

Condition B61.1: The condition language relating to the fuel composition could be confusing as it could be interpreted that the sulfur content cannot exceed 0.25 grains per 100 SCF for any averaging period. We would propose the following changes:

The operator shall not use natural gas containing the following specified compounds:

<i>Compound</i>	<i>Range</i>	<i>grain per 100 scf</i>
<i>H2S</i>	<i>Less than or equal to</i>	<i>0.25 (annual average)</i>
<i>H2S</i>	<i>Less than or equal to</i>	<i>0.75 (monthly average)</i>

SCAQMD Response

The proposed language does not fully convey the testing requirements of Condition B61.1. Condition B61.1 is a standard condition for power plants for which monthly SO_x emission is based on 0.75 grains S/100 scf, and annual SO_x emissions is based on

0.25 grains S/100 scf. SCAQMD inspectors are familiar with the condition and its requirements. Pursuant to SERC's comment, discussed above, conditions A63.1 and A63.2 will be revised to provide the requested clarification that the monthly emission factor is based on 0.75 grains S/100 scf, and the annual emission factor is based on 0.25 grains S/100 scf (annual average). Therefore, the same clarification need not be included in Condition B61.1.

Condition C1.1 and C1.2: SERC requests the District delete the daily limit on startups and on shutdowns in Conditions C1.1 and C1.2. The daily limits are not required to ensure compliance with any District Rule and are not required to ensure emissions compliance with any ambient air quality standard. The limits on monthly and annual startups and shutdowns, in combination with (i) the monthly and annual emissions limits, and (ii) the emission limits on startup and shutdown events, are sufficient to ensure that the facility, and each turbine, will not exceed its Potential to Emit. Although the PDOC (at page 38) states that SERC initially requested a maximum daily limit on startups and shutdowns of 6 per turbine, and subsequently requested a reduction to 4 daily starts/shutdowns per turbine, SERC did not provide these quantities to serve as limits, but instead used the number of startups and shutdowns (4 per day) to explain the derivation of maximum emissions utilized for the 8-hour and 24-hour dispersion modeling cases. When using these maximum assumed emissions, the resultant dispersion modeling outcomes indicated that no California or National Ambient Air Quality SILs would be exceeded. Additionally, the results of the dispersion modeling assessment would not be affected by the removal of this condition as the 24-hour standards for PM₁₀/2.5 and SO_x already assumed the worst-case operating condition of 24-hours of full load with no starts or shutdowns. The number of daily startups and shutdowns were not considered for the 24-hour modeling analyses.

Because the monthly and annual emission limits are all based on the total emissions and duration, rather than the number, of startup and shutdown events that may occur in any calendar day for each gas turbine, SERC proposes to eliminate the limitation on the total number of such daily events.

If the daily limits are deleted as requested, the District can still make the findings that the conditions of the PDOC will ensure compliance with all District Rules and will not result in violation of any ambient air quality standard.

The proposed language change is as follows:

C1.1 The operator shall limit the number of start-ups to no more than 124 in any one calendar month.

For the purposes of this condition, the limits are for one turbine, except the annual limit is the combined total for two turbines (D1 and D7). ~~The number of startups shall not exceed 4 startups in any one day.~~ The number of startups shall not exceed 1000 in any calendar year.

A startup shall not exceed 15 minutes. The NOx emissions from a startup shall not exceed 3.6 lbs. The CO emissions from a startup shall not exceed 5.3 lbs.

The beginning of startup occurs at initial fire in the combustor and the end of startup occurs when the BACT levels are achieved. If during startup the process is aborted the process will count as one startup.

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.

C1.2 The operator shall limit the number of shutdowns to no more than 124 in any one calendar month.

For the purposes of this condition, the limits are for one turbine, except the annual limit is the combined total for two turbines (D1 and D7). ~~The number of shutdowns shall not exceed 4 shutdowns in any one day.~~ The number of shutdowns shall not exceed 1000 in any calendar year.

Each shutdown shall not exceed 10 minutes. The NOx emissions from a shutdown event shall not exceed 0.55 lbs. The CO emissions from a shutdown event shall not exceed 0.24 lbs.

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. The records shall be maintained for a minimum of 5 years in a manner approved by SCAQMD.

SCAQMD Response

In lieu of requiring steady state BACT at all times, an alternative BACT which limits and minimizes emissions during periods when steady state BACT is not achievable, such as during startups and shutdowns, has been accepted by EPA. Conditions limiting the number of startups and shutdowns per day have been included on recent power plant facility permits to implement alternative BACT. If SERC determines that four startups and shutdowns per day is insufficient, applications to increase the daily number of startups and shutdowns can be submitted to revise the condition.

Condition D29.1: This condition could be interpreted as requiring PM10 and PM2.5 source tests, of at least four (4) hours for each test, for turbine loads at 50, 75 and 100 percent loads. We note that PM source test results are well correlated to fuel flow and load. Our PM emission rates for all loads is 3.0 lbs/hr and the requirement to test each load (50, 75 and 100) would be excessive. We would propose to add in the language from D29.2 as follows:

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

The test shall be conducted when the turbine is operating at 100 percent of maximum load.

SCAQMD Response

SERC's interpretation of Condition D29.1 is correct. The initial source test condition requires PM₁₀ and PM_{2.5} source testing, of at least four hours for each test, for turbine loads at 50, 75, and 100 percent loads. This same initial source test condition has been included on other recent power plant permits.

Condition E193.3: As explained in the comments on Condition A63.1, several incorrect labels in the Commissioning Emissions Table created drafting confusion. As shown in Exhibit A to this comment letter, the pre-catalyst phase of commissioning will occur over 20 hours for Steps 1 through 3. We propose the following change to this condition:

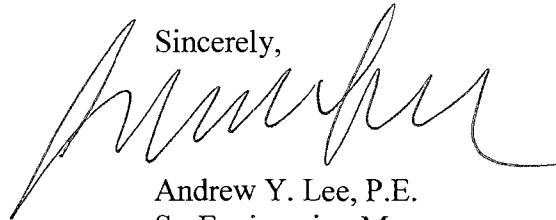
Total commissioning hours shall not exceed 100 hours of fired operation for each turbine from the date of initial turbine start-up. Of the 100 hours, commissioning hours without control (pre-catalyst phase as defined in condition A63.1) shall not exceed ~~38~~ 20 hours.

SCAQMD Response

The minor corrections shown in the revised Commissioning Emissions (per Turbine) table provided in Exhibit A to SERC's comment letter are noted, and condition E193.3 will be revised to correct the number of uncontrolled commissioning hours as proposed.

If you have any questions regarding our responses to your comments, please contact me at (909) [396-2643](tel:396-2643)/alee@aqmd.gov.

Sincerely,



Andrew Y. Lee, P.E.
Sr. Engineering Manager
Engineering and Permitting

AYL:BC:RC:VL

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